OLSON, BZDOK & HOWARD

June 22, 2021

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-20963

Dear Ms. Felice:

The following is attached for paperless electronic filing:

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

Exhibits MEC-46 through MEC-69; and

Proof of Service.

The confidential version will be served only to those with a signed non-disclosure certificate on file.

Sincerely,

Tracy Jane Andrews
tjandrews@envlaw.com

xc: Parties to Case No. U-20963

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-20963 ALJ Sharon Feldman

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PUBLIC VERSION

Direct Testimony

of

Tyler Comings

On Behalf of

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

June 22, 2021

TABLE OF CONTENTS

DIRECT TESTIMONY OF TYLER COMINGS
U-20963

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. 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) (collectively, "MNSC").

Q. Please summarize your work experience and educational background.

A. I have 15 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 Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, 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 (now EBP).

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-46.

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

A. Yes, on four occasions. Most recently, I testified in Consumers Energy Company's ("Consumers" or "the Company") 2020 rate case (Case No. U-20697). 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 Consumers' 2018 IRP (Case No. U-20165) and testified in Consumers' 2018 rate case (Case No. U-20134).

Q. What is the purpose of your testimony?

A. I address three main issues in my testimony. First, I address the economic value of coal-fired units 1 and 2 at the J.H. Campbell plant, and the importance of considering those units for a mid-2020s retirement. Second, I address Consumers' request for rate recovery of certain capital expenditures at the Campbell plant. I discuss capital projects that could be avoided if Campbell 1 and 2 retired by the mid-2020s, as well as other projects, including at Campbell unit 3, that lack supporting documentation or face significant uncertainties, and recommend spending disallowances accordingly. Many of these projects were disallowed in Case No. U-20697,[1] and the Commission's reasons for disallowing these projects last year still apply to Consumers' current rate request. Third, I discuss the transition planning efforts related to Karn units 1 and 2, two coal-fired units scheduled for retirement in May 2023, and recommend additional transparency and public engagement related to this process.

[1] See Case No. U-20697, Dec. 17, 2020, Order, pp. 73, 77, 78, 79, 80, 94, 182.

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, and several permitting documents related to the Campbell plant.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I sponsor Exhibits MEC-46 to MEC-69C:

MEC-46:	Comings Resume
MEC-47:	Fixed O&M Costs at Campbell 1 & 2
MEC-48:	MEC-CE-014 + U0697-MEC-CE-546
MEC-49:	U20697-MEC-CE-032 + MEC-CE-016
MEC-50:	2021/2022 Planning Resource Auction (PRA) Results (Apr. 15, 2021)
MEC-51:	MEC-CE-017 + U20693-MEC-CE-017-Hugo_ATT_1; U20697-MEC-CE-033
MEC-52:	Net Energy Values (NEVs) for Campbell 1 & 2
MEC-53:	MEC-CE-662 + U20963-MEC-CE-662-Coker_ATT_1; MEC-CE-663-64, 994, 1001-02
MEC-54C:	MEC-CE-1048-CONFIDENTIAL (Confidential)
MEC-55:	Capacity Factors, Availability, Periodic Factors, and Random Outage Rates for Campbell 1&2
MEC-56:	Campbell Capital Expenditures – Recommended Disallowances
MEC-57:	MEC-CE-013 (Revised), MEC-CE-023, 644, 647, 983-87
MEC-58:	Projected capital expenditures at the Campbell plant, 2021-25
MEC-59:	MEC-CE-022, 640, 642
MEC-60C:	U20697-MEC-CE-1027-CONF (Confidential)
MEC-61:	Letter from Consumers Energy Company to EGLE Re: J.H. Campbell Complex NPDES Permit No. MI0001422 (produced as U20963-ST-CE-454-Breining_ATT_1)
MEC-62:	MEC-CE-032-034, 651-54, 655 (Supplemental), 922, ST-CE-454

MEC-63:	Draft NPDES Permit Modification for J.H. Campbell Plant, Permit No. MI0001422
MEC-64:	Appalachian Voices v. U.S. EPA, Case No. 20-2187 (L), Doc. 60, Unopposed Motion to Hold Merits Briefing Schedule in Abeyance (May 25, 2021) (4th Cir.); id., Doc. 61, Order Extending Abeyance (June 1, 2021)
MEC-65:	MEC-CE-027 + U20963-MEC-CE-027-Hugo_ATT_1; MEC-CE-638 + U20963-MEC-CE-638-Hugo_ATT_1
MEC-66C:	MEC-CE-996-CONF + MEC-CE-997-CONF + MEC-CE-998-CONF (Confidential)
MEC-67:	U20697-MEC-CE-1014
MEC-68:	MEC-CE-028 + U20963-MEC-CE-028-Hugo_ATT_1, MEC-CE-659, U20697-MEC-CE-549, U20697-MEC-CE-1029
MEC-69C:	U20697-MEC-CE-053-Hugo_CONF_ATT_1 (Confidential)

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:[2]

- Campbell unit 1: 259 MW capacity, 59 years old
- Campbell unit 2: 348 MW capacity, 54 years old
- Campbell unit 3: 784 MW capacity (Consumers' owned share), 41 years old
- Karn unit 1: 255 MW capacity, 62 years old
- Karn unit 2: 260 MW capacity, 60 years old

[2] Direct Testimony of Scott A. Hugo, p. 6, Table 1.
Note: my testimony includes some references to testimony and exhibits from Consumers' 2020 rate case, No. U-20697, and record citations from that case are identified by the case number. Unless otherwise noted, citations to witness testimony, exhibits, and discovery responses are referring to this case.

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.[3] Consumers selected these dates as part of its Proposed Course of Action (PCA) in the Company's 2018 Integrated Resource Plan.[4] In the IRP review case, No. U-20165, I submitted testimony that discussed flaws with Consumers' proposal to operate Campbell units 1 and 2 through 2031, and concluded that ratepayers would likely save money if these units retired earlier.[5] Subsequently, Consumers and most parties in that case reached a settlement, which the Commission approved. Under the settlement agreement, Consumers' next IRP must evaluate the potential retirement of Campbell units 1 and 2 in 2024, 2025, 2026, 2028, and 2031.[6] The Company's 2021 IRP will be filed at the end of June 2021. Thus, the question of when Campbell units 1 and 2 should retire will be re-evaluated in the 2021 IRP.

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

A. For Campbell units 1 and 2, the Company plans to spend $27.35 million in capital expenditures in the 2021 bridge year and $12.74 million in capital expenditures in the 2022 test year.[7] Capital projects are typically medium to long-term investments that are financed with debt and equity and recovered over many years. The Company also plans to incur

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[3] *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 879-80 (noting that the PCA's capacity outlook assumes that "Campbell unit 3 is retired at end of year 2039 versus 2040 to align with the Company's Clean Energy Goals").
[4] Case No. U-20165, Application, p. 2.
[5] See generally Case No. U-20165, Revised Direct Testimony of Tyler Comings, 8 TR 1824-63.
[6] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Exhibit A, Par 4.
[7] Ex A-12 (SAH-3), Sch B-5.2, p. 5.

$24.7 million in operations and maintenance (O&M) costs at these units in 2022.[8] This spending includes both base O&M spending, as well as major maintenance – larger O&M projects that are performed less regularly.[9]

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 settlement agreement in the 2018 IRP case, the Company agreed to identify these "avoidable" costs in any rate case filed before its next IRP filing (*i.e.*, the 2020 rate case and this case). Specifically, the Company agreed to identify costs that could be avoided if Campbell units 1 and/or 2 retired in 2024 or 2025.[10]

Because the retirement date of Campbell units 1 and 2 will be decided in the 2021 IRP, the identification of avoidable costs is important for the Commission's determination of which costs to include in rate base. The retirement dates are relevant because they affect whether the planned capital and maintenance spending costs are reasonable and prudent. In last year's rate case, I recommended disallowing costs that could be avoided if Campbell 1 and 2 retire by 2024, and the Commission ultimately disallowed those costs. Including avoidable costs in rates now would prevent ratepayers from realizing this savings should the units retire before 2031.

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[8] Ex MEC-47 (total projected O&M costs of $12.6 million at Campbell 1, and $12.2 million at Campbell 2).
[9] Hugo Direct, pp. 114, 120.
[10] Case No. U-20165, June 7, 2019, Order Approving Settlement Agreement, Ex A, Par 6 ("The parties agree that the Company will identify in its intervening rate cases avoidable capital expenditures (environmental and non-environmental) and avoidable major maintenance for Campbell units 1 and 2 in 2024 and 2025 retirement scenarios.").

Q. Please summarize your findings and recommendations.

A. Based on my review and analysis, 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 that the units' costs significantly outweigh their value. Also, the units have become less available in recent years due to unplanned outages that have decreased the level of capacity that the units can provide. The Company projects high outage rates for the units going forward in most years. Given the poor economics of the units, I recommend that Campbell 1 and 2 be considered for retirement in 2024 or 2025 after a rigorous, forward-looking assessment. In the 2021 IRP proceeding, the Company is required to submit a retirement analysis, which the Commission and parties will have an opportunity to review.

2. **The Commission should disallow rate recovery for bridge year (2021) capital costs that were identified as avoidable in the 2020 rate case, and which the Commission previously disallowed.** In the 2020 rate case (U-20697), the Commission disallowed recovery of 2021 capital and major maintenance expenditures that could be avoided if Campbell units 1 and 2 retired in 2024.[11] In the current case, the Company has again sought to recover much of the spending that was previously disallowed. These costs should continue to be disallowed because the circumstances surrounding Campbell 1 and 2 are the same as they were a year ago: The units' economics are challenging and the Campbell 1 and 2

[11] Case No. U-20697, Dec. 17, 2020, Order, pp. 77, 182.

retirement dates will be determined in the 2021 IRP case. In last year's rate case, the Commission indicated that avoidable costs should be "foregone until Consumers' upcoming 2021 IRP in which the retirement of the units will be evaluated."[12] The IRP proceeding will be ongoing when this case concludes. Thus, these previously disallowed expenditures should not be included in rate base because they remain as imprudent and unreasonable now as they were in the 2020 rate case.

3. **The Commission should disallow rate recovery for test year (2022) capital costs that the Company has identified as avoidable in this case.** The Company identified three capital projects with avoidable spending in 2022, including one project regarding compliance with the Cooling Water Intake Rule (Section 316b of the Clean Water Act).[13] The 2022 spending on these three projects of $952,000 should be disallowed in this case, for the same reasons that 2021 avoidable costs were disallowed in the last rate case.

4. **The Commission should disallow rate recovery for Steam Electric Effluent Guidelines ("SEEG") compliance costs because critical aspects of this project are too uncertain at this time.** The Company is requesting $17.3 million in 2021 and 2022 for compliance costs associated with the SEEG (also called Effluent Limitation Guidelines, or "ELGs") in this case.[14] However, there are significant uncertainties regarding the Company's SEEG compliance strategy. Among other

[12] Case No. U-20697, Dec. 17, 2020, Order, p. 182.
[13] Ex A-94 (SAH-4).
[14] Ex. A-60 (HAB-2) (projecting $1.9 million of SEEG costs in 2021, and $15.4 million in 2022).

things, the Company's rate request assumes a 2023 compliance date, but the Michigan Department of Environment, Great Lakes, and Energy ("EGLE") has issued a draft permit that would extend this compliance date to December 31, 2025. This revised timeline would significantly affect the bridge year and test year expenditures. There is additional uncertainty because, under the federal SEEG rule, Campbell units 1 and/or 2 would not require SEEG investments if they retire on or before 2028 – i.e., an issue that will be decided in the 2021 IRP case. The Company may be able to implement a less costly SEEG compliance plan if Campbell 1 and 2 retire. And there is further uncertainty because the Biden Administration is currently considering whether to begin a rulemaking process that may result in revisions to the SEEG rule. For all of these reasons, it would be premature to allow recovery of SEEG expenditures in this case. The Commission should disallow these costs.

5. **The Commission should disallow rate recovery for capital expenditures at Campbell that lack adequate support.** In the previous rate case (U-20697), the Commission disallowed recovery of several test year (2021) capital expenditures at the Campbell plant that lacked supporting documentation or suffered from major discrepancies in their cost estimates.[15] In this case, the Company is again including many of these 2021 expenditures in its rate request, but these projects still lack adequate supporting documentation. The Commission should again disallow those costs.

[15] Case No. U-20697, Dec. 17, 2020, Order, pp. 73, 78, 79, 80, 94.

In this case, the Company is also asking to recover capital expenditures in the 2022 test year that lack sufficient supporting material and/or whose cost estimates have serious inconsistencies. Because these 2022 expenditures suffer from the same shortcomings as the 2021 costs that were disallowed by the Commission in the previous case, the Commission should disallow recovery of these 2022 expenditures in this case.

6. **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.** The Company's filing identifies 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.[16] The Company should not rely on the cost estimates presented here for the Campbell 1 and 2 retirement analysis in the 2021 IRP, as that would raise questions about the robustness of the Company's evaluation.

7. **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 and involve community engagement and input. In 2018, Consumers prepared a confidential community transition plan for Karn 1 and 2. As I stated in my testimony in Case U-20697, [[[redacted],]] and that continues to

[16] Ex MEC-48 (MEC-CE-014(c), (d)).

be the case today. Although the Company intends to update its Karn transition plan, that has not yet occurred. As soon as possible, the Company should both update its plan and make it a public document.

II. CAMPBELL UNITS 1 AND 2 ARE COSTLY AND UNRELIABLE. THEY SHOULD BE CONSIDERED FOR A MID-2020S RETIREMENT.

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, which I assess by weighing energy and capacity value, with 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 expects a high outage rate to continue in future years.

Q. Please identify 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.[17]

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) estimate, which calculates the difference between MISO energy and ancillary service revenues and

[17] In last year's rate case, I used this same approach to compute the Campbell units' net economic value. See Case No. U-20697, Comings Direct, 8 TR 3894-3905. This approach is also consistent with that taken by the Company in Case No. U-20134. In Case No. U-20134, the Company stated that a generating unit's "total net value to customers" can be determined by considering net energy value, capacity value, and fixed costs. See Case No. U-20134, Ex MEC-53, p. 2.

the variable costs of operating the units (which are mainly fuel costs).[18] Thus, the NEV represents the Company's estimate of 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' historical NEVs for several years, and also provided a projection of the units' NEVs for 2021 and 2022. I used these NEV figures in calculating Campbell 1 and 2's total value. But, as discussed below, I am also skeptical of the Company's 2021 and 2022 NEV projections given the units' recent performance; I believe those projections likely overstate the units' future energy value.

<u>A. 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: the MISO capacity auction clearing price, Consumers' assumption that the future capacity value of Campbell 1 and 2 is 75 percent of the cost of new entry ("CONE"), and the cost of capacity acquired by Consumers through bilateral contracts.

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[18] Ex MEC-49, p. 2 (U20697-MEC-CE-032(b)). Revenues also include "make whole payments" and a "net generation regulation adjustment."

In its filing, Consumers reported "capacity value" for its generating units in terms of both the MISO auction price and as 75 percent of CONE, which in most years are vastly different values.[19] 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 2021, covers the 2021/2022 planning year (June 1, 2021, through May 31, 2022). 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 either by submitting a resource adequacy plan ("FRAP") or self-scheduling their capacity by bidding zero into the auction. Only a small percentage of the capacity cleared in the auction is newly procured by utilities.[20] The maximum potential 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.

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[19] Hugo Direct, p. 15, Table 2.

[20] In recent years, only between 4.7% and 3.6% of cleared capacity in the PRA was not part of a FRAP or self-scheduled. See Ex MEC-50, slide 8 (2021/2022 Planning Resource Auction (PRA) Results (Apr. 15, 2021)). Available at: https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf.

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 Zone 7 (like other MISO zones) mostly cleared at a small percentage of CONE. The 2020/21 result was a clear outlier compared to most auction results. The latest auction result of $5/MW-day, or 2 percent of CONE, is more the "norm."

Table 1: MISO PRA Zone 7 Clearing Prices ($/MW-day)[21]

MISO Planning Year	Zone 7 clearing price ($/MW-day)	% of CONE
2014/15	$16.75	7%
2015/16	$3.48	1%
2016/17	$72.00	28%
2017/18	$1.50	1%
2018/19	$10.00	4%
2019/20	$24.30	10%
2020/21	$257.30	100%
2021/22	$5.00	2%

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

A. No. The MISO capacity market (i.e., Planning Resource Auction) clearing price is a limited indicator of capacity value in that it shows whether a zone has a shortage or surplus in capacity. However, this cannot be used as the value of capacity because, typically, MISO utilities provide most or all of their own capacity needs. The 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

[21] Ex MEC-50, slides 5 and 9 (2021/2022 PRA Results); Ex MEC-51, p. 4 (MEC-CE-017-Hugo_ATT_1).

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.[22]

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

A. For future years, Consumers assumes each of its coal units has a capacity value of 75 percent of CONE.[23] This is the same capacity value assumption that Consumers presented in its 2020 rate case and 2018 IRP case. In the 2020 rate case (U-20697), the Company stated that it projected this 75 percent 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."[24] But this does not comport with the market results, where the typical clearing price has been low. Confusingly, in the current case, Company witness Hugo implied in a discovery response that the 75 percent value might be too low for large amounts of capacity.[25]

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[22] Consumers has agreed with this premise in the past. See Case No. U-20165, Clark Direct, 7 TR 952 (testifying that "the results of the MISO PRA do not represent reliable capacity values to replace the Medium Four [coal units]. 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 uncertainty of load growth and the historically lumpy nature in which capacity additions occur in the utility industry."). The "Medium Four" are Campbell units 1 and 2 and Karn units 1 and 2.
[23] Ex MEC-51, p. 2 (MEC-CE-017).
[24] Ex MEC-51, p. 6 (Case No. U-20697, discovery response U20697-MEC-CE-033(c)).
[25] Ex MEC-51, p. 2 (MEC-CE-017(d)). The discovery response does not provide any factual basis for the suggestion that capacity value could be even higher than 75% of CONE.

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. MISO has conducted a Planning Resource Auction annually since 2013, and there was a high clearing price for MISO Zone 7 in only one of those auctions: in the last year's auction (for the 2020/21 planning year) the clearing price for MISO 7 was CONE. The clearing price in the April 2021 auction (for the 2021/21 planning year) – $5 per MW-day, 2 percent of CONE – is more of a typical result.

In my testimony in the 2020 rate case, prior to the latest 2021/22 auction, I discussed several reasons why the high auction result for 2020/21 was an anomaly and thus unlikely to recur—including the underestimate of imported capacity and available generation in Zone 7.[26] One reason that this year's auction price was once again low is that the capacity import limit (CIL) for MISO Zone 7 has increased substantially. The CIL represents the amount of capacity that Zone 7 can import from the rest of MISO. Over the past year, the CIL for Zone 7 increased from 3,200 MW to 4,888 MW—an increase of more than 50 percent.[27] This increase in CIL reduced the local clearing requirement (LCR) that was needed from generation in Zone 7, thus putting less pressure on the region to provide its own capacity. In her testimony, Company witness Rose noted a shortage of 123.2 ZRCs in Zone 7 in the 2020/21 auction.[28] But in the most recent auction, MISO Zone 7 had a surplus of 1,839.3 ZRCs.[29] Although the Company has expressed concern about high clearing

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[26] Case No. U-20697, Comings Direct, 8 TR 3900-02.
[27] Ex MEC-50, slide 5 (2021/2022 PRA Results); MISO 2020/2021 PRA Results, slide 7. Available at: https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf.
[28] Rose Direct, p. 25 ("21,727.5 ZRCs were offered and cleared from Zone 7 versus an LCR of 21,850.7 ZRCs").
[29] Ex. MEC-50, slide 7 (2021/22 PRA Results) (21,549.4 ZRCs offered and cleared, and an LCR of 19,710.1 ZRCs).

prices in the MISO capacity market, and cited in support of Consumers' generation spending,[30] the 2020 PRA result is unlikely to recur in the near future.

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 or 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.[31] 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.[32]

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

A. In this case as in the previous rate case, I assumed 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 several times higher than the typical MISO clearing price.

[30] See Rose Direct, pp. 25-26.
[31] Case No. U-20165, Ex MEC-16, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000003107sAAA.
[32] Case No. U-20134, Ex MEC-55, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t00000031Eq3AAE; see also Case No. U-20134, Blumenstock Cross, 5 TR 1481-84.

B. Costs and Value of Campbell 1 and 2

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 estimated in Consumers' net energy values (NEVs) concept.[33] 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[34]
- Annual depreciation[35]
- Property taxes[36]
- Fixed operations and maintenance[37]

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.[38] 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. The Company provided this information in discovery.[39]

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[33] Ex MEC-52 (historical NEVs for 2015-2021, and projected NEVs for 2021-2022).
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 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.

[34] See Ex MEC-53, p. 5 (MEC-CE-662; U20963-MEC-CE-662-Coker_ATT_1); U-20697 MEC-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.

[35] *Id.*; U20697-MEC-CE-528-Hugo_Att_1.

[36] *Id.*; U20697-MEC-CE-1372-Hugo_ATT_1 through ATT_7.

[37] Ex MEC-47 (Campbell 1&2 fixed O&M); U20697 MEC-CE-1022 ATT 1.

[38] *See* Case No. U-17652, May 14, 2015, Order Approving Settlement Agreement, p. 4.

[39] Ex MEC-53, pp. 3-5 (U20963-MEC-CE-662-Coker_ATT_1).

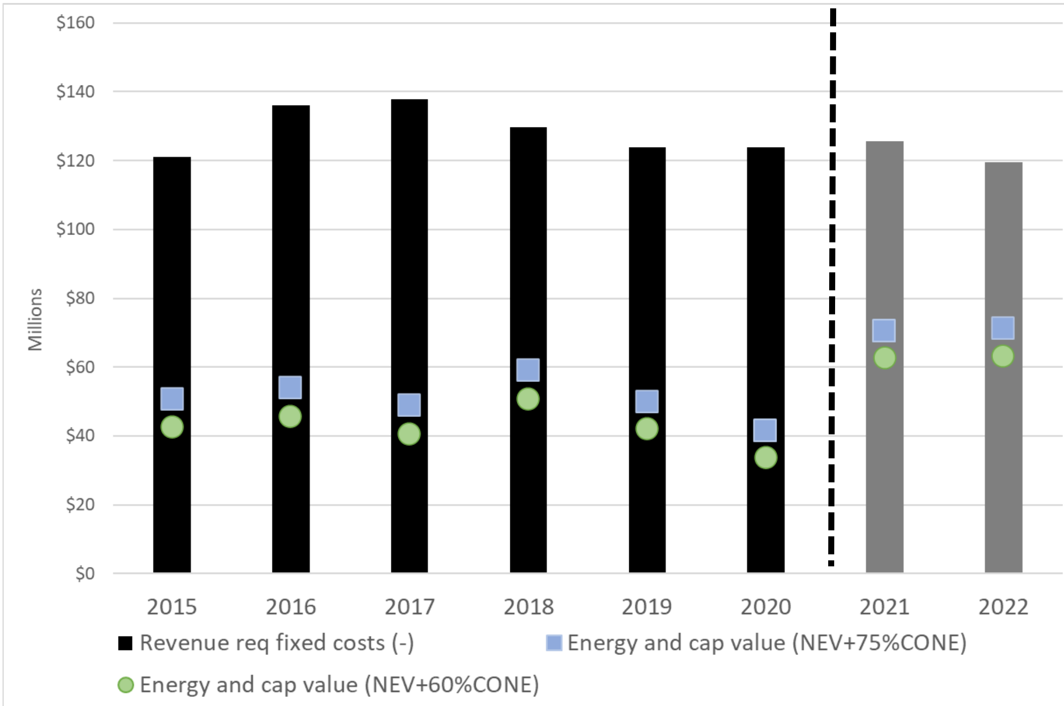
Q. How do the costs of Campbell units 1 and 2 compare to their energy and capacity value?

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 continue to do so in 2021 and 2022. This is true even if we assume the Company's high capacity value of 75 percent of CONE. This is also true even though, as I explain further below in Section II.B, Consumers' NEV projections for 2021-22 are likely inflated.

Figure 1 below shows the fixed cost revenue requirements compared to the total value provided by the units—assuming two different capacity values: 60 percent of CONE (circles), and 75 percent of CONE (squares).[40] Consumers did not provide revenue requirements separately by unit, and thus the costs and values of the two units are combined in my analysis.[41]

[40] I translated MISO CONE values from planning year into calendar year; for instance, the 2021 calendar year value is 5/12*2020/2021 price + 7/12*2021/2022 price. Capacity values of 60% and 75% of CONE use the Zone 7 CONE value for the corresponding planning year. See also U20697 MEC-CE-033-Hugo_ATT_1.
[41] See Ex MEC-53, p. 3 (U20963-MEC-CE-662-Coker_ATT_1).

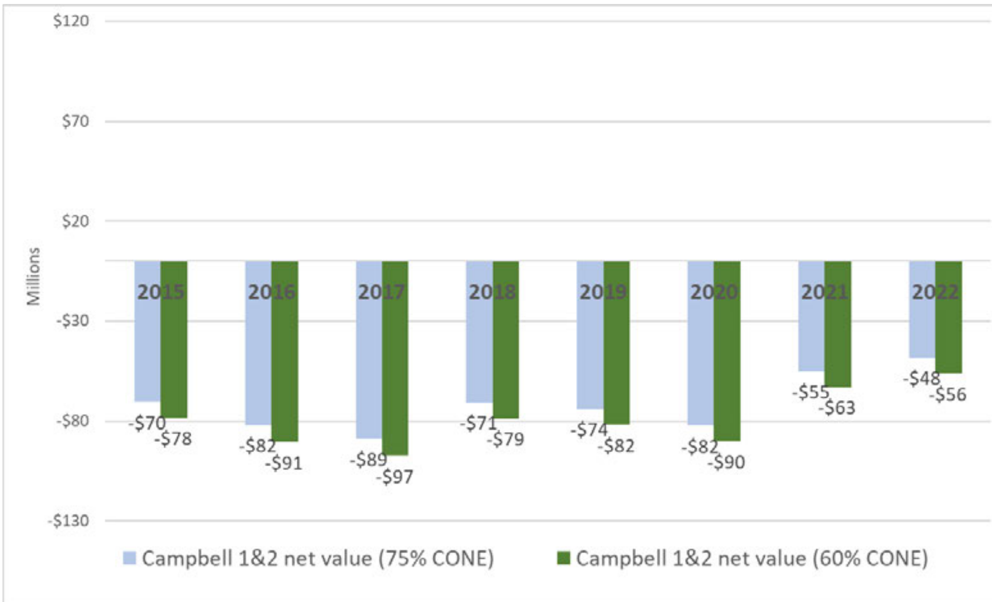
Figure 1: Comparison of Costs, Energy and Capacity Value of Campbell units 1 and 2



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)

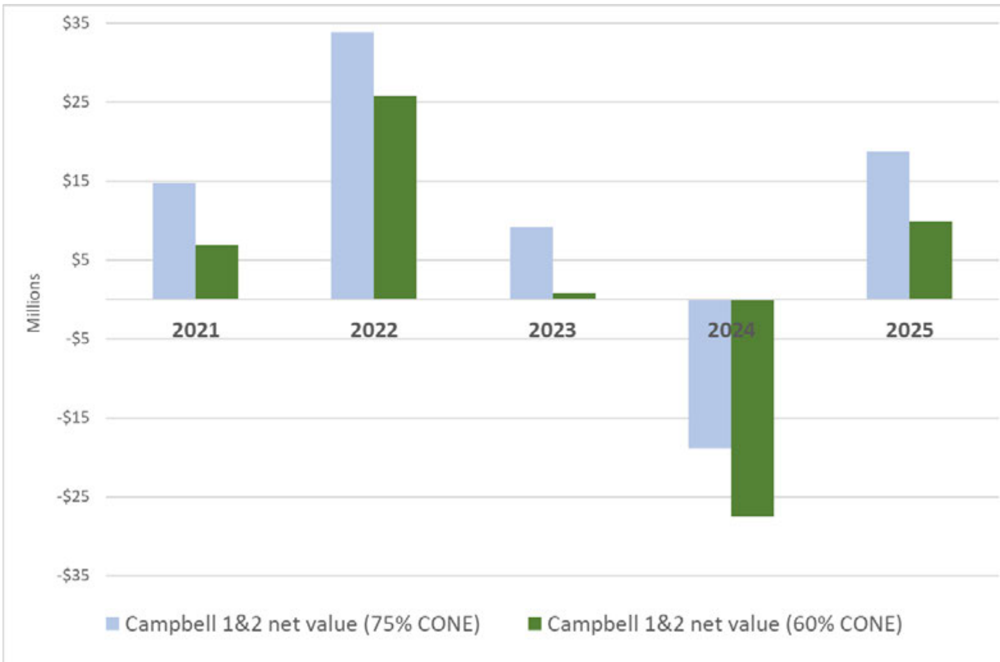


As Figure 2 shows, the energy and capacity value of Campbell 1 and 2 is far outweighed by the units' fixed costs. This is true regardless of whether one assumes a capacity value of 60% or 75% of CONE. By this measure, the "net" value of the units is between -$48 million to -$97 million annually; but the true value in 2021 and 2022 is likely lower given that the NEV projections in those years are overly optimistic (as explained below). Regardless, in each year Campbell 1 and 2 are costing the Company's customers substantially.

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, rather than revenue requirements (which were not available after 2022). 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.[42] For the years after 2022, for which the Company did not have an NEV projection, I used the historical average of actual NEVs for 2015 through 2020 and adjusted for inflation. The net values are shown below for Campbell 1 and 2 combined for 2021 through 2025 in Figure 3.

Figure 3: Net Value of Campbell units 1 and 2 (Annual Spending)[43]



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

Neither the revenue requirement comparison (Figures 1 and 2) nor the as-spent comparison (Figure 3) are meant to take the place of a rigorous, forward-looking economic assessment.

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[42] Consumers has previously 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. See Case No. U-20697, Ex MEC-80 (U20697-MEC-CE-535).

[43] The projected capital spending is from U20963-MEC-CE-013_ATT_45. Property taxes for 2023-2025 were estimated using the 5-year compound annual growth rate (CAGR) from 2017-2022 values provided in U20963-MEC-CE-662-Coker_ATT_1 (Ex MEC-53). Capacity value was escalated at 2% per year. The projected NEVs for 2021 and 2022 were those provided by the Company in this case. The Company did not provide an NEV projection for 2023-25; for those

I do not expect the Company to decide to retire one or both units based only on their recent performance. The revenue requirements comparison (Figure 2) is the more meaningful one because these are the costs actually paid by ratepayers, and this comparison shows that the units' costs exceed their value.

I recognize that the costs included in revenue requirements 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. The annual spending comparison is limited by only looking at costs (as-spent) and value through 2025. 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.

Q. Do the projected values for 2021 and 2022—for both revenue requirement and as-spent comparisons—likely overstate the economic value of Campbell 1 and 2?

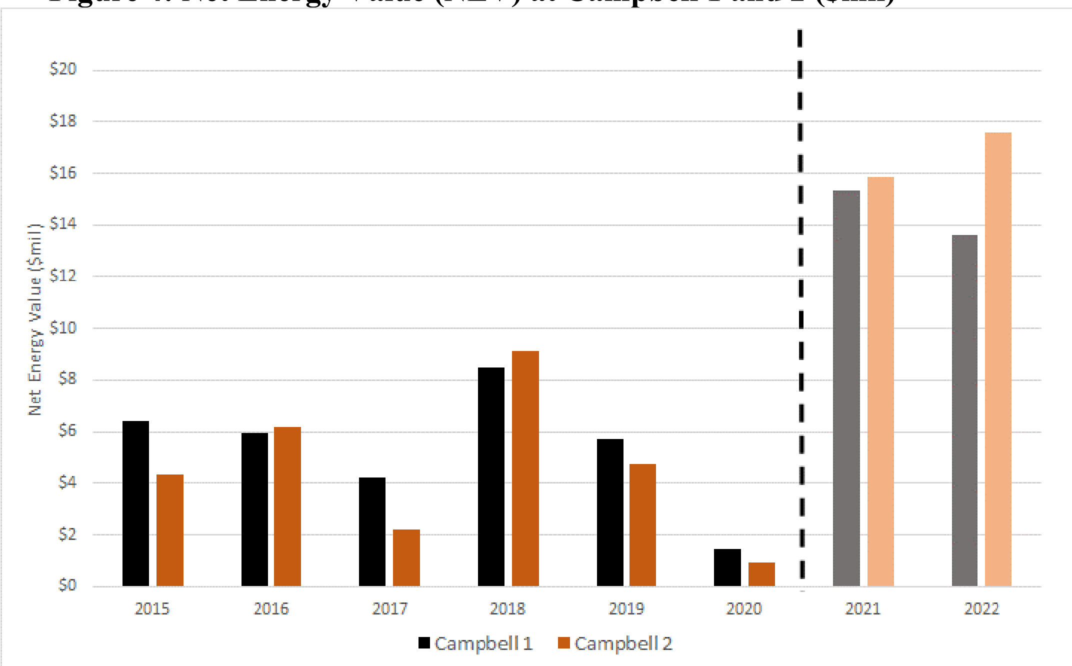
A. Yes. I did not adjust the Company's net energy value (NEV) projection for 2021 and 2022 but I believe these values are likely inflated. The Company is projecting a drastic increase in these units' NEV in 2021 and 2022 that does not comport with their historical performance—as shown below in Figure 4. The units' performance has been declining in the past three years. Yet, the Company expects these units to provide substantially more energy value than they have at any point in the past six years.

The Company also has a record of overestimating future NEVs. In the previous rate case, Consumers predicted a 2020 NEV $20.5 million for both units, but the actual NEV in 2020 was $2.4 million—only 12 percent of the NEV the Company had predicted for 2020

years, the projected NEV is based on the 6-year average for historical data reported from 2015-2020, adjusted for inflation by 2% per year.

materialized.[44] The NEVs presented in this case appear to be even more inflated post-2020: whereas the Company predicted a 2021 NEV of $16 million in last year's case, for the combined units, in the current case the Company has predicted roughly double that amount ($31.2 million) for 2021.[45] Although the 2020 NEVs were likely affected by lower demand and prices due to the Covid-19 pandemic, there is no reason to think that the Company's expectations for NEV in 2021 would double between now and the last case.

Figure 4: Net Energy Value (NEV) at Campbell 1 and 2 ($mil)



Q. What is contributing to the inflated 2021 and 2022 NEV projections?

A. In reviewing the Company's projections, I found that the assumed [[[redacted]

[44] Ex MEC-52.
[45] *Id.*

[redacted]]] Thus, an [[[redacted]]] would both understate the costs of operating the unit and overstate the NEV, by definition. The Company assumes an [[[redacted]]] in the NEV calculation but it predicts a [[[redacted]]] for these units—as shown below in Table 2.[46]

[[[redacted][47]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]]. As a result, the above estimates of 2021 and 2022 economic value for the units should be seen as inflated.

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[46] Ex MEC-54C (U20963-MEC-CE-1048-CONFIDENTIAL); U20963-MEC-CE-016-Hugo_CONF_ATT_3; U20963-MEC-CE-011-Hugo-ATT_1 (2nd Revised).

[47] *Id.* [[[redacted]]]

Q. Do your calculations of the Campbell units' economic value use the Company's NEV projection for 2021 and 2022?

A. Yes. Despite my skepticism about the projected NEVs for 2021 and 2022, I have used those figures in estimating the Campbell units' value. As discussed above, Figures 1 and 2 above rely entirely on NEV data provided by the Company (historical NEVs for 2015-20, projected NEVs for 2021-22). Thus, even if the Company's NEV projection were accurate, Campbell units 1 and 2 would still be costing ratepayers tens of millions of dollars each year. The illustrative calculation in Figure 3 uses the Company's NEV projections for 2021 and 2022, while using an inflation-adjusted historical average for 2023-25.

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] It is critical that this forward-looking retirement analysis take place before incurring significant and avoidable costs which will ultimately impact ratepayers. 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 avoiding those costs because they were included in rates—and these costs will become stranded. In Section III below, I discuss capital expenditures which could be avoided if the units are retired in 2024 or 2025, and, for the reasons explained, should be disallowed.

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

C. The Availability of Campbell 1 and 2

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

A. Yes. It is axiomatic that a unit cannot generate if it is unavailable. Campbell 1 and 2 have both struggled in recent years with being unavailable due to random forced outages for a high portion of hours—and this trend is likely to persist.[49] 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. The units' zonal resource credits (ZRCs) in MISO are based on unforced capacity (UCAP), which discounts a unit's capacity based on a likelihood that it will be on a forced outage.

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.[50] The Company still anticipates a high outage rate through 2025[51]—as shown in Figure 5 below. The Company expects that the units will be randomly unavailable roughly 15 percent of the time in most years. (This is in addition to planned outages, but those are typically scheduled for off-peak times and, therefore, do not affect capacity value.)

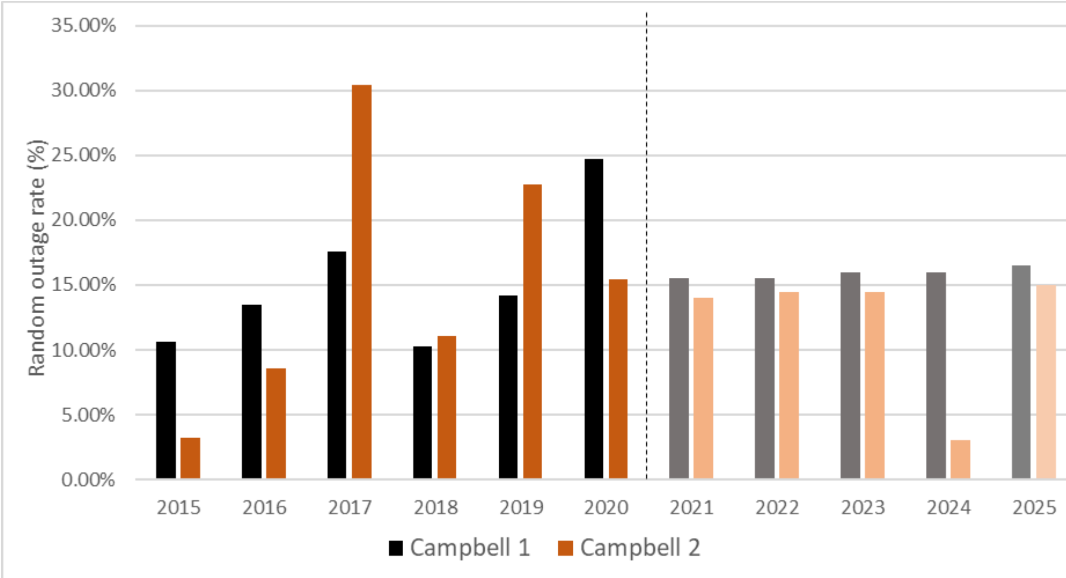
[49] Availability refers to the amount of a unit's maximum capacity that could be operated over a given time period. The capacity factor measures the actual generation of a unit as a share of its maximum capacity if it ran 100 percent of the time. By definition, the capacity factor cannot be higher than a unit's availability factor because the unit cannot generate power when it is not available.

In discovery, Consumers provided "MWh availability" – the maximum amount that could be generated when the unit is not on a planned or random (i.e. unplanned or forced) outage – and capacity factors for Campbell 1 and 2. MEC-CE-011-Hugo-ATT_1 (2nd Revised).

[50] *Id.*

[51] *Id.*

Figure 5: Random Outage Rates for Campbell units 1 and 2[52]



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

A. Yes. The Company had projected much lower random outage rates for 2019: 10.5 percent for Campbell 1 and 7.5 percent for Campbell 2.[53] 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, recent random outage rates have been much higher, with 2020 rates of 25 and 15 percent for Campbell 1 and 2, respectively.[54] Put differently, Campbell 1 and 2 were forced out of operation at least twice as much as assumed in the Company's last retirement analysis. An updated retirement analysis should include realistic assumptions about the units' performance.

[52] Ex MEC-55 (random outage rates provided in MEC-CE-010_Hugo_Att_1 2nd Revised and MEC-CE-011-Hugo-ATT_1 2nd Revised).
[53] Case No. U-20165, Ex MEC-60 (20165-MEC-CE-18 +ROR 2018 IRP).
[54] See Ex MEC-55.

Q. Has the Company's outlook for Campbell units 1 and 2's level of credited capacity recently decreased?

A. Yes. The ZRCs have decreased and are lower than what the Company projected in the 2020 rate case. All else equal, that means that the units are now expected to provide lower capacity value than before. As shown below in Table 3, the Company had previously credited Campbell unit 2 with 331 ZRCs in 2020 in the previous case, but in the current case reports 305 ZRCs for the unit—a decrease of 8 percent of credited capacity.[55] Campbell unit 1 credited capacity only decreased by 1 percent but the Company anticipates a 5 percent decrease in 2021 (relative to what it expected in the 2020 rate case).

Table 3: Zonal Resource Credits from Campbell units 1 and 2 (MW)[56]

	2020	2021	2022
Campbell 1 (2020 case)	254	254	254
Campbell 1 (2021 case)	251	240	243
% change	*-1%*	*-5%*	*-4%*
Campbell 2 (2020 case)	331	331	331
Campbell 2 (2021 case)	305	311	319
% change	*-8%*	*-6%*	*-4%*

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

A. The continued unavailability and decrease in ZRCs at the 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. In the 2021 IRP case, the Company is required to submit a retirement assessment for the IRP being filed later this month. The ultimate retirement decision for Campbell 1 and 2 should be based on a robust, forward-looking assessment of the units' value relative to replacement options. That

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[55] U20697-033-Hugo_ATT_1; U20963-MEC-CE-010_Hugo_Att_1 (2nd Revised).
[56] *Id.*

assessment should incorporate more realistic underlying assumptions as to the units' performance—particularly on the net energy value—than what the Company has assumed in this case.

III. <u>COST RECOVERY OF CERTAIN CAPITAL PROJECTS AT THE CAMPBELL UNITS SHOULD BE DISALLOWED.</u>

Q. Please summarize your evaluation of capital expenditures at the Campbell units.

A. In reviewing the Company's proposed capital expenditures for the Campbell units, I have found that many of these costs not been justified by the Company or represent an imprudent, avoidable expense. I recommend that the Commission disallow rate recovery of these expenditures, which total $13.9 million in the 2021 bridge year and $25.7 million in the 2022 test year. My recommended disallowances include several 2021 expenditures that were previously disallowed by the Commission in Case No. U-20697, as well as several 2022 expenditures that Consumers first proposed in this case. Specifically, I am recommending that the Commission disallow the following capital expenditures (shown in Exhibit MEC-56):

1. <u>Avoidable expenditures disallowed in Case U-20697</u>. In last year's rate case, the Commission disallowed several capital expenditures planned for 2021 that could be avoided if Campbell units 1 and 2 retired in 2024. In this case, Consumers is again seeking rate recovery of many of these avoidable expenditures. These costs should again be disallowed.

2. <u>Avoidable expenditures identified by the Company in this case</u>. Consumers requests recovery of several 2022 test year expenditures that it acknowledges

could be avoided if Campbell 1 and 2 retire in 2024 or 2025. As in last year's rate case, such avoidable costs should be disallowed.

3. Steam Electric Effluent Guidelines ("SEEG") compliance costs. Consumers seeks to recover $17.3 million in 2021-22 for SEEG compliance costs. As explained below, these costs are too uncertain to be included in rate base at this time.

4. Capital expenditures planned for 2021 and 2022 that do not have adequate supporting documentation. The Commission disallowed rate recovery for many of these 2021 expenditures in Case U-20697 because the projects lacked adequate support. To the extent that such projects still lack support, those costs should again be disallowed. And 2022 capital expenditures that lack support, or whose cost estimates suffer from major discrepancies, should likewise be disallowed.

A. Avoidable capital expenditures disallowed in Case U-20697

Q. Please describe the Company's obligation to identify "avoidable" costs in its rate cases.

A. As discussed above in Section I, the settlement agreement from the 2018 IRP case requires Consumers to submit a Campbell 1 and 2 retirement analysis with its next IRP (to be filed by the end of June 2021).[57] The settlement also includes a specific requirement that applies to rate cases filed prior to this next IRP: Consumers must identify "avoidable capital expenditures (environmental and non-environmental) and avoidable major maintenance for

[57] Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, Par 4.

Campbell units 1 and 2 in 2024 and 2025 retirement scenarios."[58] Thus, if a capital or major maintenance expenditure could be avoided if the Campbell units retire by 2024 (or 2025), such expenditure is avoidable. The Company had this obligation in last year's rate case, and the obligation applies to this case as well.

Q. How does the Company classify capital and major maintenance projects?

A. In discovery, the Company identified three main categories of "approval criteria" for capital and major maintenance projects: 1) "safety/compliance/regulatory," 2) "equipment condition," and 3) "economic and equipment condition."[59] The Company describes "safety/compliance/regulatory" projects as those deemed by Consumers to be required for safe and compliant operations, and "equipment condition" projects are intended to achieve the original condition of the equipment.[60] "Economic" projects are intended to improve unit performance and thereby provide savings to ratepayers; these projects are evaluated by the Company using its own financial models of the internal rate of return (IRR) and present value ratio (PVR) analyses to assess whether there is net savings from pursuing the project.[61]

Q. How does the Company identify what spending is avoidable?

A. The precise method is unclear. Consumers suggested that they determine whether projects are avoidable:

> … based on the philosophy of running the units in a safe, regulatory

[58] Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, Par 6.
[59] U20963-MEC-CE-637_ATT_1. See also Case No. U-20697, Ex MEC-82 (discovery response describing the Company's approval criteria categories), available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Ei13JAAR (PDF pp. 214-15).
[60] See *id.*
[61] See *id.*; see also Hugo Direct, pp. 35-36.

> compliant manner through end of life and allowing for reasonable decrease in availability and reliability.[62]

Thus, the designation of avoidability appears to be largely a judgment call on the part of the Company. And the Company's designations have not been consistent over time. There are seven capital and major maintenance projects planned for 2022 that were designated as avoidable in last year's rate case, but which the Company designated as unavoidable in this case.[63]

Q. Please explain the categories of avoidable spending that you have evaluated in this case.

A. There are two categories of avoidable spending being sought for recovery in this case:

1. Capital expenditures in 2021 that were previously identified as avoidable and disallowed by the Commission in the previous rate case. These disallowed expenditures included one capital project at Campbell unit 2 – no. 5462 (SAH Replace baskets and seals) – that I identified after review of the Company's IRR analysis.[64]

2. Capital expenditures in 2022 that Consumers has designated as avoidable.

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[62] Ex MEC-57, p. 5 (MEC-CE-023(a)).

[63] For example, in Case No. U-20697, Consumers identified the following 2022 capital expenditures as avoidable: project nos. 9194 (JHC1 PJFF Filter Bag Replacement), 9650 (JHC1 Major Motor and Pump Overhauls), and 9653 (JHC1 Balance of Plant Equipment Replacements). Case No. U-20697, Ex MEC-85, pp. 1, 3 (information provided in U20697-MEC-CE-545-Hugo_Att_1).

In this case, however, Consumers claims these same projects are unavoidable. When asked in discovery why these expenditures were unavoidable, Consumers did not provide any information shedding light on their redesignation from avoidable to unavoidable. See Ex MEC-57, pp. 8-9 (MEC-CE-647(a)-(c)).

[64] Case No. U-20697, Comings Direct, 8 TR 3921-22.

Note that the Company did not identify any major maintenance costs as avoidable in this case.

Q. In the 2020 rate case (U-20697), did the Commission disallow capital and major maintenance spending Campbell unit that could be avoided by Campbell 1 and 2's retirement in 2024 or 2025?

A. Yes. In last year's rate case, I recommended disallowing rate recovery of capital and major maintenance costs at Campbell that could be avoided with a 2024 or 2025 retirement.[65] The ALJ supported that recommendation, and the Commission ultimately adopted it. The Commission thus disallowed 2021 spending for several avoidable capital and major maintenance expenditures.[66]

Q. Is the Company still seeking recovery for 2021 capital spending at Campbell units 1 and 2 that was previously disallowed for being avoidable?

A. Yes. The Company is seeking recovery for 2021 spending on two capital projects that it previously designated as avoidable, as well as one project which I identified as avoidable after reviewing discovery.[67]

Q. Please explain why 2021 spending on capital projects 5573 and 5577 should be disallowed once again in this case.

A. In the previous rate case, these two projects, whose projected cost in 2021 is $982,000,[68] were disallowed because they are avoidable under a Campbell 1 and 2 2024 retirement

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[65] Case No. U-20697, Comings Direct, 8 TR 3917-22.
[66] Case No. U-20697, Dec. 17, 2020, Order, pp. 77, 182.
[67] Specifically, Consumers is seeking rate recovery of the following 2021 capital expenditures that were found to be avoidable under a 2024 retirement scenario: projects 5462 (JHC2 SAH Baskets and Seals), 5573 (JHC 2 Overhaul CCWP & Motors), and 5577 (Overhaul JHC2 FD Fan Motors).
[68] The projected 2021 cost of these two projects has not changed since last year's case.

scenario.[69] Although the Company is yet again requesting recovery of these costs, these costs should continue to be disallowed because the circumstances surrounding Campbell 1 and 2 are the same as they were in last year's rate case. As I explained above in Section II.B, the net economic value of Campbell 1 and 2 is negative, meaning that these units are costing ratepayers tens of millions of dollars each year. Also, as was true in last year's case, the appropriate retirement dates for Campbell 1 and 2 is an open question – one that will be determined in the IRP proceeding (which will remain pending when this rate case ends). The Commission should continue to disallow recovery of these costs because they are as imprudent now as they were in the 2020 rate case. These recommended disallowances, totaling $3,717,000, are shown on page 1 of Exhibit MEC-56.[70]

Q. Did the Company identify any 2021 capital expenditures as avoidable in this case?

A. No. In discovery, MNSC asked the Company to identify any 2021 projects that could have been avoided under a 2024 or 2025 retirement scenario. The Company did not identify any such projects and took the position that all 2021 bridge year expenditures are unavoidable.[71] The Company claims that due to the timing of the case, including a likely December 2021 Commission order, it cannot avoid any spending in 2021 because it will be too late.[72]

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[69] U-20697, Dec. 17, 2020, Order, pp. 75, 77.
[70] These 2021 capital expenditures that I recommend disallowing here are reflected in the Company's exhibits:
-- project 5462 is identified in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 8, line 2;
-- The other two expenditures are not separately identified, but are reflected in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 2, line 1, column (f).
[71] Ex MEC-57, p. 14 (MEC-CE-986).
[72] *Id.*

I disagree with the Company's position. In the 2020 rate case the Company acknowledged that the projects discussed above were avoidable, and the Commission subsequently disallowed them. Despite this, and the fact that the future of Campbell 1 and 2 has still not been determined, spending in 2021 could have been avoided—the Company chose (or is choosing) not to avoid it. Therefore, regardless of the Company's change in position on this 2021 spending, the Commission should uphold the disallowance of these costs from the previous case.

Q. Please explain why Project 5462 – "JHC2 SAH Baskets and Seals Replacement" -- should be disallowed once again in this case.

A. This project should again be disallowed for several reasons, including its avoidability under a 2024 retirement scenario, and because the support for this project is [[redacted]]. Project 5462 at Campbell unit 2 was designated as an "economic" project by Consumers in the previous and current rate case.[73] In the previous case, I determined that this project was avoidable under a 2024 or 2025 retirement scenario.[74] I argued that the project should be disallowed. because the economic assessment for this project (i.e., the IRR) showed that the [[redacted]

[73] See Ex MEC-59, p. 1 (designating project 5462 as "Economic & Equipment Condition"). Consumers has confirmed in discovery that it did not change the approval criteria for any of the Campbell capital projects that were disallowed in last year's case.
Because information about the Campbell units' projected expenditures was included in several different discovery attachments, I consolidated this information into Exhibit MEC-58, which:
-- lists the approval criteria for these expenditures (from MEC-CE-637_ATT_1);
-- identifies projects planned for the 2022 test year that Consumers has acknowledged could be deferred beyond the test year (from MEC-CE-648-ATT_1); and
-- identifies supporting documents for these planned expenditures (provided by Consumers in MEC-CE-013_ATT_44, MEC-CE-648-ATT_1, MEC-CE-026_ATT_1 (Revised), ST-CE-076_ATT_1, and "Supplemental List of Scope Documents," (served on May 19, 2021).
[74] Case No. U-20697, Comings Direct, 8 TR 3921-22.

[redacted]]].[75] The Commission agreed that the project was avoidable and disallowed these costs.[76]

In the current case, Consumers has increased the project's estimated cost by $310,000, to $2.735 million.[77] But despite this 13% increase in the project's costs, the Company has not updated the economic assessment (i.e., the IRR).[78] That assessment appears to be [[[redacted]]] The Company did not attempt to address this problem before again requesting rate recovery for this expenditure.

Consumers claims that this project is needs to be performed in 2021, stating that "the cold end radial seals are in very poor condition. Erosion from sootblower and fly ash has caused the seals to degrade to a point where large sections are missing, bent and worn, and are about 50% efficient or less."[80] But the project charter, which was finalized over three years

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[75] These issues were discussed in the confidential version of my testimony. See Case No. U-20697, Comings Direct, 8 TR 5138-39.
[76] See Case No. U-20697, Dec. 17, 2020, Order, p 77 (noting that "the MEC Coalition presented convincing evidence that these investments [including project 5462] are potentially avoidable"); see also Case No. U-20697, Oct. 22, 2020, Proposal for Decision, p. 120 ("This PFD also finds persuasive the MEC group's contention that the basket and seal replacement project is avoidable.").
[77] Ex MEC-59, p. 3 (MEC-CE-642(a)).
[78] Ex MEC-59, p. 3 (MEC-CE-642(b)).
[79] Ex MEC-60C (U20697-MEC-CE-1027(a), (b), (d)-CONF). This discovery response was first provided in last year's case, but Consumers reproduced it in response to request MEC-CE-008.
[80] Ex MEC-59, p. 1 (MEC-CE-022).

ago (and has never been updated),[81] stated similar reasoning that "baskets and seals are in poor condition with fouling and significant erosion."[82] Despite the Company making a similar argument in the 2020 rate case, the project was disallowed.[83] The myriad reasons for disallowing the project in the previous case remain true here—there are no substantive changes to the project or its justification. Meanwhile, the estimated cost has increased without supporting documentation. Thus, this $2.735 million expenditure should be disallowed in this case.

B. <u>Avoidable capital expenditures in the 2022 test year</u>

Q. Has the Company identified any 2022 expenditures as avoidable in this case?

A. Yes. The Company has designated three capital projects, with $952,000 in 2022 spending, as avoidable under a 2024 or 2025 retirement scenario.[84] These Company-identified avoidable costs —include a project aimed at complying with the Clean Water Intake Rule (Section 316b of the Clean Water Act). This project has $500,000 of spending in the 2022 test year, followed by more than $37 million in additional spending in 2023 and 2024.[85]

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

[81] Ex MEC-59, p. 3 (MEC-CE-642(c), (d)) (confirming that the project charter is the one dated Feb. 8, 2018, and that the Company has provided the most up-to-date versions of supporting documents).
[82] U-20963-MEC-CE-013_ATT_8 (dated February 8, 2018).
[83] U-20697 Commission Order, December 17, 2020, p.77.
[84] Specifically, projects 5589 (JHC1 SH Outlet Pendant Tube Panel Replacements), 5665 (JHC1 Ashpit Replacement), and 5538 (JHC 1&2 - 316B Deep Water Intake) have been identified as avoidable. U-20963-MEC-CE-648-ATT_1.
[85] See Ex MEC-58, p. 1.

A. No. For similar reasons as other avoidable projects discussed previously, these projects should be disallowed in this case.[86] 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 or 2025, and because these expenditures could be avoided with a 2024 or 2025 retirement, recovery of these costs should be disallowed as unreasonable and imprudent. Disallowing these costs is consistent with the Order in last year's rate case, where the Commission disallowed avoidable capital and major maintenance costs.[87]

Exhibit MEC-56 shows those projects with 2022 spending that should be disallowed because the expenditures are avoidable. In total, these avoidable projects represent $0.95 million in capital spending in 2022.[88]

C. Steam Electric Effluent Guidelines (SEEG) compliance costs

Q. Please briefly describe the Steam Electric Effluent Guidelines, and their relevance to the Campbell units.

A. The Steam Electric Effluent Guidelines (also called Effluent Limitation Guidelines, or "ELGs") establish technology-based effluent limits for steam electric generating units like

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[86] Project 5665 (JHC1 SH Outlet Pendant Tube Panel Replacements) also lacks supporting documentation, which is another category of disallowances that I will address later in my testimony.
[87] Case No. U-20697, Dec. 17, 2020, Order, pp. 77, 182.
[88] These 2022 capital expenditures that I recommend disallowing here are reflected in:
-- Exhibit A-12 (SAH-3), Schedule B-5.2, p. 2, line 1, column (j) (projects 5589 and 5665);
-- Exhibit A-12 (SAH-3), Schedule B-5.2, p. 3, line 99 (project 5538).
These avoidable expenditures are also identified in Exhibit A-94 (SAH-4), and project 5538 (JHC 1&2 - 316B Deep Water Intake) is also identified in Exhibit A-59 (HAB-1).

those at the Campbell plant. EPA promulgated the SEEG Rule in 2015.[89] These must be included in Clean Water Act permits (i.e., National Pollutant Discharge Elimination System or "NPDES" permits). One of the waste streams addressed by the SEEG Rule is bottom ash transport water.[90] EPA determined that the Rule, including this zero-discharge standard for bottom ash transport water, will improve groundwater and surface water quality and reduce impacts to human health and wildlife.[91] The 2015 Rule established that a compliance deadline for bottom ash transport water be no later than December 31, 2023.[92]

In October 2020, EPA revised the SEEG Rule. The 2020 revised rule made several changes relevant to discharges of bottom as transport water.[93] First, under the 2020 rule, a generating unit's compliance date can be pushed back by two years – to as late as December 31, 2025.[94] Second, if a generator commits to cease burning coal by December 31, 2028, the rule does not require the implementation of an SEEG-compliant technology.[95] Third, the revised rule weakened the zero-discharge standard for bottom ash transport water

[89] See U.S. EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; 80 Fed. Reg. 67838 (Nov. 3, 2015).
[90] In the 2015 SEEG Rule, EPA explained: "Bottom ash consists of heavier ash particles that are not entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot bottom ash is quenched in a water-filled hopper. . . . Most plants use water to transport (sluice) the bottom ash from the hopper to an impoundment or dewatering bins. The ash sent to a dewatering bin is separated from the transport water and then disposed. For both of these systems, the water used to transport the bottom ash to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems, after the bottom ash has settled to the bottom." 80 Fed. Reg. at 67846.
[91] *See* 80 Fed. Reg. at 67873-77.
[92] 80 Fed Reg. at 67896 (40 C.F.R. § 423.13(k)(1)(i)).
[93] U.S. EPA, Steam Electric Reconsideration Rule, 85 Fed. Reg. 64650 (Oct. 13, 2020).
[94] 40 C.F.R. § 423.13(k)(1)(i).
[95] See 40 C.F.R. § 423.19(f) (establishing "[r]equirements for units that will achieve permanent cessation of coal combustion by December 31, 2028").

transport. Under the revised rule, some discharge of pollutants in bottom ash transport water is authorized for certain specified activities.[96]

Although the current NPDES permit for Campbell includes a 2023 compliance deadline for bottom ash transport water, there is a strong chance that this deadline will be extended to 2025. In January 2021, Consumers submitted a request to the Michigan Department of Environment, Great Lakes, and Energy (EGLE) asking that the compliance deadline be changed to December 31, 2025.[97] EGLE subsequently issued a draft permit that, if finalized, would grant Consumers' request and extend the compliance deadline to 2025.[98]

The SEEG rule, including its substantive requirements and compliance deadline, could soon be subject to further changes. In January, the Biden Administration placed the 2020 rule revision under review.[99] It appears that U.S. EPA may reach a decision as soon as next month: in a federal court case involving challenges to the 2020 rule, U.S. EPA represented that it would decide by July 24, 2021, "whether to initiate a new rulemaking to revise the [2020 rule]."[100]

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[96] 40 C.F.R. § 423.13(k)(2)(i)(A). How large a volume may be discharged for such activities is left to the discretion of the permitting authority on a case-by-case basis, but may not exceed 10 percent of the primary bottom ash system volume on a monthly basis, using a rolling average. 40 C.F.R. § 423.13(k)(2)(i)(B).
[97] Ex MEC-61, p. 1 (Letter from Consumers Energy Company to EGLE Re: J.H. Campbell Complex NPDES Permit No. MI0001422, produced as U20963-ST-CE-454-Breining_ATT_1).
[98] See Ex MEC-62, p. 15 (ST-CE-454(a)); see also Ex MEC-63, p. 14 (Draft NPDES Permit Modification for J.H. Campbell Plant, Permit No. MI0001422).
[99] Fact Sheet: List of Agency Actions for Review (Jan. 20, 2021) https://www.whitehouse.gov/briefing-room/statements-releases/2021/01/20/fact-sheet-list-of-agency-actions-for-review/ (listing the October 13, 2020 "Steam Electric Reconsideration Rule" as an EPA rule under review).
[100] Ex MEC-64 (*Appalachian Voices v. U.S. EPA*, Case No. 20-2187 (L), Doc. 60, Unopposed Motion to Hold Merits Briefing Schedule in Abeyance Pars 8-9 (May 25, 2021) (4th Cir.); *id.*, Doc. 61, Order Extending Abeyance (June 1, 2021)).

Q. Please describe the Company's request for SEEG compliance costs.

A. According to the Company's filing, Consumers plans to spend $26 million on SEEG compliance at the three Campbell units (project 5523) over the next three years: including $1.9 million in the 2021 bridge year, and $15.4 million in the 2022 test year.[101] This capital project would involve the installation of a "high recycle rate closed loop system" intended to comply with the 2020 revised rule,[102] but which would not meet the zero-discharge standard previously established by the 2015 Rule.[103] Consumers' compliance strategy would thus allow for the discharge of some bottom ash transport water. Put differently, the Company's compliance plan seems to assume that U.S. EPA will not restore the zero-discharge standard. As discussed below, other aspects of the SEEG compliance strategy remain uncertain, including the project timeline and ultimate cost.

Q. Should the Commission approve Consumers' request for rate recovery of $17.3 million of SEEG compliance costs?

A. No. There is too much uncertainty regarding major aspects of the regulation and of the specific project to grant recovery of SEEG compliance costs in this case. The Commission has previously held that when plans requiring expenditures in the test year are uncertain, the Commission will not approve rate recovery of such expenditures.[104] Indeed, such

[101] Ex A-60 (HAB-2); see also Ex MEC-62, p. 8 (MEC-CE-652(a)); Ex MEC-58, p. 1 (projected capital expenditures at the Campbell plant, 2021-25).
[102] See Breining Direct, pp. 11, 12-13; see also Ex MEC-62, p. 3 (MEC-CE-033(g)) ("The proposed system will utilize the SEEG provision that allows discharge up to 10% of the primary active wetted BA system volume on a 30-day rolling average.").
[103] Ex MEC-62, p. 12 (MEC-CE-655(b) – Supplemental) ("A zero liquid discharge system is <u>not</u> being implemented.").
[104] See, e.g., Case No. U-20165, May 7, 2020, Order, p. 58 (disallowing costs where "it is uncertain that the company's requested expenditures will be used as indicated in 2020"), p. 69 (disallowing recovery of costs for a coal ash basin closure project due to multiple uncertainties).

concerns prompted the Commission to disallow rate recovery of SEEG costs in last year's rate case.[105] For similar reasons, the Commission disallowed recovery of Section 316(b) compliance costs, concluding that the "project is premature for inclusion in rate base."[106]

Here, there are significant uncertainties regarding several aspects of the SEEG compliance project. First, although the Company's rate request assumes that compliance needs to be achieved by 2023, the Company has asked EGLE to extend this compliance deadline to 2025. And as noted above, EGLE has issued a draft permit that would grant Consumers' request. If the draft permit is finalized, the compliance date for the Campbell units will be December 31, 2025 (unless the Company decides to retire the units by 2028).[107] In the event this extension is granted, the spending timeline would be significantly delayed, as shown below in Figure 7.

[105] Case No. U-20697, Dec. 17, 2020, Order, p. 74 (disallowing SEEG costs as premature when contemplating a 2023 compliance deadline).
[106] Case No. U-20697, Dec. 17, 2020, Order, p. 93.
[107] Ex MEC-62, p. 10 (MEC-CE-653(a), (b)).

Figure 6: Campbell SEEG Costs - 2023 vs. 2025 Compliance[108]

Second, there are uncertainties regarding the design and estimated cost of the SEEG compliance project. In discovery, Consumers was asked if it had evaluated whether a smaller SEEG system could be implemented if Campbell 1 and 2 retired by or before 2028. In a response stating that it could not quantify any cost savings from those units' retirement, Consumers claimed that its SEEG estimates "are order of magnitude cost estimates and are not detailed enough to be able to quantify the potential cost savings."[109] Additionally, although the Company hired a contractor to prepare a conceptual design for its SEEG compliance plan, apparently that design has not been completed.[110]

Third, the Company's compliance strategy assumes that the requirements of the 2020 rule remains unchanged. But as mentioned above, U.S. EPA is considering whether to revise

[108] WP-HAB-1; U20963-ST-CE-454-Breining_ATT_2.
[109] MEC-62, p. 11 (MEC-CE-654(a)).
[110] See MEC-62, pp. 2, 12, 14 (MEC-CE-033(a)) (anticipating completion of the design by mid-May 2021); MEC-CE-655(a) (report not been received); MEC-CE-992(b) (noting that Consumers has received a preview of a draft, but the report is still under development)).

the rule, with a decision on whether to do likely by late July 2021. If EPA revises the rule, those revisions could reinstate the zero liquid discharge requirement included in the original 2015 rule. Such a change would necessitate a new compliance plan and different types of investments at Campbell.

There is additional uncertainty regarding this project because, under the 2020 SEEG rule, Campbell units 1 and 2 would not require any SEEG investments if those units retired by or before 2028. As discussed earlier in my testimony, the upcoming IRP case will include a retirement analysis of Campbell 1 and 2, with four of the five potential retirement dates (2024-26, 2028) coming before the December 31, 2028 deadline under the cessation of coal burning compliance pathway. If Campbell unit 1 and/or 2 are approved for a mid-2020s retirement, that would impact the SEEG compliance strategy and the cost for the project. Consumers has acknowledged that there could be cost savings for "pipe and/or pump sizing," but the current "order of magnitude" cost estimates "are not detailed enough to be able to quantify the potential cost savings."[111]

For all of these reasons, there remains significant uncertainty surrounding the timeline, substance, scope, and ultimate cost of the Company's SEEG compliance strategy. Consequently, it would be premature to award rate recovery of SEEG expenditures in this case. Therefore, the Commission should disallow recovery of these expenditures at this time.[112] The Commission should also ensure the Company submits the conceptual design

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[111] Ex MEC-62, p. 11 (MEC-CE-654(a)).
[112] This recommended disallowance is shown on page 1 of Exhibit MEC-56.
These capital expenditures are reflected in Exhibit A-12 (SAH-3), Schedule B-5.2, page 8, line 10 (2021 SEEG costs) and page 9, line 8 (2022 SEEG costs). These 2021-22 expenditures are also shown in Exhibit A-12 (SAH-3), Schedule B-5.2, page 3, line 106, columns (f) and (j). Separately, Company witness Breining identifies these expenditures in Exhibit A-60 (HAB-2).

for the SEEG project and that it evaluates the potential for Campbell 1 and 2 compliance via the cessation of burning coal pathway.

Q. You have noted that Campbell 1 and 2 will evaluated for retirement in the IRP case. Are the SEEG expenditures avoidable for Campbell units 1 and 2?

A. Yes. In the current rate case, Consumers consolidated all of the SEEG compliance costs under a single project number (5523), which the Company has classified as a plant-wide project. As such, the Company intends to allocate 43% of the SEEG costs to Campbell units 1 and 2, with the remaining 57% allocated to Campbell unit 3.[113] But if Campbell 1 and 2 retire in 2024 or 2025, under the revised SEEG rule those units would not need to incur any SEEG-related costs – they could avoid such costs because they would cease burning coal by 2028.[114] In this scenario, only Campbell 3 would need to comply with the SEEG requirements for bottom ash transport water. Because Campbell 1 and 2 would not require SEEG-related capital expenditures if under a 2024 or 2025 retirement scenario, those costs are, by definition, avoidable.[115]

As noted above, Consumers may realize some cost savings for the SEEG compliance system if Campbell 1 and 2 retire.[116] But even if the mid-20s retirement of units 1 and 2 had no impact on the SEEG project's overall cost, those costs would be avoidable for those two units in that case. Thus, if the Commission disagrees with my recommendation and award cost recovery for SEEG expenditures, 100% of those costs should be allocated to

[113] Ex MEC-62, p. 4 (MEC-CE-034(a)).
[114] 40 C.F.R. 423.19(f).
[115] Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, Par 6 (in this rate case Consumers must identify "avoidable capital expenditures (environmental and non-environmental) . . . for Campbell Units 1 and 2 in 2024 and 2025 retirement scenarios").
[116] Ex MEC-62, p. 11 (MEC-CE-654(a)) (noting that there could be "a savings in pipe and/or pump sizing," but that the Company is unable to quantify such potential cost savings").

Campbell 3 at this time. Because SEEG costs are avoidable as to Campbell 1 and 2, such costs should not be allocated to those units until their retirement date has been determined in the upcoming IRP case.

D. <u>Proposed expenditures at the Campbell plant that lack adequate supporting documentation</u>

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

A. Yes. The Company is requesting rate recovery for a number of capital expenditures that lack adequate support. These unsupported expenditures, which are listed on pages 2 and 3 of Exhibit MEC-56, should not be included in rate base.

Q. Please summarize the inadequacies of these capital projects, and your recommendations.

A. In reviewing Consumers' capital projects at Campbell for the 2021 bridge year and 2022 test year, I found many of these projects lack adequate supporting documentation. These include projects at Campbell units 1 and 2 (individually and combined), projects at Campbell unit 3, and plant-wide projects. Most commonly, these projects have little to no supporting documents, but some of these projects suffer from either inconsistent cost estimates or other major flaws.

The expenditures I recommend disallowing suffer from several types of inadequacies. First, Consumers is seeking recovery for several unsupported capital expenditures that were disallowed in the 2020 rate case. In the previous case, I recommended disallowing capital projects with 2021 spending that lacked adequate supporting documentation. The

Commission ultimately disallowed those projects.[117] In this case, Consumers is again asking to recover many of these 2021 capital costs while still failing to provide supporting documentation. Second, Consumers is also seeking recovery for several capital expenditures planned for the 2022 test year that similarly lack supporting documents. These expenditures should likewise be disallowed due to their lack of support. Third, Consumers is seeking to recover several expenditures whose supporting documentation was highly flawed or inconsistent.

Q. Please describe how you recommended these disallowances in the 2020 rate case.

A. In last year's case, I recommended disallowing 2021 capital expenditures at Campbell if they had insufficient support. In recommending these disallowances, I limited my focus in two respects. First, I only included projects where the projected spending in 2021 was $100,000 or more, or if it was multi-year project whose total costs substantially exceeded $100,000. Second, I only included projects that the Company acknowledged could be deferred beyond the test year. Thus, I recommended disallowing recovery of capital projects that were above this spending threshold, that the Company acknowledged were deferrable, and that lacked sufficient support.[118]

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[117] See Case No. U-20697, Dec. 17, 2020, Order, pp. 73, 78, 79, 80, 94.
[118] See Case No. U-20697, Ex MEC-83 (recommended disallowances).

Q. Did the Commission disallow capital costs at the Campbell units that lacked adequate support?

A. Yes. The ALJ agreed with my recommended disallowances of Campbell capital projects, and the Commission adopted the ALJ's recommendations. The Commission thus disallowed many capital projects at Campbell that were unsupported.[119]

Q. Is the Company still seeking recovery for 2021 spending that was previously disallowed for lacking sufficient documentation?

A. Yes. Of the capital expenditures for 2021 that were previously disallowed, Consumers has again requested recovery for 17 of them. Despite these projects being disallowed last year due to a lack of support, the Company made little effort to rectify these deficiencies.

I reviewed Consumers' proposed bridge spending and found that many of these projects still lack adequate supporting documentation. Of the 17 previously disallowed projects that the Company included in the current case, 16 of them continue to lack any supporting documentation.[120] (The one project that has additional documentation, Project 5707 – "JHC3 Reheater Sootblower," I recommend disallowing for reasons discussed later in my testimony.) Because Consumers did not address the deficiencies that resulted in these 17 projects being disallowed, and because these projects remain unsupported, the Commission should continue to disallow these 2021 expenditures. These recommended disallowances are listed in Exhibit MEC-56.[121]

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[119] Case No. U-20697, Dec. 17, 2020, Order, pp. 73, 78, 79, 80, 94.

[120] The previously disallowed bridge year projects that still lack supporting documentation are projects 5543, 9650, 9653, 9655, 3089, 5594, 5663, 9651, 9654, 9656, 5691, 5693, 9671, 9690, 9692, and 5480. See Ex MEC-56.

[121] The unsupported 2021 capital expenditures that I recommend the Commission continue to disallow are reflected in the Company's exhibits:

Q. Did you identify any 2022 capital spending with insufficient supporting documentation?

A. Yes. Similar to the approach I took last year, I reviewed the Company's 2022 capital expenditures, focusing on projects with more than $100,000 of planned 2022 spending, which the Company identified as deferrable.[122] As in last year's case, I found many test year expenditures that have no supporting documentation. Although some capital projects at Campbell have supporting documents, there are many projects that do not have an IRR, PVR, project charter, scope document, or other supporting document.[123] For some projects, Consumers offered a short explanation in a discovery attachment[124] or in testimony. But these explanations are cursory and are insufficient to support the planned expenditures. Several examples include:

- Project 9671: $750,000 in 2022 for Fuel Handling/Infrastructure Replacements. This project – whose total cost through 2025 is $4.75 million –has no IRR,

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-- project 5693 (JHC3 Mill Complete Overhauls) is identified in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 8, line 8;
-- project 5707 (JHC3 Reheater Sootblower) is identified in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 8, line 6;
-- non-environmental capital expenditures under $1 million are reflected in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 2, lines 1 and 8, column (f) (projects 5543, 9650, 9653, 3089, 5594, 5663, 9651, 9654, 5691, 5693, 9671, 9690, 10257, 5480, 9526, 10730);
-- The three environmental capital expenditures under $1 million are reflected in either line 85 or line 113 of Exhibit A-12 (SAH-3), Schedule B-5.2, p. 3, column (f) (projects 9655, 9656, and 9692).
I cannot identify the exact line number for these environmental projects because the information provided in discovery has somewhat different categories than those listed on page 3 of Schedule B-5.2. Most likely, these three projects are the "other environmental" category (line 113), but I cannot say for certain.

[122] See Ex MEC-58 (identifying which 2022 capital costs the Company has identified as deferrable); U20963-MEC-CE-648-ATT_1.

[123] See Ex MEC-57, p. 10 (In MEC-CE-983, Consumers confirmed that various 2022 capital expenditures do not have supporting documentation).

[124] See Ex MEC-58 ("problem" statements provided in U20963-MEC-CE-013_ATT_44).

project charter, or scope document; this expenditure is supported by only a few lines of limited testimony and two sentences in a discovery attachment.[125]

- Projects 9650 and 9651: each project has $200,000 of spending in 2022 for Major Motor and Pump Overhauls at Campbell units 1 and 2. For both of these items, the Company acknowledges that the "specific projects" for test year spending "will be identified at a future date."[126]

- Project 5691: $900,000 in 2022 to replace O2 monitors at Campbell unit 3. Despite the cost of this project, and despite a similar expenditure for 2021 being disallowed in last year's rate case,[127] the Company has not prepared a scope document, project charter, or any other document to support these expenditures.[128]

Exhibit MEC-56 shows those 2022 expenditures that should be disallowed in this case due to lack of supporting documentation or inconsistencies. As the exhibit shows, for several of these projects, I have recommended that both 2021 and 2022 expenditures be disallowed.[129]

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[125] *Id.*; Hugo Direct, pp. 60, 64.
[126] Hugo Direct, p. 56.
[127] Case No. U-20697, Dec. 17, 2020, Order, pp. 77-78.
[128] This project is only supported by limited testimony, Hugo Direct, pp. 47-48, 62, and two sentences in a discovery attachment. U20963-MEC-CE-013-ATT_44, row 54 (reproduced in Ex MEC-58).
[129] The inadequately supported 2022 capital expenditures that I recommend disallowing are reflected in the Company's exhibits:
-- The 2022 spending for project 5693 (JHC3 Mill Complete Overhauls) is identified in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 9, line 6;
-- project 11249 (JHC3 Boiler Roof Replacement) is identified in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 9, line 5;

Q. Is the Company seeking recovery for projects where it plans on conduct a future economic assessment?

A. Yes. There are four capital projects that the Company identified as "economic" and stated that an economic assessment would be performed later in 2021 or 2022: The Company has stated that it is planning an economic assessment for the following capital projects:

- 5589 – "JHC1 SH Outlet Pendant Tube Panel Replacements"
- 5692 – "JHC3 SH Terminal Tube Replacement"
- 5749 – "JHC3 Replace Boiler Sidewall Panels"
- 5750 – "JHC3 Replace Boiler Front and Rear Wall Panels"[130]

Because these projects will require – but do not yet have – an economic assessment, any bridge or test year spending associated with them should generally not be included in rate base at this time. (Project 5589 should also be disallowed because, as discussed above, this project is avoidable under the Campbell 1 and/or 2 retirement scenarios.) However, the Company has also clarified that the 2021 expenditures for projects 5749 and 5750 ($10,000 each) is limited to performing economic assessments; the Company states that it would

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-- non-environmental capital expenditures under $1 million are reflected in Exhibit A-12 (SAH-3), Schedule B-5.2, p. 2, lines 1 and 8, column (j) (projects 9650, 9653, 9651, 9654, 5691, 5693, 5708, 5749, 5750, 9671, 9689, 9690, 11249, 9526, 10730);

-- The four environmental capital expenditures under $1 million are reflected in either line 85 or line 113 of Exhibit A-12 (SAH-3), Schedule B-5.2, p. 3, column (j) (projects 9655, 9656, 9692, and 9397).

I cannot identify the exact line number for the four environmental projects because the information provided in discovery uses somewhat different categories than those listed on page 3 of Schedule B-5.2. Most likely, all four projects are under the "other environmental" category (line 113), but I cannot say for certain.

[130] Ex MEC-57, pp. 2-3 (MEC-CE-13(c)(ii)(a)). Note that project 5753 was canceled after an economic assessment (see MEC-CE-643(c)).

cancel the projects if not economically beneficial.[131] (Note that the Company projects more than $2 million in spending on each of these projects after 2022.)

Given the low cost ($10,000) for each analysis that has been identified, I am not recommending a disallowance for the 2021 spending on the assessments themselves but including the 2022 costs in rates would be premature. The economic assessments, if done properly in 2021, and with up-to-date information, would indicate whether the projects should be pursued or not in 2022. Because there is the potential that these projects will not be shown to provide economic benefits, the 2022 spending should be disallowed.[132]

Q. Did you determine that some projects had 2021 and 2022 spending that was significantly inconsistent from what was found in the project documentation?

A. Yes. If the cost estimates projects change substantially, the Company should document those changes as soon as possible. I found three projects which had substantial inconsistencies between the estimated cost included in the project charter, and the amount that the Company is seeking to recover in this case:

- 10257 – "JHC3 FD fan vibration monitor equipment replacement." The project charters had a stated budget of $116,922, with costs incurred in 2019. In this case, however, the Company has $251,400 of spending, with costs incurred in 2021.[133]

[131] Ex MEC-57, p. 2, 7 (MEC-CE-013(c); MEC-CE-644(b)).
[132] For similar reasons, I have not recommended a disallowance of the 2022 expenditures for project 5692; those costs are solely for an economic assessment.
[133] U20963-MEC-CE-013_ATT_45; U20963-MEC-CE-013_ATT_44.

- 11249 – "JHC3 Boiler Roof Replacement." According to the scope document, the estimated cost of this project is at $1,680,000. But the Company is seeking approval for $2,656,000 in 2021-22.

- 5708 – "JHC3 Sootblowing Air Compressor Controls." According to the project charter, which was completed in early 2019, the budget for this project is $50,000.

When asked in discovery to explain these discrepancies and provide any updated cost estimates, the Company did not provide any project-specific information. Instead, the Company provided a blanket statement about documentation for projects and made no attempt to explain these specific discrepancies.[134] Given the substantial discrepancies within these projects' documentation, I am recommending that these costs be disallowed.

Q. Did you find any projects with flawed economic assessments?

A. Yes. Where Consumers provided an economic assessment (such as an IRR) for a project, I reviewed that underlying analysis. My review of the economic assessments included a determination if the assumptions and methodology were well documented and up-to-date. Ultimately, I found three capital projects where the economics assessments were significantly flawed: 5707 (JHC3 Reheater Sootblower), 9526 (JHC3 Replace ABB Damper Drives), and 10730 (JHC Ash Silo Secondary Electrical Source). For each of these projects, the Company relied on an IRR analysis [[[redacted]]][135] The usage of [[[redacted]]] is not acceptable to

[134] Ex MEC-57, p. 18 (MEC-CE-987(e), (f), (g)).
[135] Ex MEC-66C (MEC-CE-996-CONF, 997-CONF, and 998-CONF).

justify a capital investment decision. The 2021 and 2022 spending on these projects should be disallowed and the Company should re-assess the net benefits of these investments using [[[redacted]]] before seeking rate recovery.

The situation with project 5707 is particularly curious. In the 2020 rate case, I recommended disallowing this project due to lack of supporting documents. I noted that this was an "economic" project, and the Company admitted that it had not yet performed an economic assessment for it.[136] In recommending this project be disallowed – a recommendation the Commission adopted – the ALJ "noted Consumers' admission that an economic analysis needed to be performed."[137] Yet in this case, when the Company provided an economic analysis for project 5707, it produced an IRR [[[redacted]]] Regardless, it remains the case that this economic project has still not been properly supported, and thus the Commission should continue disallowing these costs.

Q. Please summarize your recommendations regarding costs which lack adequate supporting documentation.

A. Above I have outlined several variations of inadequate support for 2021 and 2022 spending. For the reasons explained, I recommend disallowing recovery of these projects. Exhibit MEC-56 shows those projects that should be disallowed in this case due to

[136] Ex MEC-67 (U20697-MEC-CE-1014(a)) ("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.").
[137] Case No. U-20697, Dec. 17, 2020, Order, p. 78 (citing PFD, p. 123).

inadequate documentation. In total, these projects represent $8.2 million in capital spending in 2021 and $9.3 million in 2022.

Q. You did not recommend disallowing any major maintenance expenses. Are any of those projects of particular concern?

A. Yes. Project 9531 – "JHC3 Turbine/Generator Inspection" – is concerning because it lacks any supporting documentation, and yet the Company is planning to spend roughly $8.5 million on this project between 2022 and 2024.[138] While only a small part of the project's costs are in the test year—$93,310 in 2022—I am concerned that if these test year costs are unequivocally allowed in rates, the Company may use that decision to justify inclusion of the remaining $8.4 million in 2023 and 2024. If the 2022 expenses for this project are approved, I suggest that the Commission caution Consumers that future rate case filings should include documentation for this project, and if the Company does not provide such documentation, any post-2022 costs may be disallowed.

Q. Please summarize your recommendations for 2021 bridge year disallowance.

A. I recommend the following 2021 capital expenditures at Campbell be disallowed (shown in Exhibit MEC-56):

1. Capital expenditures in 2021 that were previously identified as avoidable and disallowed by the Commission in the previous rate case. These include $3.7 million in 2021 capital spending.

[138] MEC-CE-013_ATT_44, "MM (iii) tab," line 67.

2. Capital expenditures in 2021 for Steam Electric Effluent Guidelines (SEEG) costs that are subject to significant uncertainty. These include $1.9 million in 2021 capital spending.
3. Expenditures in 2021 for projects that lack adequate support, including those that were disallowed in the previous case for this reason. These include $8.2 million in 2021 capital spending.

Q. Please summarize your recommendations for 2022 test year disallowance.

A. I recommend the following 2022 capital expenditures at Campbell be disallowed (shown in Exhibit MEC-56):

1. Capital expenditures in 2022 that Consumers has identified as avoidable. These include $952,000 in 2022 capital spending.
2. Capital expenditures in 2022 for SEEG costs that are subject to significant uncertainty. These include $15.4 million in 2022 capital spending.
3. Expenditures in 2022 for projects at Campbell that lack adequate support. These include $9.3 million in 2022 capital spending.

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. The Company estimates $4 million in incremental costs in 2021 at Campbell 3 if the other two units retired in 2024.[139]

[139] Ex A-94 (SAH-4), p. 2.

The Company further projected incremental costs that would be incurred in subsequent years with a 2024 or 2025 retirement of Campbell 1 and 2.[140]

Q. Are these types of costs unavoidable?

A. Yes. The Company only identified "incremental" costs associated with 2024 or 2025 retirement. But such costs are not "incremental" with respect to retirement year 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. [141] 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's cost projection is identical to the one provided in the 2020 rate case.[142] In last year's case, the Company was unable to provide any supporting documentation for its cost estimates, acknowledging that the cost estimates were "an educated order of magnitude estimate" that assumed a "worst case scenario."[143] In the current case, the Company provided documentation for some of the costs.[144] Curiously, however, the Company did not make any change to its projection of total incremental spending. Additionally, the Company did not provide any support for its assumption that "loadings and oversight costs" would total $29.2 million.[145]

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[140] WP-SAH-51.
[141] Ex MEC-48, pp. 1-2 (MEC-CE-014(c, d)).
[142] Compare Case No. U-20697, Hugo workpaper WP-SAH-23 with Case No. U-20963, Hugo workpaper WP-SAH-51.
[143] Ex MEC-48, p. 3 (U20697-MEC-CE-546(a)).
[144] U20963-MEC-CE-014_Att_1_Confidential.
[145] Ex MEC-48, p. 1 (MEC-CE-014(a)(i).

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 retirement 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, in the IRP case the Commission will review Consumers' evaluation of different potential retirement dates for Campbell 1 and 2 (which Consumers will submit with its June 2021 IRP). The retirement evaluation should include a more detailed incremental cost estimate that: 1) backs up the assumed incremental costs with documentation; 2) includes costs under each retirement year scenario; and 3) escalates costs with the spending year. These features are necessary in order to prevent the retirement analysis from being biased towards continued operation of the Campbell units.

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.[146] In the previous IRP case, No. U-20165, Company witness Norman Kapala provided a high-level overview of this

[146] Ex MEC-68, p. 4 (MEC-CE-659(a)(i)).

plan.[147] Thus far, the Company [[[redacted].]] For example, whereas [[[redacted]]].[148] In this case, Consumers has stated to the future-use study remains "in progress"[149] – [[[redacted]]] In last year's rate case, Consumers stated that it would update the community transition plan in late 2020,[150] but in the current case, the Company has acknowledged that this plan has still not been updated.[151] More details about the timing and process to develop and implement the transition plan, including the future-use study, should be provided.

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

A. That is not clear. There is a "preliminary" estimate that shows $375,000 towards economic development, and $355,000 in public relations activities and sponsorships.[152] The Company has previously discussed significant spending for the retention and separation

[147] Case No. U-20165, Direct Testimony of Norman J. Kapala, 8 TR 1147-48. It is unclear [[[redacted]]]
[148] Ex MEC-69C, p. 13 (U20697-MEC-CE-053-Hugo_CONF_ATT_1).
[149] Ex MEC-68, p. 2 (MEC-CE-028(h)).
[150] Ex MEC-68, p. 6 (U20697-MEC-CE-549(a)).
[151] Ex MEC-68, p. 2 (U20963-MEC-CE-028(b)).
[152] Ex MEC-68, p. 3 (U20963-MEC-CE-028-Hugo_ATT_1).

program for current Karn employees,[153] but has not provided details on spending to address other retirement-related impacts.

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.[154] The Company has described the transition plan as "a business confidential document for Company use only."[155] While I understand if there is specific competitively sensitive information that the Company would claim confidentiality, Consumers should still issue a public version of the plan. The existence of confidential data does not mean that the Company abdicates responsibility from informing the affected community.

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

A. It is not clear. While [[redacted]], the Company stated in discovery in the 2020 rate case that it "is not consulting with community groups or community leaders in updating the plan" and did "not plan to conduct a public forum to receive input."[156] Although the Company more recently indicated an intention to begin virtual quarterly updates in 2021,[157] it is unclear who is invited to and

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[153] See, e.g., Hugo Direct, pp. 134-39 (discussing Karn retention and separation plan).
[154] See Ex MEC-69C (U20697-MEC-CE-053-Hugo_CONF_ATT_1). In MEC-CE-028, the Company provided permission to use the community transition plan in this case, which was confidentially produced in last year's rate case (No. U-20697).
[155] Ex MEC-68, p. 7 (U20697-MEC-CE-1029(a), (b) (admitted as Ex MEC-99 in Case No. U-20697).
[156] *Id.*
[157] Ex MEC-68, p. 2 (MEC-CE-028(f)).

participates these updates, and whether or how the Company intends to solicit input from the local community.

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 its 2020 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.[158]

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."[159]

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 as soon as possible. The transitional plan itself should also be made public.

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[158] Case No. U-20651, May 8, 2020, Order, p. 189.
[159] *Id.*

VI. <u>CONCLUSION AND RECOMMENDATIONS</u>

Q. What do you recommend to the Commission?

A. For the reasons explained above I recommend the following:

1. The Commission should continue to disallow the 2021 capital costs that were found avoidable in Case No. U-20697, and which the Company is again seeking to recover.
2. The Commission should disallow 2022 capital costs could be avoided if Campbell 1 and 2 retire in 2024 or 2025.
3. The Commission should disallow 2021 and 2022 capital expenditures associated with SEEG compliance.
4. The Commission should disallow bridge and test year capital costs that Consumers has not adequately supported.
5. The Commission should direct Consumers to provide additional details on its updated Karn community transition plan as soon as possible. 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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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.

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Tufts University, Medford, MA

Master of Arts in Economics, 2007

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Applied Economics Clinic
Economic and Policy Analysis of Energy, Environment and Equity

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Resume dated May 2021

Fixed O&M Costs at Campbell units 1 and 2

	Actual						CE 2021 Projection				
Fixed O&M ($mil)	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Campbell 1	$10.74	$10.76	$9.76	$9.59	$8.79	$13.08	$11.55	$12.62	$12.12	$14.28	$12.74
Campbell 2	$11.48	$11.93	$10.63	$13.65	$10.39	$9.96	$16.57	$12.10	$12.12	$12.14	$13.97

Source *MEC-CE-010_Hugo_Att_1* *MEC-CE-011_Hugo_Att_1*

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

Question:

7. Refer to the WP-SAH-51 workpaper and Exhibit A-94 (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 of WP-SAH-51

      ii. the incremental costs for 2021-25 listed on lines 17-19 of WP-SAH-51

   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 $104.3 million.

   c. Please confirm that the incremental costs shown on lines 8 and 17 of WP-SAH-51 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-51 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:

Objection by Counsel: The Company objects to this request to the extent that it seeks confidential business information. The disclosure of such information could cause harm to the Company and its customers. The requested confidential business information will only be provided subsequent to the execution of a suitable confidentiality and nondisclosure agreement. The Company also objects to the extent that this request is overly broad, unduly burdensome, and not proportional to the needs of the case. Subject to this objection, and without waiving it, the Company provides the following response:

a.

i. The cost estimated on line 8 of WP-SAH-51 is a conceptual estimate based on a study completed by Sargent & Lundy with the known scope to date to decommission JH Campbell 1&2 and continue to operate JH Campbell 3. The study was completed in the second quarter of 2020. The study's estimate does not include loadings and oversight costs. These were estimated at $29.2M; $18.8M loadings and $10.4M oversight. The study is included as U20963-MEC-CE-014_Att_1_Confidential. Lines 9 and 10 are based on the actual costs incurred during the closure of the Weadock, Whiting and Cobb sites.

ii. The cost estimated on line 8 of WP-SAH-51 is a conceptual estimate based on a study completed by Sargent & Lundy with the known scope to date to decommission JH Campbell 1&2 and continue to operate JH Campbell 3. The study was completed in the second quarter of 2020. The study's estimate does not include loadings and oversight costs. These were estimated at $29.2M; $18.8M loadings and $10.4M oversight. The study is included as U20963-MEC-CE-014_Att_1_Confidential. Lines 18 and 19 are based on the actual costs incurred during the closure of the Weadock, Whiting and Cobb sites.

b. Included in subpart (a).

c. Confirmed

d. Confirmed

Scott A. Hugo
April 13, 2021

Director – Generation Asset Strategy

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

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
April 6, 2020

Director – Generation Asset Strategy

Question:

9. Refer to page 9, lines 10-11 and page 13, lines 1-7 of the Direct Testimony of Scott A. Hugo, and to column (f) of Exhibit A-93 (SAH-2).
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. Since February 27, 2020, has the Company made any changes to the methodology used to calculate NEVs for its generating units? If so, please describe in detail such changes, and explain how those changes impact the calculated NEVs.
c. For each of the Company's coal units, please identify:
i. The actual NEV for 2020 (or projected NEV for any portion of 2020 where actual figures are not yet available).
(a) If the Company does not yet know the actual NEV for all of 2020, 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 2021 through 2025 (or latest year available).
(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 projected NEVs for each of the years 2021 through 2025.

Response:

Objection by Counsel: The Company objects to this request to the extent that it seeks confidential business information. The disclosure of such information could cause harm to the Company and its customers. The requested confidential business information will only be provided subsequent to the execution of a suitable confidentiality and nondisclosure agreement. Subject to this objection, and without waiving it, the Company provides the following response:

a. Please see Attachment U20693-MEC-CE-016_ATT_1 Confidential for requested file which supports Exhibit A-93 (SAH-2) column (f).
b. No. The Company has not made any changes to the methodology used to calculate historical NEVs for its generating units.
c.
   i. Please see Attachment U20693-MEC-CE-016_ATT_2 Confidential for the Company's 2020 NEV values for its coal units.

   ii. Please see Attachment U20693-MEC-CE-016_ATT_3 Confidential for the Company's 2021-22 NEV values for its coal units. The data was developed using the modeling performed for the electric rate case and analysis beyond 2022 was not performed.

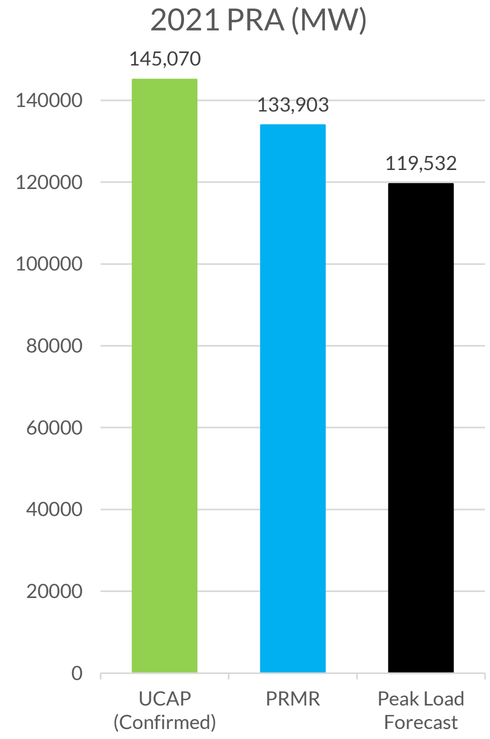
Scott A. Hugo
April 12, 2021

2021/2022 Planning Resource Auction (PRA) Results

April 15, 2021

MISO region has adequate reserves to meet its 134 GW Planning Reserve Requirement

- Zones 1-7 cleared at **$5.00**/MW-day, while Zones 8-10 cleared at **$0.01**/MW-day. Compared to last year, lower prices in Zones 7-10 are a result of a combination of lower peak demand or additional supply
- PRA enhancements implemented in the past year did not directly impact clearing prices
- Cleared capacity showed continued trend to non-conventional resources, which along with resource performance in tight conditions, is the basis for Reliability Imperative efforts
- Regional generation supply was consistent with the 2020 OMS-MISO Survey



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

Primary changes since 2020 Auction

Conventional Deliverable ICAP (ER20-1942)

FERC accepted a Tariff filing on October 27, 2020 to increase the deliverability requirements for Capacity Resources and related conversion of Capacity to Zonal Resource Credits (“ZRCs”) in MISO’s Planning Resource Auction. This filing addresses the deliverability and conversion rules applicable to conventional resources. In order to obtain full capacity credit, the resource must by fully deliverable.

Intermittent Deliverable ICAP (ER20-2005)

FERC accepted a Tariff filing on November 13, 2020 to increase the deliverability requirements for Capacity Resources and related conversion of Capacity to Zonal Resource Credits (“ZRCs”) in MISO’s Planning Resource Auction. Amount of capacity eligible to be converted into ZRCs depends on the performance and deliverability level of the intermittent resource.

Annual CIL/CEL Study’s Voltage Stability Analysis Methodology (LOLEWG)

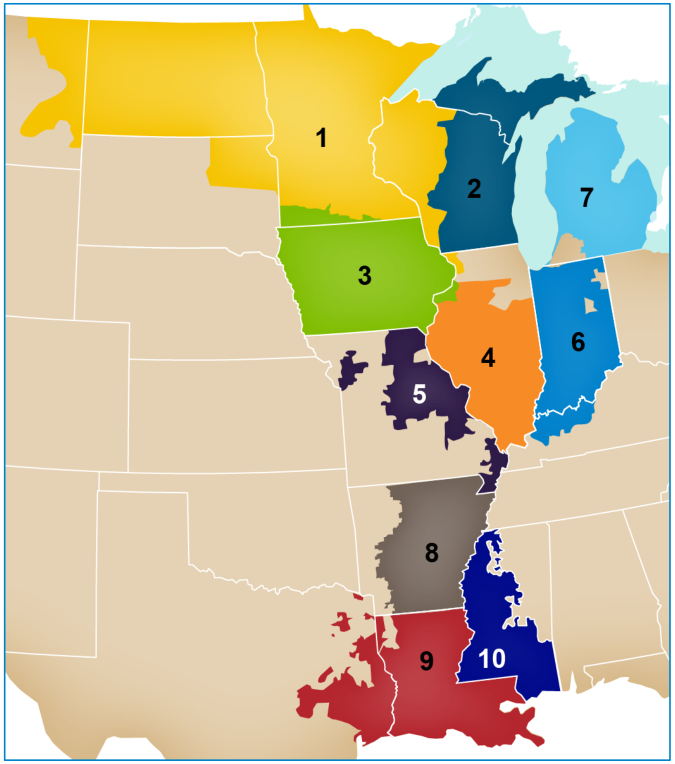
CIL/CEL studies utilize generator to generator transfers, however Zonal imports may be limited by voltage constraints. For additional voltage analyses , the PY 21/22 transfer utilizes a gen-gen transfer methodology, whereas the previous PY utilized a load-load transfer method. Gen to Gen transfer is more reflective of system capability at peak hour.

Ongoing Fleet Change

The auction results reflect the industry’s ongoing shift away from coal-fired generation and increasing reliance on gas-fired resources and renewables, as well as other trends discussed in our MISO Forward report.

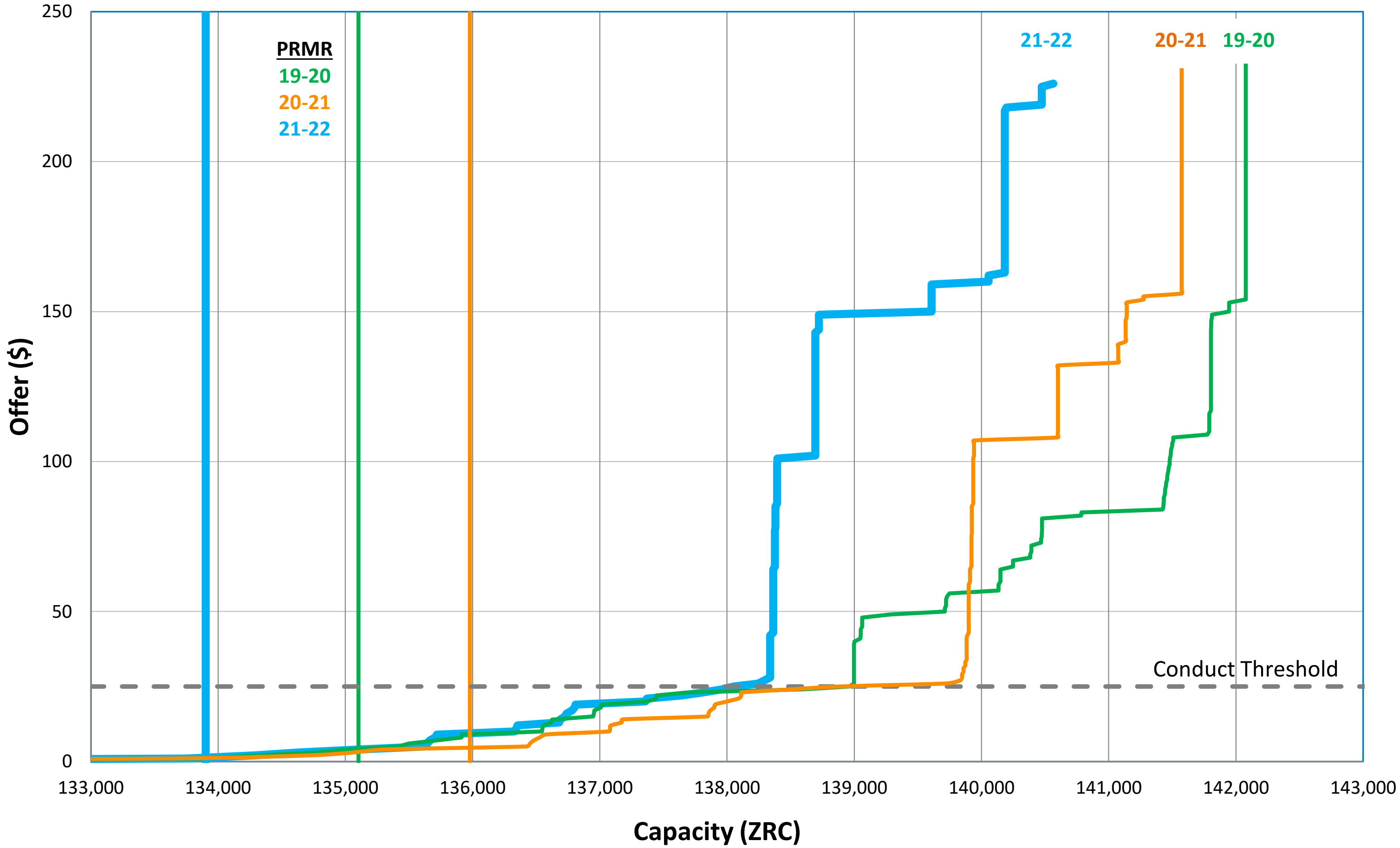
South to North capacity transfer limit reached causing price separation of $4.99

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	$5.00
7	CONS, DECO	$5.00
8	EAI	$0.01
9	CLEC, EES, LAFA, LAGN, LEPA	$0.01
10	EMBA, SME	$0.01
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	$2.78-5.00



ERZ = External Resource Zones

2021-22 Offer Curve

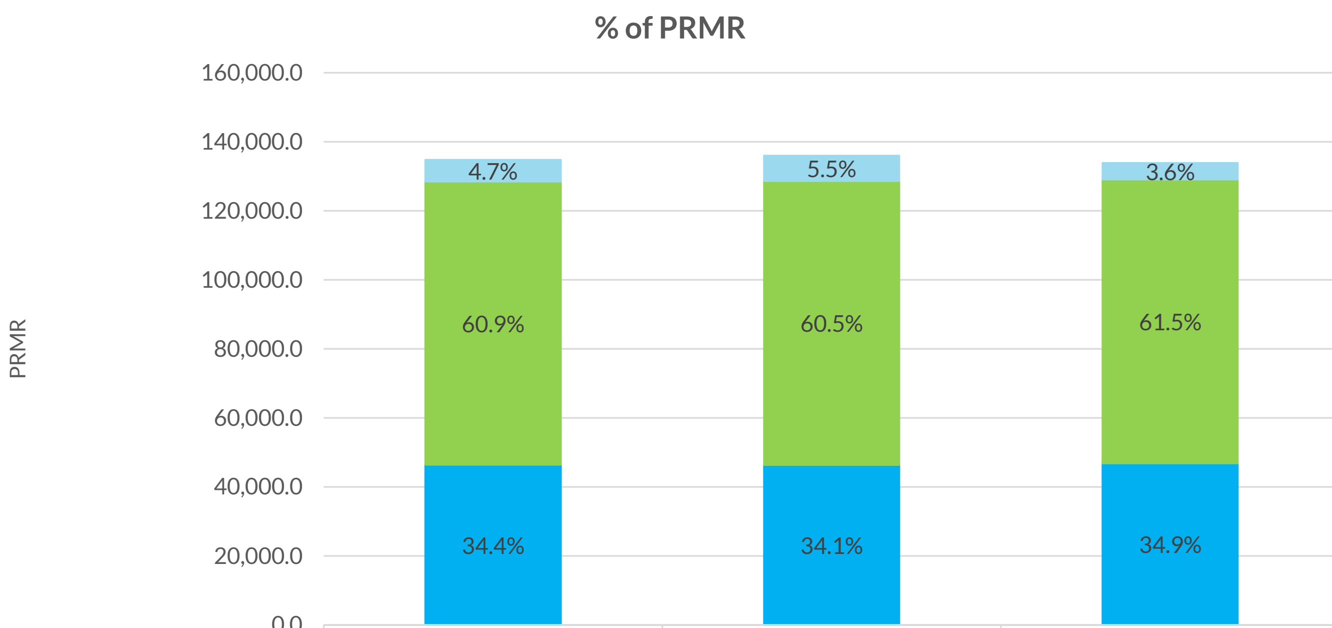


2021/22 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,359.0	13,616.5	10,279.5	9,852.5	8,246.8	18,145.8	21,459.2	7,827.8	21,282.6	4,833.0	N/A	133,902.7
Offer Submitted (Including FRAP)	20,289.3	13,979.9	10,826.7	9,506.1	7,811.4	15,832.2	21,666.3	10,642.5	23,017.4	5,353.8	1,639.4	140,565.0
FRAP	14,408.1	11,657.8	4,159.9	669.0	0.0	1,519.7	12,186.4	513.5	174.7	1,374.2	94.1	46,757.4
Self Scheduled (SS)	3,507.4	2,290.3	6,097.5	6,327.8	7,811.4	12,519.4	9,295.5	9,299.4	20,151.5	3,591.7	1,395.0	82,286.9
Non-SS Offer Cleared	772.0	0.0	454.3	1,335.2	0.0	1,706.8	67.5	116.6	308.1	0.0	97.9	4,858.4
Committed (Offer Cleared + FRAP)	18,687.5	13,948.1	10,711.7	8,332.0	7,811.4	15,745.9	21,549.4	9,929.5	20,634.3	4,965.9	1,587.0	133,902.7
LCR	14,875.1	10,670.0	6,713.7	6,450.4	5,282.8	12,166.3	19,710.1	4,988.4	19,404.2	3,632.8	-	N/A
CIL	5,061	3,599	4,620	NLF*	4,384	7,138	4,888	5,203	4,096	3,283	-	N/A
ZIA	5059	3599	4556	5141	4384	6738	4888	5155	3284	3283	-	N/A
Import	0.0	0.0	0.0	1,520.5	435.4	2,399.9	0.0	0.0	648.3	0.0	-	5,004.1
CEL	2,474.0	3,488.0	NLF*	4,912.0	NLF*	4,595.0	NLF*	NLF*	1,978.0	1,369.0	1,452.2	N/A
Export	328.5	331.6	432.2	0.0	0.0	0.0	90.2	2,101.7	0.0	132.9	1,587.0	5,004.1
ACP ($/MW-Day)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	0.01	0.01	0.01	2.78 to 5.00	N/A

Values displayed in MW UCAP *NLF = No Limit Found: Tier 1 & 2 source capacity is less than the study transfer limit

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



	19-20	20-21	21-22
Cleared Non-Self Scheduled	6,281.9	7,419.1	4,858.4
Self Scheduled	82,046.9	82,240.0	82,286.9
FRAP	46,414.2	46,320.2	46,757.4

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>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>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-
$5.00</td></tr>
</table>

IMM Conduct Threshold	25.43	24.92	23.92	24.86	26.67	24.42	25.97	23.09	22.90	22.86	26.67
Cost of New Entry	254.27	249.15	239.21	248.55	266.68	244.16	259.73	230.93	229.04	228.55	266.68

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

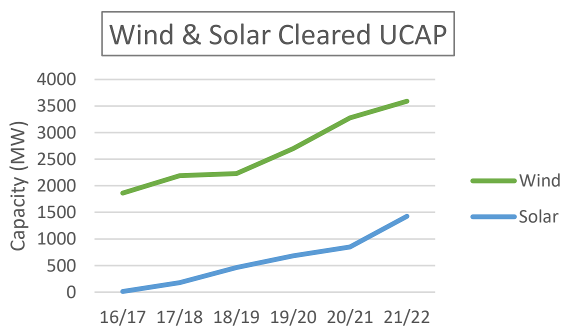
Supply Offered & Cleared

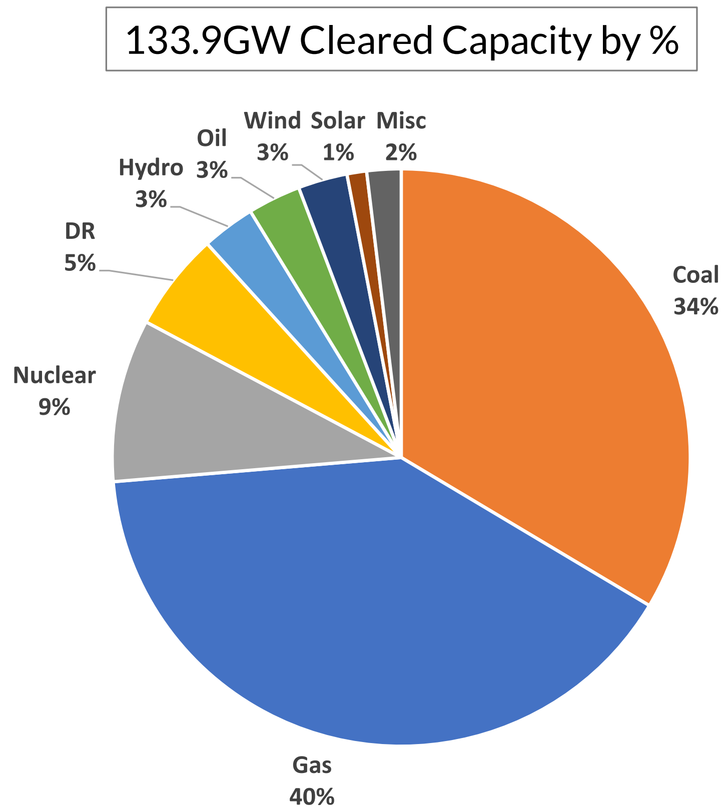
	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**2019-20**	**2020-21**	**2021-22**	**2019-20**	**2020-21**	**2021-22**
Generation	125,290	125,341	125,225	119,779	120,143	118,884
External Resources	4,402	3,832	3,914	3,183	3,736	3,798
Behind the Meter Generation	4,202	3,997	4,131	4,097	3,892	4,068
Demand Resources	7,876	7,754	7,294	7,372	7,557	7,152
Energy Efficiency	312	650	0	312	650	0
Total	**142,082**	**141,574**	**140,564**	**134,743**	**135,979**	**133,903**

Conventional generation provides majority of capacity, while wind and solar continue to grow

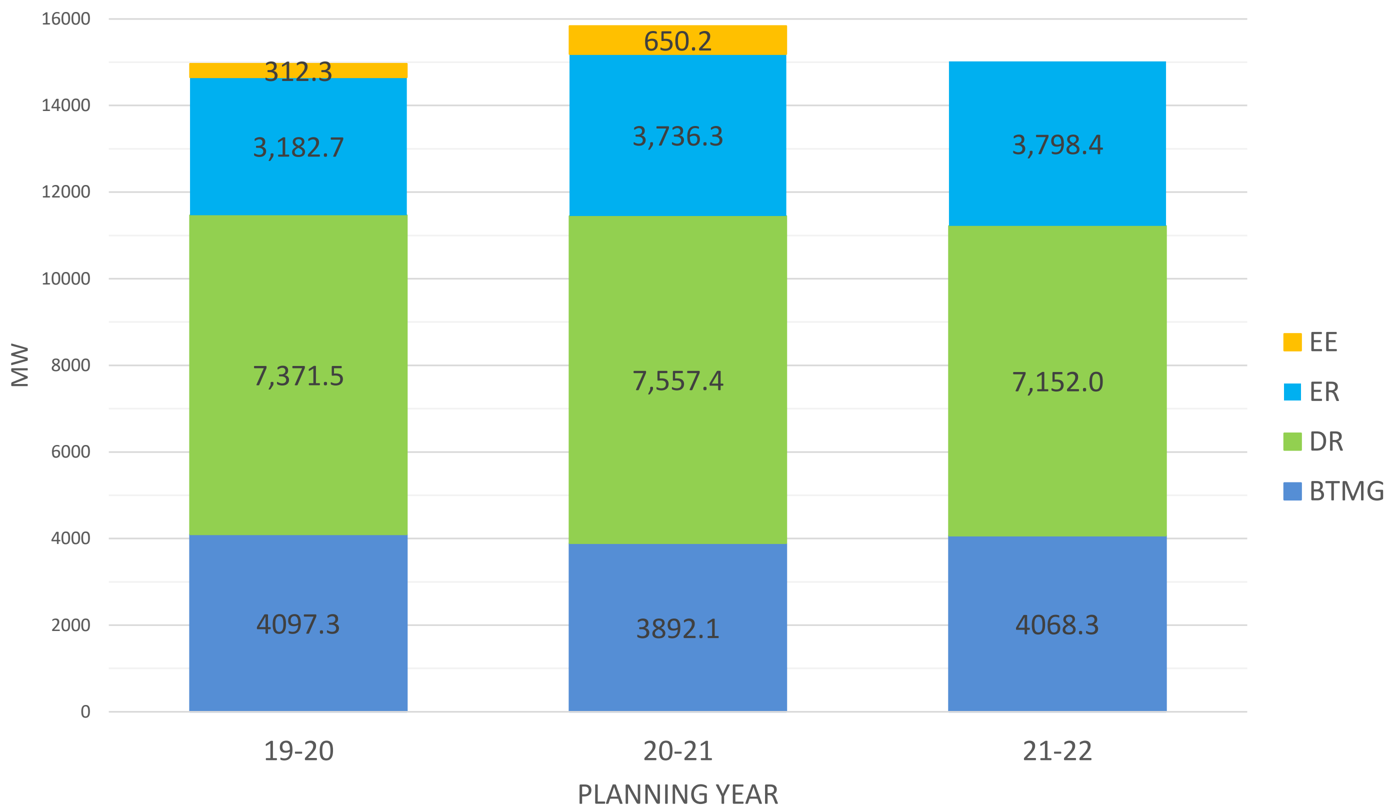
- 1,426 MW of solar cleared this year's auction—an increase of 68% from PY 2020-21 (850 MW).

- Similarly, 3,590 MW of wind cleared this year, an increase of 10% compared to last year (3,275 MW).

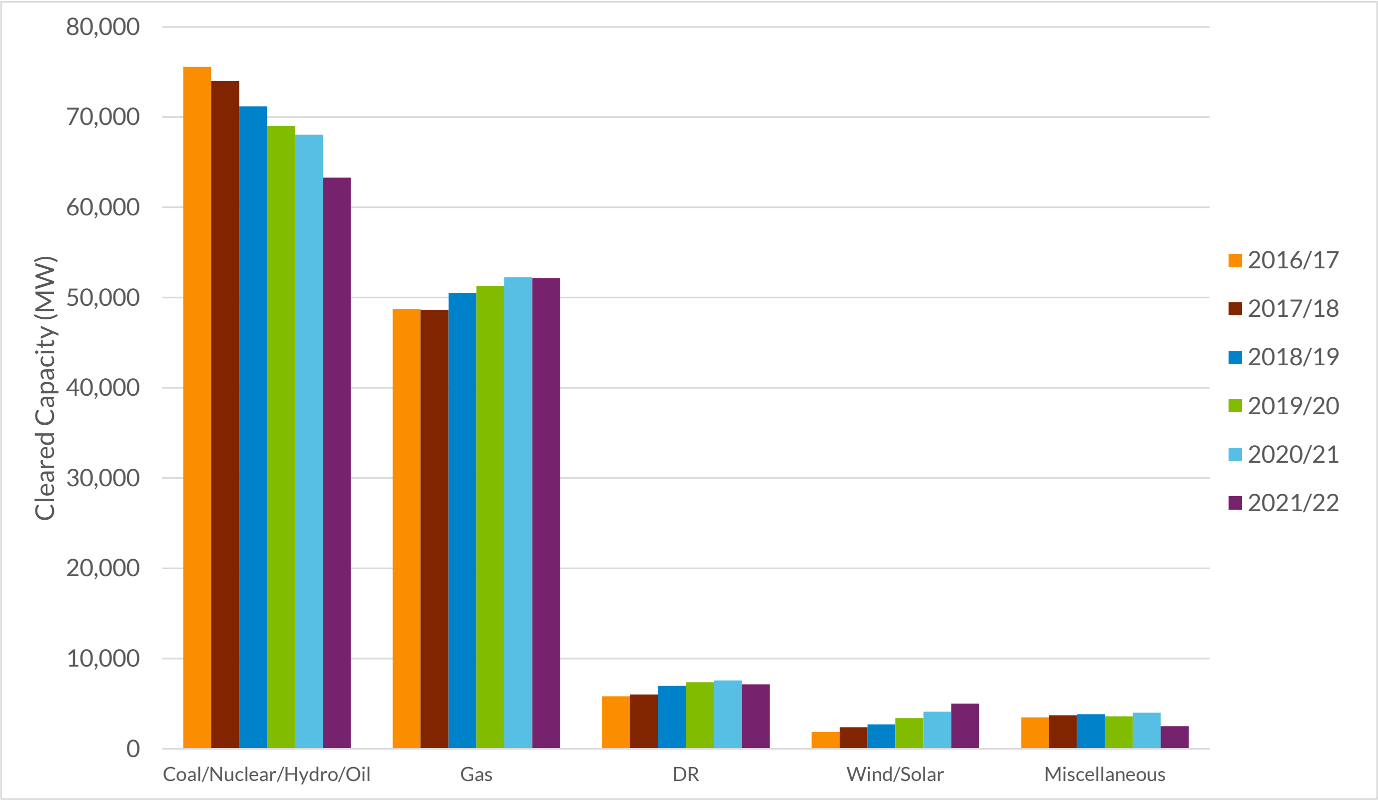




Demand-based resources declined due to lack of qualified Energy Efficiency



Planning resource mix continues the multi-year trend of less solid fuel and increased gas and non-conventional



Next Steps

- **APR 15** – Conference call presentation of PRA results
- **MAY 12** – Zonal Deliverability Benefits and additional PRA analytics at the May RASC
- **MAY 14** – Posting of PRA masked offer data
- **MAY 25** – MISO published cleared LMRs to the MCS
- **MAY 28** – MPs submit ICAP and DR Testing 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

RAdequacy@misoenergy.org

Question:

10. Refer to Table 2, and to page 14, line 8 through page 15, line 1 of the Hugo Direct Testimony.

    a. Please identify the capacity value for each of the Company's coal units for 2019 and 2020. (Please provide the projected capacity value for any portion of 2020 where actual figures are not yet available.)

    b. 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 2021-25, including supporting assumptions for those values.

    c. Is the 75% of CONE capacity value presented in Table 2 based on the Company's estimate of the cost of acquiring replacement capacity?

        i. If so, please provide any documents or other information supporting such estimate.

        ii. If not, please explain the basis for the 75% of the CONE assumption, and provide any supporting documents or other information.

    d. d. Is it the Company's belief that the capacity value of Campbell Units 1 and 2 is equivalent to 75% of CONE?

        i. If so, please provide the complete factual basis for that belief, and produce any documents supporting such belief.

        ii. If not, please identify the Company's current estimate of Campbell 1 and 2's capacity value.

Response:

a. The capacity values for the Company's coal units for the 2020-2021 planning year are included in the column titled Capacity Value Zone 7 (Settlement) in Table 2 on page 15 of my direct testimony. The capacity values for the Company's coal units for the 2019-2020 planning year are provided below in the column titled Capacity Value Zone 7 (Settlement):

RESOURCE	MICHIGAN LOCATION	NET GENERATING CAPABILITY (MW)	MISO CAPACITY CREDITS (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[1]	CAPACITY VALUE ZONE 7 (CONE)[2]
COAL FIRED					
JH Campbell 1	West Olive, MI	260	251	$ 2,226,245	$ 22,296,343
JH Campbell 2	West Olive, MI	333	304	$ 2,696,328	$ 27,004,335
JH Campbell 3	West Olive, MI	785 (owned share)	757	$ 6,714,212	$ 67,244,348
DE Karn 1	Essexville, MI	255	223	$ 1,977,899	$ 19,809,101
DE Karn 2	Essexville, MI	253	226	$ 2,004,507	$ 20,075,591

1 2019-2020 PRA Settlement price of $24.30/MW-day for Zone 7.
2 2019-2020 PRA CONE price of $243.37/MW-day for Zone 7.

b. Please see Attachment U20963-MEC-CE-017_ATT_1.

c. Yes. The Company bases its 75% of CONE capacity value on MISO's published CONE value times 75%. MISO bases this calculation for CONE on the cost of a new CT.

   i. See response to subpart (c) as well as Attachment U20963-MEC-CE-017_ATT_1. The Company also relies on the CONE value provided by MISO.
   ii. Not applicable.

d. To some extent, yes. 75% of CONE is a reasonable estimate of the value of small to medium increments of capacity from these resources. However, the 75% of CONE value assumption may not be applicable when considering large amounts of capacity. For example, a higher value of capacity may be appropriate when considering replacing all of the capacity from one or both of these units. 75% is the appropriate value when considering investments that incrementally increase capacity credit either through minor uprates or through reduced forced outages.

   i. The Company estimates the value of Campbell Units 1 and 2 in future years by using 75% of our estimated CONE (provided in U20963-MEC-CE-017_ATT_1).

   ii. Not applicable.

Scott A. Hugo
April 13, 2021

Director – Generation Asset Strategy

Resource	2021 ZRC	2022 ZRC	2023 ZRC	2024 ZRC	2025 ZRC
Campbell 1	240	242.8	243.6	251.5	250.9
Campbell 2	310.6	318.9	328	329.1	328.5
Campbell 3	755.2	744.4	758.8	754.1	759.5
Karn 1	219.2	215.5			
Karn 2	202.3	200.1			

Estimated capacity value $/day	2021 Capacity Value	2022 Capacity Value	2023 Capacity Value	2024 Capacity Value	2025 Capacity Value
Campbell 1	$46,751	$48,242	$49,369	$51,989	$52,903
Campbell 2	$60,503	$63,362	$66,474	$68,031	$69,265
Campbell 3	$147,109	$147,905	$153,782	$155,886	$160,142
Karn 1	$42,699	$42,818			
Karn 2	$39,407	$39,758			

PRA actuals	
2019 PRA $/MW-day	24.3
2020 PRA $/MW-day	257.53

Forecasted value: 75 % of CONE	
2021 $/MW-day	194.8
2022 $/MW-day	198.7
2023 $/MW-day	202.7
2024 $/MW-day	206.7
2025 $/MW-day	210.9

Year	**PRA Results**	**MISO CONE**	**% of CONE Forecasted**	**Planning Year Annual Value**
2012				62
2013	1.050	99,310		383
2014	16.750	90,100		6,114
2015	3.480	90,530		1,270
2016	72.000	94,830	75%	26,280
2017	1.500	94,900	75%	548
2018	10.000	90,740	75%	3,650
2019	24.300	88,830	75%	8,870
2020	257.530	94,000	75%	93,998
2021		94,800	75%	71,100
2022		96,696	75%	72,522
2023		98,630	75%	73,972
2024		100,603	75%	75,452
2025		102,615	75%	76,961

MISO CONE Assumptions	**Value**		**Unit**
CT size		237	MW
% Debt		55	%
Project Life		20	Yr
Debt Interest Rate		5.2	%
O&M Escalation		2.0	%
GDP Deflator		2.0	%
Fed/State Tax	25 to 33		%
Property Tax & Insu		1.5	% of Capital
WACC	7.96 to 8.19		%
After-Tax ROE		13.4	%
Capital Cost		779.0	$/kW
MISO Zone 7 CONE		94,800	$/MW-Year

75% CONE - Annual Capacity Prices Based on Cost of New CT 2021+
(MISO PRA Actuals Through May 2021)

Year	Planning Year Annual Value	Calendar Year Annual Value	January	February	March	April	May	June	July	August	September	October	November	December
			31	28	31	30	31	30	31	31	30	31	30	31
	($/MW-yr)	($/MW-yr)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)	($/MW-mo)
2010	33.94	31.20	0.25	0.25	0.50	0.35	0.35	5.00	10.00	10.00	3.00	0.25	0.25	1.00
2011	2.25	5.95	2.50	0.94	0.50	0.25	0.25	0.35	0.50	0.28	0.25	0.01	0.02	0.10
2012	61.57	61.62	0.20	0.19	0.10	0.10	0.15	0.40	50.00	10.00	0.15	0.14	0.10	0.09
2013	383.25	225.39	0.19	0.15	0.10	0.10	0.15	31.50	32.55	32.55	31.50	32.55	31.50	32.55
2014	6113.75	3743.05	32.55	29.40	32.55	31.50	32.55	502.50	519.25	519.25	502.50	519.25	502.50	519.25
2015	1270.20	3273.97	519.25	469.00	519.25	502.50	519.25	104.40	107.88	107.88	104.40	107.88	104.40	107.88
2016	26280.00	15933.48	107.88	97.44	107.88	104.40	107.88	2160.00	2232.00	2232.00	2160.00	2232.00	2160.00	2232.00
2017	547.50	11193.00	2232.00	2016.00	2232.00	2160.00	2232.00	45.00	46.50	46.50	45.00	46.50	45.00	46.50
2018	3650.00	2366.50	46.50	42.00	46.50	45.00	46.50	300.00	310.00	310.00	300.00	310.00	300.00	310.00
2019	8869.50	6710.20	310.00	280.00	310.00	300.00	310.00	729.00	753.30	753.30	729.00	753.30	729.00	753.30
2020	93998.45	58780.72	753.30	680.40	753.30	729.00	753.30	7725.90	7983.43	7983.43	7725.90	7983.43	7725.90	7983.43
2021	71100.00	80573.06	7983.43	7210.84	7983.43	7725.90	7983.43	5843.84	6038.63	6038.63	5843.84	6038.63	5843.84	6038.63
2022	72522.00	71933.72	6038.63	5454.25	6038.63	5843.84	6038.63	5960.71	6159.40	6159.40	5960.71	6159.40	5960.71	6159.40
2023	73972.44	73372.39	6159.40	5563.33	6159.40	5960.71	6159.40	6079.93	6282.59	6282.59	6079.93	6282.59	6079.93	6282.59
2024	75451.89	74839.84	6282.59	5674.60	6282.59	6079.93	6282.59	6201.53	6408.24	6408.24	6201.53	6408.24	6201.53	6408.24
2025	76960.93	76336.64	6408.24	5788.09	6408.24	6201.53	6408.24	6325.56	6536.41	6536.41	6325.56	6536.41	6325.56	6536.41

filled cells represent forecasted months

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

Net Energy Values (NEVs) for Campbell units 1 and 2

Net Energy Value ($mil)	actual						CE 2021 projection	
Actual and CE 2021 projection	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Campbell 1	$6.39	$5.96	$4.20	$8.50	$5.69	$1.47	$15.36	$13.60
Campbell 2	$4.34	$6.19	$2.22	$9.13	$4.75	$0.95	$15.86	$17.58
Source	*WP-SAH-46*						*MEC-CE-016-Hugo_CONF_ATT_2**	*MEC-CE-016-Hugo_CONF_ATT_3**

CE 2020 projection	**2020**	**2021**
Campbell 1	$8.58	$7.32
Campbell 2	$11.91	$8.69
Source	*U20697-MEC-CE-032g(ii)*	

* The Company has confirmed that the annual NEV figures in these attachments can be presented on the public record.

Question:

27. For each of the Company's coal units, and for Karn units 3 and 4:

a. Please provide the following information as of December 31 for each of the years 2019 and 2020 by unit:
   i. Gross plant balance
   ii. Accumulated depreciation balance
   iii. Net plant balance
   iv. Net salvage (or negative net salvage)
   v. The identification and quantification of any other category of expense collected through depreciation expense (e.g. asset retirement obligations, remediation accounts, etc.).
   vi. Estimated end-of-useful life date for purposes of setting a depreciation schedule.
   vii. The then-applicable annual depreciation expense attributable to the generating unit.
   viii. Rate of return (specify whether pre-tax or post-tax)
   ix. Equity return
   x. Interest payments
   xi. Taxes
   xii. Any other category of costs that factored into the calculation of the unit's revenue requirement.

b. For each of the years 2019 and 2020, please identify how common area or plantwide costs were allocated (i.e., the percentage assigned to each unit) between each of the following in calculating the revenue requirement. If these allocations changed over time, please specify that in your response.
   i. any common areas for Campbell Units 1 and 2;
   ii. any common areas for the entire Campbell plant (including the cost allocation between Campbell 1&2 and Campbell 3);
   iii. any common areas for Karn Units 1 and 2;
   iv. any common areas for the entire Karn plant (including the cost allocation between Karn 1&2 and Karn 3&4).

Note: In providing the requested information, please provide the depreciation balances, depreciation expenses, etc., that are specifically attributable to the Campbell and Karn units. (In other words, please provide information – including but not limited to depreciation balances – that exclude the unrecovered decommissioning costs attributable to the Classic 7.)

Note: If the Company does not have unit-level information for a particular cost category, please provide the most disaggregated data available

Note: Please provide the requested cost information in machine-readable electronic format, with formulas intact, along with supporting workpapers.

Response:

> **Objection of Counsel: Consumers Energy Company objects to this discovery request because it seeks information that is irrelevant, overly broad, and not proportional to the needs of this case. The Company also objects to this discovery request to the extent it calls for the creation of documents, data, and analyses which currently do not exist. Subject to that objection, and without waiving it, the Company provides the following response:**

a.

i. Please see attachment U20963-MEC-CE-662-Coker_ATT_1.

ii. The 2019 and 2020 accumulated depreciation balances are provided in the attached excel file (U20963-MEC-CE-662-Coker_ATT_1). These balances include the balances of unrecovered decommissioning costs for the previously retired steam plants (Classic 7). In the Company's last depreciation case (U-17653), it was ordered that these unrecovered costs would be collected through the depreciation expense on the remaining sites and the depreciation rates in U-17653 reflect this assumption. Since a portion of the depreciation expense is for the recovery of the Classic 7 decommissioning costs and is not calculated separately, the unrecovered balance of these decommissioning costs is not available. Since the decommissioning costs have been accounted for separately, the attached file calculates the accumulated depreciation for the Campbell and Karn units excluding those costs.

iii. Please see attachment U20963-MEC-CE-662-Coker_ATT_1.

iv. The negative net salvage is provided on page 1 of attachment U20963-MEC-CE-662-Coker_ATT_1. The amounts in the file reflect the amount of salvage received less the cost of removal spent in each year. The amounts shown in the attached file only reflect the negative net salvage attributable to the requested units. However, the net salvage attributable to the previously retired steam plants are allocated across the remaining sites.

v. Depreciation expense, which is collected from customers includes the recovery of the capital asset costs as well as the future cost to retire the assets less any salvage value (negative net salvage). While some of the cost to retire the assets make up the asset retirement obligations (AROs), the accounting for AROs is not part of the regulatory/rate making process. However, the costs to retire the assets which make up the AROs are part of the amounts recovered through depreciation expense. While these costs are incorporated into the depreciation studies used to set the depreciation rates in a depreciation filing, they are not tracked separately as the company books depreciation expense, thus it is not identifiable.

vi. The estimated end-of-useful life dates used in the Company's last depreciation case (U-17653) are 2030 for Campbell 1 &2 and Karn 1-4 and 2040 for Campbell 3. The depreciation rates established in U-17653 went into effect on December 1, 2015 and are still in effect.

vii. The 2019 and 2020 depreciation expense is provided on page 2 of attachment U20963-MEC-CE-662-Coker_ATT_1. As noted above in subpart a.ii, in the Company's last depreciation case (U-17653), it was ordered that the unrecovered decommissioning costs of the Classic 7 would be collected through the depreciation expense on the remaining sites and the depreciation rates in U-17653 reflect this assumption. Since the depreciation expense is calculated using those rates, a portion of the depreciation expense is attributable to the Classic 7 decommissioning. However, the depreciation rates were not calculated in components that would identify the Classic 7 separately.

viii. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2 for the post-tax return.

ix. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

x. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

xi. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

xii. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2 for property taxes and O&M by generation site.

b.

i. The Company does not separate Campbell Units 1 and 2.

ii. The common area assets are primarily allocated 43% to Campbell 1 & 2 and 57% to Campbell 3. However, certain projects may be allocated differently.

iii. The Company does not separate Karn Units 1 and 2.

iv. Because Karn 1 & 2 burn coal and Karn 3 & 4 are fueled by oil, the Karn facility has minimal common areas. Common area assets have not traditionally been split between units, rather they have been assigned to either Karn 1 & 2 or Karn 3 & 4 based on their physical location.

Jason R. Coker

Jason R. Coker
May 14, 2021

Rates and Regulation – Revenue Requirements

Consumers Energy
U20963-MEC-CE-662-Coker_ATT_1
Generation Balances by Site

As of 12/31/2018

Description	Construction Work in Progress	Plant in Service (i): Plant in Service	Plant in Service (i): Land	Plant in Service (i): Gross Plant Investment	(ii) Depreciation Reserve	(iii) Net Plant Balance	Rate Base
Campbell 1 & 2	9,806,590	1,051,212,380	1,159,863	1,052,372,243	305,615,791	746,756,453	756,563,043
Campbell # 3	23,772,840	1,685,970,544	1,730,079	1,687,700,622	644,433,222	1,043,267,400	1,067,040,240
Karn 1 & 2	8,693,293	1,183,122,159	178,947	1,183,301,105	253,903,812	929,397,293	938,090,586
Karn 3 & 4	12,716,262	348,009,195	50,886	348,060,081	180,881,870	167,178,211	179,894,473
Total Steam Generation	54,988,986	4,268,314,277	3,119,774	4,271,434,052	1,384,834,695	2,886,599,357	2,941,588,343

As of 12/31/2019

Description	Construction Work in Progress	Plant in Service (i): Plant in Service	Plant in Service (i): Land	Plant in Service (i): Gross Plant Investment	(ii) Depreciation Reserve	(iii) Net Plant Balance	Rate Base	(iv) Net Salvage	Depreciation Reserve	(ii) Classics Reserve Allocated	Reserve Excluding Classics
Campbell 1 & 2	14,455,737	1,053,311,870	1,159,863	1,054,471,733	424,195,955	630,275,778	644,731,515	(4,825,236)	424,195,955	(49,817,587)	474,013,542
Campbell # 3	15,970,464	1,728,866,203	1,730,079	1,730,596,282	591,809,969	1,138,786,313	1,154,756,777	(363,450)	591,809,969	(69,502,182)	661,312,151
Karn 1 & 2	7,677,542	1,191,207,867	178,947	1,191,386,813	320,944,366	870,442,447	878,119,989	(14,184,050)	320,944,366	-	320,944,366
Karn 3 & 4	9,429,195	363,956,295	50,886	364,007,181	216,512,677	147,494,504	156,923,698	49,012	216,512,677	(25,427,256)	241,939,933
Total Steam Generation	47,532,938	4,337,342,234	3,119,774	4,340,462,009	1,553,462,967	2,786,999,042	2,834,531,979	(19,323,724)	1,553,462,967	(144,747,025)	1,698,209,992

As of 12/31/2020

Description	Construction Work in Progress	Plant in Service (i): Plant in Service	Plant in Service (i): Land	Plant in Service (i): Gross Plant Investment	(ii) Depreciation Reserve	(iii) Net Plant Balance	Rate Base	(iv) Net Salvage	Depreciation Reserve	(ii) Classics Reserve Allocated	Reserve Excluding Classics
Campbell 1 & 2	5,116,291	1,086,261,505	1,159,863	1,087,421,368	461,410,535	626,010,833	631,127,124	(1,196,905)	461,410,535	(62,486,765)	523,897,300
Campbell # 3	11,833,100	1,740,508,983	1,730,079	1,742,239,062	652,272,758	1,089,966,304	1,101,799,404	(505,317)	652,272,758	(87,177,376)	739,450,134
Karn 1 & 2	2,365,770	1,200,990,690	178,947	1,201,169,637	375,792,766	825,376,871	827,742,641	(4,349,445)	375,792,766	-	375,792,766
Karn 3 & 4	2,823,238	377,720,260	50,886	377,771,146	230,064,125	147,707,021	150,530,258	(212,961)	230,064,125	(31,893,696)	261,957,821
	22,138,399	4,405,481,438	3,119,774	4,408,601,212	1,719,540,184	2,689,061,028	2,711,199,427	(6,264,628)	1,719,540,184	(181,557,837)	1,901,098,021

As of 12/31/2021 (Projected)

Description	Construction Work in Progress	Plant in Service (i): Plant in Service	Plant in Service (i): Land	Plant in Service (i): Gross Plant Investment	(ii) Depreciation Reserve	(iii) Net Plant Balance	Rate Base	(iv) Net Salvage
Campbell 1 & 2	32,254,747	1,075,630,884	1,159,863	1,076,790,748	502,169,462	574,621,285	606,876,032	(1,931,003)
Campbell # 3	26,984,056	1,723,476,872	1,730,079	1,725,206,950	719,401,520	1,005,805,430	1,032,789,486	(536,431)
Karn 1 & 2	4,533,870	1,189,247,771	178,947	1,189,426,718	420,641,026	768,785,691	773,319,561	(2,763,601)
Karn 3 & 4	16,214,370	374,027,173	50,886	374,078,059	240,280,593	133,797,466	150,011,836	(4,547,969)
Total Steam Generation	79,987,043	4,362,382,700	3,119,774	4,365,502,475	1,882,492,602	2,483,009,872	2,562,996,915	(9,779,004)

As of 12/31/2022 (Projected)

Description	Construction Work in Progress	Plant in Service (i): Plant in Service	Plant in Service (i): Land	Plant in Service (i): Gross Plant Investment	(ii) Depreciation Reserve	(iii) Net Plant Balance	Rate Base	(iv) Net Salvage
Campbell 1 & 2	44,670,390	1,070,354,610	1,159,863	1,071,514,473	549,421,176	522,093,297	566,763,688	(531,011)
Campbell # 3	54,600,892	1,715,023,358	1,730,079	1,716,753,436	794,101,948	922,651,488	977,252,380	(1,127,931)
Karn 1 & 2	5,979,370	1,183,419,580	178,947	1,183,598,527	453,440,980	730,157,547	736,136,917	(20,435,456)
Karn 3 & 4	39,876,662	372,194,191	50,886	372,245,077	250,623,406	121,621,670	161,498,332	(6,191,274)
Total Steam Generation	145,127,314	4,340,991,738	3,119,774	4,344,111,512	2,047,587,510	2,296,524,003	2,441,651,316	(28,285,672)

Consumers Energy
U20963-MEC-CE-662-Coker_ATT_1
Revenue Requirement Calcs by Site

	Campbell 1 & 2	Campbell 3	Karn 1 & 2	Karn 3 &4
2019				
Beginning Rate Base	756,563,043	1,067,040,240	938,090,586	179,894,473
Ending Rate Base	644,731,515	1,154,756,777	878,119,989	156,923,698
Average Rate Base	700,647,279	1,110,898,509	908,105,288	168,409,086
Rate of Return Post Tax	41,793,563	66,265,021	54,168,419	10,045,591
Equity Return	29,359,698	46,550,734	38,052,952	7,056,960
Interest	12,060,626	19,122,505	15,631,714	2,898,918
Taxes	10,051,164	15,936,439	13,027,261	2,415,919
2020				
Beginning Rate Base	644,731,515	1,154,756,777	878,119,989	156,923,698
Ending Rate Base	631,127,124	1,101,799,404	827,742,641	150,530,258
Average Rate Base	637,929,320	1,128,278,090	852,931,315	153,726,978
Rate of Return Post Tax	38,052,441	67,301,712	50,877,296	9,169,804
Equity Return	26,731,585	47,279,002	35,740,959	6,441,726
Interest	10,981,027	19,421,670	14,681,975	2,646,187
Taxes	9,151,441	16,185,759	12,235,760	2,205,297
2021				
Beginning Rate Base	631,127,124	1,101,799,404	827,742,641	150,530,258
Ending Rate Base	606,876,032	1,032,789,486	773,319,561	150,011,836
Average Rate Base	619,001,578	1,067,294,445	800,531,101	150,271,047
Rate of Return Post Tax	35,084,741	60,493,787	45,373,756	8,517,298
Equity Return	25,433,506	43,852,941	32,892,182	6,174,329
Interest	9,406,291	16,218,509	12,164,797	2,283,505
Taxes	8,689,879	14,983,256	11,238,288	2,109,586
2022				
Beginning Rate Base	606,876,032	1,032,789,486	773,319,561	150,011,836
Ending Rate Base	566,763,688	977,252,380	736,136,917	161,498,332
Average Rate Base	586,819,860	1,005,020,933	754,728,239	155,755,084
Rate of Return Post Tax	33,260,695	56,964,151	42,777,670	8,828,131
Equity Return	24,111,225	41,294,250	31,010,236	6,399,657
Interest	8,917,261	15,272,206	11,468,781	2,366,840
Taxes	8,238,094	14,109,027	10,595,283	2,186,574

viii. Post-tax return

	2019	2020	2021	2022
Campbell 1 & 2	41,793,563	38,052,441	35,084,741	33,260,695
Campbell 3	66,265,021	67,301,712	60,493,787	56,964,151
Karn 1 & 2	54,168,419	50,877,296	45,373,756	42,777,670
Karn 3 & 4	10,045,591	9,169,804	8,517,298	8,828,131

ix. Equity Return

	2019	2020	2021	2022
Campbell 1 & 2	29,359,698	26,731,585	25,433,506	24,111,225
Campbell 3	46,550,734	47,279,002	43,852,941	41,294,250
Karn 1 & 2	38,052,952	35,740,959	32,892,182	31,010,236
Karn 3 & 4	7,056,960	6,441,726	6,174,329	6,399,657

x. Interest

	2019	2020	2021	2022
Campbell 1 & 2	12,060,626	10,981,027	9,406,291	8,917,261
Campbell 3	19,122,505	19,421,670	16,218,509	15,272,206
Karn 1 & 2	15,631,714	14,681,975	12,164,797	11,468,781
Karn 3 & 4	2,898,918	2,646,187	2,283,505	2,366,840

xi. Taxes

	2019	2020	2021	2022
Campbell 1 & 2	10,051,164	9,151,441	8,689,879	8,238,094
Campbell 3	15,936,439	16,185,759	14,983,256	14,109,027
Karn 1 & 2	13,027,261	12,235,760	11,238,288	10,595,283
Karn 3 & 4	2,415,919	2,205,297	2,109,586	2,186,574

vii. Depreciation Expense

	2019	2020	2021	2022
Campbell 1 & 2	52,033,363	52,929,425	53,320,551	53,058,999
Campbell 3	83,732,514	84,931,189	84,697,305	84,281,873
Karn 1 & 2	59,113,578	59,554,464	59,354,481	59,063,600
Karn 3 & 4	17,512,436	18,265,244	18,457,524	18,367,070

xii. Property Taxes

	2019	2020	2021	2022
Karn 1-2	2,647,000	2,166,000	1,476,000	923,000
Karn 3-4	1,373,000	1,434,000	1,454,000	1,486,000
Campbell 1-2	819,000	655,000	386,000	272,000
Campbell 3	4,265,000	3,862,000	3,291,000	3,291,000

xii. O&M

	2019	2020	2021	2022
Karn 1-2	34,324,240	27,127,373	25,067,121	26,172,534
Karn 3-4	9,209,212	14,101,799	8,555,652	10,839,058
Campbell 1-2	19,182,334	23,037,951	28,127,077	24,715,427
Campbell 3	21,992,684	22,008,996	28,985,050	29,563,754

Michigan Public Service Commission
Consumers Energy Company
Overall Rate of Return Summary
Projected Capital Structure & Cost Rates
Projected 12 Month Period Ending December 31, 2019

	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				13-Month	% of	% of		Weighted Cost			
Line				Average	Permanent	Total	Cost	Permanent	Total	of	Pre-Tax
No.	Description	Source		($000)	Capital	Capital	Rate	Capital	Capital	Debt	Basis
1	Long Term Debt	WP-HJM-116	$	6,692,616	47.24%	37.71%	4.47%	2.11%	1.69%	1.69%	1.69%
2	Preferred Stock	WP-HJM-116	$	37,315	0.26%	0.21%	4.50%	0.01%	0.01%		0.01%
3	Common Equity	WP-HJM-116	$	7,437,782	52.50%	41.90%	10.00%	5.25%	4.19%		5.61%
4	Permanent Capital		$	14,167,713	100.00%			7.37%			
5	Total Short Term Debt	WP-HJM-116	$	154,000		0.87%	4.14%		0.04%	0.04%	0.04%
6	Deferred FIT	WP-HJM-116	$	3,322,000		18.72%	0.00%		0.00%		0.00%
	Deferred JDITC/ITC										
7	Long Term Debt	WP-HJM-116	$	50,780		0.29%	4.47%		0.01%	0.01%	0.01%
8	Preferred Stock	WP-HJM-116	$	283		0.00%	4.50%		0.00%		0.00%
9	Common Equity	WP-HJM-116	$	54,936		0.31%	10.00%		0.03%		0.04%
10	Total Capitalization		$	17,749,712		100.00%			5.96%	1.73%	7.40%

Michigan Public Service Commission
Consumers Energy Company
Overall Rate of Return Summary
Projected Capital Structure & Cost Rates
Projected 12 Month Period Ending December 31, 2021

1.3391

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			13-Month	% of	% of		Weighted Cost			
Line No.	Description	Source	Average ($000)	Permanent Capital	Total Capital	Cost Rate	Permanent Capital	Total Capital	of Debt	Pre-Tax Basis
1	Long Term Debt	WP-HJM-75	$ 8,178,497	48.67%	39.53%	3.81%	1.85%	1.51%	1.51%	1.51%
2	Preferred Stock	WP-HJM-75	$ 37,315	0.22%	0.18%	4.50%	0.01%	0.01%		0.01%
3	Common Equity	WP-HJM-75	$ 8,587,377	51.11%	41.50%	9.90%	5.06%	4.11%		5.50%
4	Permanent Capital		$ 16,803,189	100.00%						
5	Total Short Term Debt	WP-HJM-75	$ 138,800		0.67%	2.03%		0.01%	0.01%	0.01%
6	Deferred FIT	WP-HJM-75	$ 3,655,000		17.66%	0.00%		0.00%		0.00%
	Deferred JDITC/ITC									
7	Long Term Debt	WP-HJM-75	$ 45,752		0.22%	3.81%		0.01%	0.01%	0.01%
8	Preferred Stock	WP-HJM-75	$ 209		0.00%	4.50%		0.00%		0.00%
9	Common Equity	WP-HJM-75	$ 48,039		0.23%	9.90%		0.02%		0.03%
10	Total Capitalization		$ 20,690,989		100.00%			5.67%	1.53%	7.07%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected Rate of Return Summary

For the Projected 12-Month Period Ending December 31, 2022

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		Capital Structure				**Weighted Cost**			
Line No	**Description**	**($000) {1}**	**Percent Permanent Capital**	**Percent of Total Capital**	**Cost Rate % {1}**	**Permanent Capital**	**Total Cost %**	**Conversion Factor**	**Pre-Tax Return**
1	Long Term Debt	9,072,264	47.80%	39.34%	3.55%	1.70%	1.40%		1.40%
2	Preferred Stock	37,315	0.20%	0.16%	4.50%	0.01%	0.01%	1.3391	0.01%
3	Common Equity	9,869,545	52.00%	42.80%	10.50%	5.46%	4.49%	1.3391	6.02%
4	Permanent Capital	18,979,124							
5	Total Short Term Debt	199,946		0.87%	1.15%		0.01%		0.01%
6	Deferred FIT	3,751,125		16.27%	0.00%		0.00%		0.00%
7	Deferred JDITC - Long Term Debt	61,558		0.27%	3.55%		0.01%		0.01%
8	Deferred JDITC - Preferred Stock	330		0.00%	4.50%		0.00%	1.3391	0.00%
9	Deferred JDITC - Common Equity	68,170		0.30%	10.50%		0.03%	1.3391	0.04%
10	Total	23,060,254					5.95%		7.48%

Notes

{1} Source: Exhibit No.: A-14 (MRB-1)

Question:

28. For each of the Company's coal units, and for Karn units 3 and 4:

   a. Please provide the annual revenue requirements for 2021 and 2022 for each unit, including a breakdown of:

      i. Gross plant balance

      ii. Accumulated depreciation balance

      iii. Net plant balance

      iv. Net salvage (or negative net salvage)

      v. The identification and quantification of any other category of expense collected through depreciation expense (e.g. asset retirement obligations, remediation accounts, etc.).

      vi. Estimated end-of-useful life date for purposes of setting a depreciation schedule.

      vii. The annual depreciation expense attributable to the generating unit.

      viii. Rate of return

      ix. Equity return

      x. Interest

      xi. Taxes

      xii. Any other category of costs that factors into the calculation of the unit's revenue requirement.

   b. Please identify how common area or plant-wide costs are allocated (i.e., the percentage assigned to each unit) between each of the following in calculating the revenue requirement.

      i. any common areas for Campbell Units 1 and 2;

      ii. any common areas for the entire Campbell plant (including the cost allocation between Campbell 1&2 and Campbell 3);

      iii. any common areas for Karn Units 1 and 2;

      iv. any common areas for the entire Karn plant (including the cost allocation between Karn 1&2 and Karn 3&4).

Note: In providing the requested information, please provide the depreciation balances, depreciation expenses, etc., that are specifically attributable to the Campbell and Karn units. (In other words, please provide information – including but not limited to depreciation balances – that exclude the unrecovered decommissioning costs attributable to the Classic 7.)

Note: If the Company does not have unit-level information for a particular cost category, please provide the most disaggregated data available

Note: Please provide the requested cost information in machine-readable electronic format, with formulas intact, along with supporting workpapers.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request because it seeks information that is irrelevant, overly broad, and not proportional to the needs of this case. The Company also objects to this discovery request to the extent it calls for the creation of documents, data, and analyses which currently do not exist. Subject to that objection, and without waiving it, the Company provides the following response:

a. Breakdown of annual revenue requirements for 2021 and 2022 for each unit:

   i. Gross plant balance: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 1.

   ii. Accumulated depreciation balance: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 1.

   iii. Net plant balance: Please see attachment U20963-MEC-CE-662-Coker_ATT_1.

   iv. Net salvage (or negative net salvage) : Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 1. The amounts in the file reflect the amount of salvage received less the cost of removal spent in each year. The amounts shown in the attached file only reflect the negative net salvage attributable to the requested units. However, the net salvage attributable to the previously retired steam plants are allocated across the remaining sites.

   v. See response to U20963-MEC-CE-662.

   vi. See response to U20963-MEC-CE-662.

   vii. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

   viii. Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2 for the post-tax return.

   ix. Equity return: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

   x. Interest: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

   xi. Taxes: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2.

   xii. Any other category of costs that factors into the calculation of the unit's revenue requirement: Please see attachment U20963-MEC-CE-662-Coker_ATT_1, page 2 for property taxes and O&M by generation site.

b. See response to U20963-MEC-CE-662.

Jason R. Coker
May 14, 2021

Question:

29. Has Consumers forecasted the coal units' revenue requirements for any of the years 2023-25? If so, please provide such forecasts, including a breakdown of the cost categories listed in the previous discovery request.

Response:

Consumers Energy has not forecasted the coal units' revenue requirements for any of the years 2023-2025.

Jason R. Coker
May 14, 2021

Rates and Regulation – Revenue Requirements

Question:

12. Refer to MEC-CE-662(b) and -663(b), which asked the Company to identify how certain common area or plant-wide costs were allocated between the Campbell and Karn units, and to your responses.

a. Refer to your response to -662(b)(i), which states that "[t]he Company does not separate Campbell Units 1 and 2." Further refer to U20697-MEC-CE-528(b)(i) and U20697-MEC-CE-529(b)(i), which asked an identical question in last year's rate case, and to your responses, which state: "Common areas for Campbell Units 1 and 2 are split 42% for Campbell Unit 1 and 58% for Campbell Unit 2 based upon unit capacity."

   i. Please confirm that costs for Campbell 1&2 common areas are split 42% for Campbell 1 and 58% for Campbell 2. If not confirmed:

      Please reconcile your answer with the responses to U20697-MEC-CE- 528(b)(i) and U20697-MEC-CE-529(b)(i) in Case No. U-20697.

      Please identify how costs for Campbell 1&2 common areas are allocated between the two units. If these allocations changed over time, please specify that in your response.

b. Refer to your response to -662(b)(ii), which states: "The common area assets are primarily allocated 43% to Campbell 1 & 2 and 57% to Campbell 3. However, certain projects may be allocated differently." Further refer to U20697-MEC-CE- 528(b)(ii) and U20697-MEC-CE-529(b)(ii), which asked an identical question in last year's rate case, and to your responses, which state: "Common areas for Campbell site are split 57% for Campbell Unit 3 and 43% for Campbell Units 1 and 2."

   i. Please explain why the Company qualified its response to this question in MEC-CE-662(b)(ii) – i.e., stating that "certain projects may be allocated differently."

   ii. For any of the years 2019-2025, are there any capital or major maintenance Campbell common area projects that were performed, are planned, or under consideration whose costs would be allocated differently than a 57/43 split?

      If so, please identify each such project, including the Work ID and project description, the actual or projected cost for each of the years 2019-2025, the allocation applied to each project, and an explanation and rationale for the allocation.

   iii. Further refer to U20963-MEC-CE-013_ATT_44, which lists a number of capital, major maintenance, and Normals (O&M) costs for the Campbell Site Commons in the years 2021 through 2025. Does the Company intend to allocate any of these costs differently than a 57/43 split between Campbell 3 and Campbell 1&2?

      If so, please identify each such cost. For capital and major maintenance expenditures, please identify the Work ID, project description, the actual or projected cost for each of the years 2021-2025, the allocation applied to each project, and an explanation and rationale for the allocation.

Response:

a.
  i. The response to U-20963-MEC-CE-662(b)(i) was incorrect. Common area costs are allocated 42% to Campbell 1 and 58% to Campbell 2, based upon unit capacity.

b.
  i. There may be a reason for a project to be split differently than the general allocation if specific circumstances provide a better justification for some other allocation.
  ii. We expect costs for all projects performed, planned, or under consideration for years 2019-2025 would be allocated 57/43.
  iii. We expect costs for all projects performed, planned, or under consideration for years 2021-2025 would be allocated 57/43.

Jason R. Coker
June 4, 2021

Rates and Regulation – Revenue Requirements

Question:

19. Refer to U20963-MEC-CE-662-Coker_ATT_1 and U20697-MEC-CE-1022-Hugo_ATT_1.

   a. Please explain why the Company reported in Case No. U-20697 that O&M costs for Campbell 1-2 combined in 2019 was $22,843,417 (U20697-MEC-CE-1022- Hugo_ATT_1), but in the current case reported this O&M cost to be $19,182,334.

      i. Please provide the correct O&M for Campbell 1 and 2 combined, and individually if available.

      ii. If the O&M costs reported for Campbell 1 or Campbell 2 in "U20963-MEC- CE-010_ATT_1 2nd Revised" or "U20963-MEC-CE-011_ATT_1 2nd Revised" are incorrect, please provide updated versions of those O&M figures.

Response:

   a. The 2019 O&M costs for Campbell 1 and 2 included in U20697-ME-CE-1022_ATT_1 were projected. They included 9 months of actual costs and 3 months of projected costs. The amounts reported in U20963-MEC-CE-662-Coker_ATT_1 are 2019 actual costs.

      i. The correct O&M for Campbell 1 and 2 is included in 20963-MEC-CE-662.

      ii. The correct O&M for Campbell 1 and 2 is included in 20963-MEC-CE-662.

Jason R. Coker
June 4, 2021

Rates and Regulation – Revenue Requirements

<u>Question:</u>

20. Refer to U20963-MEC-CE-662-Coker_ATT_1 and U20697-MEC-CE-1370- Hugo_ATT_1.

    a. Please explain why the Company reported in Case No. U-20697 that the depreciation reserve for Campbell 1-2 combined in 2018 was $332,523,074 (U20697-MEC-CE-1370-Hugo_ATT_1), but in the current case reported $305,615,791.

        i. Please provide the correct depreciation reserve for 2018 for Campbell 1-2 combined.

    b. Please explain why the Company reported in Case No. U-20697 that the depreciation reserve for Campbell 1-2 combined (excluding the Classic 7) in 2019 was $378,377,389 (U20697-MEC-CE-1370-Hugo_ATT_1), but in the current case reported $474,013,542.

        i. Please provide the correct depreciation reserve for 2019 for Campbell 1-2 combined.

    c. Please provide corrected 2020, 2021 and 2022 revenue requirements data if the data provided in U20963-MEC-CE-662-Coker_ATT_1 are incorrect.

    d. Please provide corrected calculations of the following, given any corrections above:

        i. Starting and end of year rate base

        ii. Post-tax return

        iii. Income taxes

        iv. Depreciation expense

    e. Please confirm any data mentioned above is correct, if it was not corrected in the responses above.

<u>Response:</u>

a. The $332,523,074 referenced in U20697-MEC-CE-1370-Hugo_ATT_1 excludes the allocation of the Classic 7 balances, as requested by MEC. The $305,615,791 in the current case includes the allocation of the Classic 7 balances.

    i. Both balances referenced are correct

b. The 2019 Campbell 1-2 depreciation reserve reported in this case is different from the amount reported in U-20697 because the Company has reallocated the 2019 depreciation reserves between the Campbell 1-2, Campbell 3, and Karn 3-4 units as part of U-20849, the Company's electric and common depreciation case filed on 3/1/2021. The reallocation of depreciation reserves is common practice in utility depreciation and has been done in the Company's previous depreciation filings. Because the Company's depreciation rates in previous cases were approved at a composite level rather than separate rates for each site, it is appropriate to reallocate the reserves to better reflect each sites' balance.

i. The amounts presented U20963-MEC-CE-662-Coker_ATT_1 are correct.

c. The amounts presented U20963-MEC-CE-662-Coker_ATT_1 are correct.

d. The amounts presented U20963-MEC-CE-662-Coker_ATT_1 are correct.

e. The amounts presented U20963-MEC-CE-662-Coker_ATT_1 are correct.

Jason R. Coker
June 4, 2021

Rates and Regulation – Revenue Requirements

MEC-54C

CONFIDENTIAL EXHIBIT

Capacity Factors, Availability, Periodic Factors, and Random Outage Rates for Campbell units 1 and 2

Capacity factor *Actual and CE 2021 projection*	**actual**						**CE 2021 projection**				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Campbell 1	67%	53%	43%	51%	64%	32%	69%	74%	63%	62%	50%
Campbell 2	53%	52%	38%	44%	54%	26%	50%	64%	50%	47%	35%

Availability *Actual and CE 2021 projection*	**actual**						**CE 2021 projection**				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Campbell 1	82%	77%	71%	78%	74%	48%	71%	76%	72%	71%	75%
Campbell 2	75%	70%	61%	71%	63%	68%	56%	65%	66%	64%	64%

Periodic factor *Actual and CE 2021 projection*	**actual**						**CE 2021 projection**				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Campbell 1	8%	11%	14%	14%	14%	36%	12%	6%	12%	13%	6%
Campbell 2	22%	23%	12%	21%	18%	20%	23%	12%	11%	13%	13%

Random outage rate *Actual and CE 2021 projection*	**actual**						**CE 2021 projection**				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Campbell 1	11%	14%	18%	10%	14%	25%	16%	16%	16%	16%	17%
Campbell 2	3%	9%	30%	11%	23%	15%	14%	15%	15%	15%	15%

Source *U20697 CE-1022 ATT 1* *MEC-CE-010_Hugo_Att_1 & MEC-CE-011_Hugo_Att_1*

Campbell Capital Expenditures -- Recommended Disallowances

2021 avoidable capital expenditures at Campbell Units 1 and 2; disallowed by the Commission in previous rate case (U-20697)

Unit	Project ID	2021 spending	2022 spending
Campbell 2	5573 -JHC2 Overhaul CCWP & Motors	$580,000	
Campbell 2	5577 -JHC2 - Overhaul JHC2 FD Fan Motors	$402,000	
Campbell 2	5462 -JHC2 SAH Baskets and Seals	$2,735,000	
TOTAL		**$3,717,000**	

2022 capital costs at Campbell 1 and 2 that are avoidable with a 2024 or 2025 Retirement

Unit	Project ID	2021 spending	2022 spending
Campbell 1	5589 -JHC1 SH Outlet Pendant Tube Panel Replacements		$20,000
Campbell 1	5665 -JHC1 Ashpit Replacement		$432,000
Campbell 1&2	5538 -JHC 1&2 - 316B Deep Water Intake		$500,000
TOTAL			**$952,000**

Steam Electric Effluent Guidelines (SEEG) Compliance Costs

Unit	Project ID	2021 spending	2022 spending
Campbell Commons	5523 -JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.	$1,928,742	$15,421,498
TOTAL		**$1,928,742**	**$15,421,498**

Capital expenditures above $100,000 that have inadequate supporting documentation (2021 costs that were previously disallowed are underlined)

Unit	Project ID	2021 spending	2022 spending	Reason *(Source)*
Campbell 1	5543 -JHC1 Mill Overhaul	$696,000		No supporting docs (MEC-CE-983)
Campbell 1	9650 -JHC1 Major Motor and Pump Overhauls	$200,000	$200,000	No supporting docs (MEC-CE-983)
Campbell 1	9653 -JHC1 Balance of Plant Equipment	$135,000	$135,000	No supporting docs (MEC-CE-983)
Campbell 1	9655 -JHC1 AQCS Projects	$250,000	$250,000	No supporting docs (MEC-CE-983)
Campbell 2	3089 -JHC2 Mill Overhauls (grinding section & gearbox)	$400,000		No supporting docs (MEC-CE-983)
Campbell 2	5594 -JHC2 Main BFP overhaul	$359,000		No supporting docs (MEC-CE-983)
Campbell 2	5663 -JHC 2 2A Condensate Pump Overhaul	$210,000		No supporting docs (MEC-CE-983)
Campbell 2	9651 -JHC2 Major Motor and Pump Overhauls	$200,000	$200,000	No supporting docs (MEC-CE-983)
Campbell 2	9654 -JHC2 Balance of Plant Equipment Replacements	$135,000	$135,000	No supporting docs (MEC-CE-983)
Campbell 2	9656 -JHC2 AQCS Projects	$250,000	$250,000	No supporting docs (MEC-CE-983)
Campbell 3	5691 -JHC3 Replace O2 monitors	$944,600	$904,600	No supporting docs (MEC-CE-983)
Campbell 3	5693 -JHC3 Mill Complete Overhauls	$1,335,000	$1,264,800	No supporting docs (MEC-CE-983)
Campbell 3	5708 -JHC3 Sootblowing Air Compressor Controls		$250,000	Significant cost discrepancy (MEC-CE-987(g)
Campbell 3	5749 -JHC3 Replace Boiler Sidewall Panels*		$25,000	No econ assessment (MEC-CE-644)
Campbell 3	5750 -JHC3 Replace Boiler Front And Rear Wall Panels*		$25,000	No econ assessment (MEC-CE-644)
Campbell 3	9671 -JHC Fuel Handling/ Infrastructure Replacements	$500,000	$750,000	No supporting docs (MEC-CE-983)
Campbell 3	9689 -JHC3 Major Motor and Pump Overhauls		$400,000	No supporting docs (MEC-CE-983)
Campbell 3	9690 -JHC3 Balance of Plant Equipment Replacements	$180,000	$180,000	No supporting docs (MEC-CE-983)
Campbell 3	9692 -JHC3 AQCS Projects	$250,000	$250,000	No supporting docs (MEC-CE-983)
Campbell 3	10257 -JHC3 FD fan vibration monitor equipment replacement	$251,400		Significant cost discrepancy (MEC-CE-987(e)
Campbell 3	11249 -JHC3 Boiler Roof Replacement	$50,000	$2,606,000	Significant cost discrepancy (MEC-CE-987(f))
Campbell Commons	5480 -JHC FH Replace Fuel Handling Conveyor Belts	$427,000		No supporting docs (MEC-CE-983)
Campbell Commons	9397 -JHC Dry Ash Landfill Closure		$288,570	No supporting docs (MEC-CE-983)
TOTAL		**$6,773,000**	**$8,113,970**	

*these projects have less than $100,000 in spending in 2022 but substantially more than $100,000 spending in future years.

Capital projects with inadequate economic analyses
(2021 costs that were previously disallowed are underlined)

Unit	Project ID	2021 spending	2022 spending	Reason *(Source)*
Campbell 3	5707 -JHC3 Reheater Sootblower	$1,350,000		*flawed econ assessment (see Comings Direct pp. 55-56)*
Campbell 3	9526 -JHC3 Replace ABB Damper Drives	$79,000	$590,000	*flawed econ assessment (see Comings Direct pp. 55-56)*
Campbell Commons	10730 -JHC Ash Silo Secondary Electrical Source	$30,000	$601,000	*flawed econ assessment (see Comings Direct pp. 55-56)*
TOTAL		**$1,459,000**	**$1,191,000**	

U20963-MEC-CE-013 (Revised)
Page **1** of **3**

Question:

6. 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 each capital and major maintenance project that was performed, is planned, or is under consideration for any of the years 2019 through 2025. Please provide this information in a spreadsheet format, with any formulas intact, and include the following information:
i. the unit and/or common area where such project was or would be performed;
ii. the Work ID and project description (e.g., "5566 - JHC 2 PJFF bag replacement);
iii. the actual or projected cost for each of the years 2019-2025;
iv. the project's Approval Criteria category (e.g., economic, safety/compliance/regulatory, etc.)
v. for projects that have expenditures in any of the years 2021-2025, please identify whether those expenditures would be avoidable under the 2024 and 2025 Campbell Units 1 and/or 2 retirement scenarios identified in Exhibit A-94 (SAH-4).1 (This include projects that the Company is currently performing: if a project is already underway, but would have been avoidable under any of the 2024 and 2025 retirement scenario, please identify it.)
c. For each capital and major maintenance project identified in subpart b, please:
i. Produce any project charter, project scope document, economic analysis, and/or other written evaluation of the costs and benefits of such project.
ii. Identify the Internal Rate of Return ("IRR") and Present Value Ratio ("PVR").
(a) Please provide a copy of the IRR or PVR analysis in machine-readable electronic format, with formulas intact. Please also produce, in machine-readable electronic format with formulas intact, all workpapers and modeling files created, used, or relied on in calculating such IRR and PVR.
(b) 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.

(footnote 1 For reference, this subpart seeks information similar to what the Company provided in Case No. U-20967. In that case, the Company identified avoidable capital and major maintenance expenditures in several spreadsheets produced in discovery, including: U20697-MEC-CE-544_ATT_1, U20697-MEC-CE-545-Hugo_ATT_1, and U20697-MEC-CE-1014_ATT_1.)

Response:

a. See Attachment U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_45. The forecast attachments include the years 2019-2025, which reflects all approved projects. Projects for 2026-2031 have neither been submitted or approved and, therefore, are not available.

i. See Attachment U20963-MEC-CE-013_ATT_44 (Cap Non-Env (i)) and U20963-MEC-CE-013_ATT_45 (Cap Non-Env (i))
ii. See Attachment U20963-MEC-CE-013_ATT_44 (Cap Env (ii)) and U20963-MEC-CE-013_ATT_45 (Cap Env (ii))
iii. See Attachment U20963-MEC-CE-013_ATT_44 (MM (iii)) and U20963-MEC-CE-013_ATT_45 (MM (iii))
iv. See Attachment U20963-MEC-CE-013_ATT_44 (Normals (iv)) and U20963-MEC-CE-013_ATT_45 (Normals (iv))

b. See Attachment U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_45.
   i. Included in attachments
   ii. Included in attachments
   iii. Included in attachments
   iv. Included in attachments
   v. Items listed as avoidable are included in the Discovery Responses 20963-MEC-CE-023 and 20963-MEC-CE-024.

c. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request to the extent that it is irrelevant, unclear, overly broad, and not proportional to the needs of this case. The Company also objects to this request to the extent that it seeks confidential business information. The disclosure of such information could cause harm to the Company and its customers. The requested confidential business information will only be provided subsequent to the execution of a suitable confidentiality and nondisclosure agreement. Subject to that objection, and without waiving it, the Company provides the following response:**

   i. Included in attachment U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_45 are the problem statements of each project. Additionally, attachments U20963-MEC-CE-013_ATT_2 through U20963-MEC-CE-013_ATT_37 are project charters or concept approvals for all but 3 projects from 2019-2022 greater than $1,000,000. Attachment U20963-MEC-CE-013_ATT_1 summarizes the included attachments.
   ii.
      (a) Items that have IRRs calculated for 2019-2021 were submitted in case U-20697 and both requested and included in the Company's response to U20963-MEC-CE-008. Additional items that have had IRRs calculated are included in confidential attachments U20963-MEC-CE-013_ATT_38 through U20963-MEC-CE-013_ATT_43 **<u>Confidential</u>**. The following items are considered economic and have studies funded in 2021 and/or 2022. Within these studies the equipment will be assessed for confirmation of need, forecasts refined, benefits confirmed, and economics ran. They are not available currently.
      5589-JHC1 SH Outlet Pendant Tube Panel Replacements
      5692 -JHC3 SH Terminal Tube Replacement PT-01685
      5749 -JHC3 Replace Boiler Sidewall Panels
      5750 -JHC3 Replace Boiler Front And Rear Wall Panels

5753 -JHC3 8A HPH Replacement

(b) Items not included in section (a) do not have an economic evaluation included. IRRs or PVRs are not typically calculated for "equipment condition" or condition-based projects. As discussed on pages 34-35 of my direct testimony, the Company does not calculate IRRs or PVRs for all projects, rather it only calculates IRRs or PVRs for economic projects. Economic projects are those projects that are expected to improve the reliability, efficiency or availability of a generating unit, thereby reducing customer expense as a result of having implemented the project. The Company does not calculate IRRs or PVRs for projects that are required for regulatory, compliance, safety and/or continued operations unless the Company is trying to identify the least-cost alternative for the project. Condition-based projects are intended to restore the equipment to its original condition. And while condition-based projects do improve equipment reliability, efficiency or availability of a generating unit relative to the current condition of the equipment for which the project is being implemented, a key goal of those projects is to reduce the risk of equipment failure. The failure to calculate a IRR or PVR does not indicate that a project would not be found to be cost-effective. Regulatory and safety projects provide value in ensuring the Company can comply with regulations and that the employees have a safe environment in which to work. Condition-based or reliability projects, while not considered economic projects, help ensure that equipment performs as expected and does not fail prematurely. The failure to perform these projects can and will result in incremental customer costs due to equipment failure and inefficient equipment performance. Most projects fall in the category of regulatory, safety and reliability.

Revised Response:

This response is being revised to provide additional attachments. Please see the folder labeled "U20963-MEC-CE-013 Supplemental Attachments" that can be found on Consumers Energy Company's SharePoint site.

Scott A. Hugo
May 19, 2021

Director – Generation Asset Strategy

Question:

16. Refer to page 105, line 8 through page 111, line 20 of the Hugo Direct Testimony and Exhibit A-94 (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:

      1. Please describe in detail the steps you took to evaluate whether each such project would be avoidable in a 2024 or 2025 retirement scenario.

      2. Please explain why each such expenditure is purportedly unavoidable in a 2024 or 2025 retirement scenario.

      3. Please produce all analyses, reports, and other documents created, used, or relied on in evaluating whether these projects are avoidable.

   ii. Please identify each specific project and its cost that is included in the Incremental capital expenditures, and provide the following information:

      1. Please explain what steps you took to evaluate whether each such project would be incremental in a 2024 or 2025 retirement scenario.

      2. Please explain why each such expenditure is purportedly incremental in a 2024 or 2025 retirement scenario.

      3. 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 2023-2025 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:

a.

   i. See attachment U20963-MEC-CE-023_ATT_1 for listing of projects and status reasoning.

1. The approach taken to develop the decision to identify a project as avoidable or unavoidable is based on the philosophy of running the units in a safe, regulatory compliant manner through end of life and allowing for reasonable decrease in availability and reliability. Ultimately these units need to continue to serve our customers when required. There are four main reasons for declaring projects as unavoidable in the attachment; regulatory, reliability, site commons and Unit 3. Regulatory status are those projects required to run the unit within our constraints set by our Renewable Operating Permit, boiler code, NERC, FERC, etc. Reliability projects are those that will maintain unit availability through end of life. Projects labeled Commons are required for site operations for which the costs are distributed to the individual units based on MW percentages. Finally, the Unit 3 projects are those that are for JH Campbell 3.
2. For Campbell 1:
    - 9194 – Regulatory – This project is to maintain compliance with Particulate Matter Continuous Emissions Monitoring Systems (PM-CEMS)
    - 9655 – Regulatory – This project is to maintain compliance with NOx regulations
    - 9372 – Reliability – The Unit 1A Condensate Pump Overhaul has indications that require an overhaul.
    - 9650 & 9653 – Reliability – These projects are for emergent equipment failures during operation.

   For Campbell 2:
    - 9656 – Regulatory – This project is to maintain compliance with NOx regulations
    - 9651 & 9654 – Reliability – These projects are for emergent equipment failures during operation.

   For Campbell 3:
    - All items – Unit 3 – These projects are for JHCampbell 3 operation

   For Campbell Fuel Handling and Campbell Site Commons:
    - All items – Commons – These projects are for JHCampbell Site operation
3. Hugo_WP_1_51_ERC (WP-50) is the workpaper utilized to create Exhibit A-94 (SAH-4).

ii.

1. The incremental costs are based on utilizing the confidential study in the attachment included in the Company's response to U20963-MEC-CE-14 and Hugo_WP_1_51_ERC (WP-51).
2. The costs are based on general timeline to effectively engineer, procure and construct in preparation for early retirement. The experience the Company has with Karn 1-4 was used to establish this basic timeline. The costs identified in Exhibit A-94 (SAH-4) do not completely match Hugo_WP_1_51_ERC (WP-51) due to the timing of the case. The workpaper shows funding landing in 2020 and 2021 which is not reasonable as the case will not be completed until the end of 2021. Therefore, the costs that are in 2022 for the 2025 Early Retirement scenario were used for both scenarios.

3. The incremental costs are based on utilizing the confidential study in the attachment included in the response to U20963-MEC-CE-14 and Hugo_WP_1_51_ERC (WP-51).

b.

<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is irrelevant, overly broad, and not proportional to the needs of this case. objects to this discovery request to the extent it calls for the creation of documents, data, and analyses which currently do not exist. The Company has no obligation to create such documents, data, and analyses for the purposes of discovery. Subject to that objection, and without waiving it, the Company provides the following response:

The requirement for the rate case was to examine the avoidable and unavoidable cost for the test year only. Additional reviews for 2023-2025 was not completed.

Scott A. Hugo
April 13, 2021

Director – Generation Asset Strategy

Question:

9. Refer to your response to MEC-CE-13(c)(ii)(a), which discusses projects 5589, 5692, 5749, and 5750. Please provide the following information for each of these projects:

a. Please identify the date when the Company plans to complete an economic assessment.
b. Please state whether the planned spending in 2021 or 2022 is limited to the costs of conducting an economic assessment.
    i. If a portion of the 2021-22 spending is for something other than the economic assessment, please describe the purpose of those expenditures.
c. If the economic assessment shows that the project is not economically beneficial, will the Company cancel the project? If not, please explain why not.

Response:

a. Projects 5692, 5749 and 5750 are related to boiler tube replacements for JH Campbell Unit 3 and 5589 is related to boiler tube replacement for JH Campbell Unit 1. The plan for 2021 is to perform condition assessments during the periodic outages. JH Campbell Unit 3's periodic outage is currently underway and JH Campbell Unit 1's periodic outage is scheduled for the fall. After the assessment, the project team will compile the findings along with cost estimates to determine the overall benefit. The expectation for 5749 and 5750 is that the project evaluations will be completed by the end of the year and the 5692 and 5589 project evaluations will be completed by 1st quarter of 2022.
b. The projected 2022 spend for projects 5589 and 5692 are for this evaluation only. With respect to projects 5749 and 5750, the projected 2021 spend is for the evaluation and the projected 2022 spend is for engineering.
    i. The funding for 5749 and 5750 is to complete engineering packages and to assemble bid scopes to bid the work.
c. The Company will cancel if the project is not economically beneficial to the customer. If the Company finds that the project does provide value to the customer, but the inspection shows that there is life left in the equipment, the project may be deferred based on the estimated life remaining.

Scott A. Hugo
May 13, 2021

Director – Generation Asset Strategy

Question:

12. Refer to your response to MEC-CE-13(b)(v), including the two discovery attachments referenced in your response. Following is a list of capital or major maintenance projects planned for 2022 at Campbell, each of which the Company has designated as unavoidable under the 2024 and 2025 Campbell 1&2 retirement scenarios.

a. Please explain why "9194 -JHC1 PJFF Filter Bag Replacement" is designated as unavoidable.

   i. Please provide any analyses or other documents supporting this designation.

b. Please explain why "9650 -JHC1 Major Motor and Pump Overhauls" is designated as unavoidable.

   i. Please provide any analyses or other documents supporting this designation.

c. Please explain why "9653 -JHC1 Balance of Plant Equipment Replacements" is designated as unavoidable.

   i. Please provide any analyses or other documents supporting this designation.

d. Please explain why "5596 -JHC1-2 Breaker Maintenance" is designated as unavoidable.

   i. Please provide any analyses or other documents supporting this designation.

e. Please explain why "5597 -JHC1&2 Medium Voltage Breaker Inspection & Cleaning" is designated as unavoidable.

   i. Please provide any analyses or other documents supporting this designation.

Response:

a. Project no. 9194 is unavoidable because it is an environmental compliance regulatory requirement.

   i. As stated in my response in MEC-CE-23(a)(i)(1), the approach taken to develop the decision to identify a project as avoidable or unavoidable is based on the philosophy of running the units in a safe, regulatory compliant manner through end of life and allowing for a reasonable decrease in availability and reliability.

b. Project no. 9650 is unavoidable because not investing in the pumps and motors will result in failures causing derates and outages that could significantly reduce unit availability and reliability.

   i. See response in subpart (a)(i)

c. Project no. 9653 is unavoidable because not investing in the balance of plant equipment will result in equipment failures causing derates and outages that could significantly reduce unit availability and reliability.

   i. See response in subpart (a)(i)

d. Project no. 5596 is unavoidable because not preforming breaker overhauls could result in breaker failures that may result in injury or death of personnel or equipment failures causing derates and outages that could significantly reduce unit availability and reliability.

   i. See response in subpart (a)(i)

e. Project no. 5597 is unavoidable because not preforming breaker overhauls could result in breaker failures that may result in injury or death of personnel or equipment failures causing derates and outages that could significantly reduce unit availability and reliability.

   i. See response in subpart (a)(i)

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

Question:

1. Refer to your response to MEC-CE-13(c), including the documents produced with or identified in your initial response and supplemental response. Based on the information provided in this response, there appears to be no internal rate of return ("IRR"), present value ratio ("PVR"), project charter, scope document, or other supporting document for the following capital projects planned for Campbell in 2021 and/or 2022: project nos. 9655, 5538, 8615, 9656, 9692, 5457, 9397, 5543, 5665, 9650, 9653, 3089, 5465, 5474, 5475, 5577, 5594, 5627, 5663, 9651, 9654, 5673, 5691, 5693, 5702, 9671, 9689, 9690, 5480, 5481, 5482, 5530, and 8250.

a. Please confirm that these capital projects planned for 2021 and/or 2022 do not currently have supporting documentation.

   i. If not confirmed, please identify and provide any documentation supporting these projects.

b. For those projects that do not have supporting documentation, please confirm that any rationale/support for these projects would be found in either (i) the "Problem" columns of the "Cap Non-Env" and "Cap Env" tabs in U20963-MEC-CE- 013_ATT_44, or (ii) on pages 46-65 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 U20963-MEC-CE-013_ATT_44.

Response:

a. Confirmed, the Company does not currently have additional supporting documents but is in the process of preparing a scope document for the Campbell Unit 3 mill overhauls. Towards that end, an overview of the scope related to the mill overhauls at Campbell is provided below.

A mill overhaul refers to the refurbishment of the various sections of a coal mill. The coal mill "grinds" the incoming coal into a fine powder so that it can be easily combusted in the boiler. Coal mills experience significant wear and require periodic maintenance to ensure the fineness of the coal and the efficiency of the boiler. The typical scopes of work for a mill overhaul at Campbell Units 2 and 3.

JHC-2 MILL OVERHAUL

Gear and grinding section overhaul
●Upper and lower grinding ring replacement
●Ball replacement
●Internal housing repairs
●Spring replacement
●Internal liner replacement
●Yoke and main shaft replacement
●Bull gear replacement

●Pinion gear and bearing assembly replacement
●1600 man hours (8 weeks with 5 employees)

Grinding section overhaul
●Upper and lower grinding ring replacement
●Ball replacement
●Internal housing repairs
●Spring replacement
●800 man hours (4 weeks with 5 employees)

JHC-3 MILL OVERHAUL

Grinding section overhaul
●Grinding roll and journal assembly replacement
●Internal housing and liner repairs
●Classifier inspection and repairs
●Mill coal outlet pipe inspection and repairs.
●Housing liner replacement
●Table segment replacement
●1600 man hours (8 weeks with 5 employees)

4000 hour inspection
●Grinding roll lubrication oil replacement
●Internal inspections and repairs
●120 man hours (3 days with 5 guys)

Gear box, Grinding roll and classifier replacement (Complete overhaul)
●Gear box replacement
●Grinding roll and journal assembly replacement
●Classifier replacement and bearing assembly replacement
●Housing liner replacement
●Table segment replacement
●Mill coal outlet inspection and repairs
●Internal housing repairs
●2400 man hours (12 weeks with 5 employees)

i. See response to subpart (a).

b. Confirmed.

i. See response to subpart (b).

Scott A. Hugo
June 4, 2021

Director – Generation Asset Strategy

Question:

2. Refer to your response to MEC-CE-13(c), including the documents produced with or identified in your initial response and supplemental response. Based on the information provided in this response, there appears to be no internal rate of return ("IRR"), present value ratio ("PVR"), project charter, scope document, or other supporting document for the following major maintenance projects planned for Campbell in 2021 and/or 2022: project nos. 5550, 5617, 5654, 5660, 5661, 5596, 5597, 5669, 9200, 11318, 5549, 5555, 5610, 5618, 5622, 5630, 5659, 10801, 10803, 5494, 5637, 5675, 5686, 5694, 5696, 5715, 5717, 5718, 5740, 9188, 9531, 9646, 10070, 10721, 5516, 5733, 9396, and 9424.

a. Please confirm that these major maintenance projects planned for 2021 and/or 2022 do not currently have supporting documentation.

    i. If not confirmed, please identify and provide any documentation supporting these projects.

b. or those projects that do not have supporting documentation, please confirm that any rationale/support for these projects would be found in either (i) the "Problem Statement" column of the "MM" tab in U20963-MEC-CE-013_ATT_44, or (ii) on pages 124-26 of the Hugo Direct Testimony.

    ii. If not confirmed, please explain why not, and provide the rationale/support for these projects that was omitted from U20963-MEC-CE-013_ATT_44.

Response:

a. The Company has attached concept initiation documents, concept approvals and project charters for the following project ID: 9200, 5610, 10801, 10803, 5718, 9188, 9646, 10721 and 9424. These attachments are labeled as U20963-MEC-CE-984_ATT_1 though ATT_9. The balance of the projects do not have additional supporting documents.

    i. See response to subpart (a).

b. Confirmed.

    i. See response to subpart (b).

Scott A. Hugo
June 4, 2021

Director – Generation Asset Strategy

Question:

3. Refer to your response to MEC-CE-13(c), including the documents produced with or identified in your initial response and supplemental response. Further refer to your response to MEC-CE-645.

a. In response to these requests, the Company has identified IRRs for six capital projects at Campbell that are currently planned for 2021 and/or 2022: project nos. 5462, 9950, 10692, 9526, 10730, and 5707. Has the Company performed an internal rate of return ("IRR") or present value ratio ("PVR") for any other capital project planned for 2021 and/or 2022? If yes:
   i. Please identify all other capital projects planned for 2021 and/or 2022 that have an IRR or PVR, and for each such project:
      1. 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.
      2. Please produce the project charter, project scope document, and/or other written evaluation of the costs and benefits of each identified project.
b. Please confirm that, at present, the Company has not completed an IRR or PVR for the following projects: project nos. 5589, 5692, 5749, and 5750.
   i. If not confirmed for a project(s), please identify the project's 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.

Response:

a. No.
   i. See response to subpart (a).
      1. See response to subpart (a).
      2. See response to subpart (a).
b. Confirmed.
   i. See response to subpart (b).

Scott A. Hugo
June 4, 2021

Director – Generation Asset Strategy

Question:

4. Refer to MEC-CE-13(b)(v), which asked the Company to identify (among other things) any capital and major maintenance expenditures in 2021 that could have been avoided if Campbell Units 1 and/or 2 retire in 2024 or 2025. Further refer to your response, which cites discovery responses 20963-MEC-CE-023 and -024, neither of which identifies any avoidable expenditures at Campbell for the 2021 bridge year.

a. Please confirm that it is the Company's position that all bridge year capital and major maintenance expenditures are unavoidable.

    i. If confirmed, please explain the basis for the Company's position.

    ii. If not confirmed, please reconcile your response with the response to MEC- CE-13(b)(v).

Response:

a. Confirmed. The Company will not receive an order in this case until December 2021. As such, it can not realistically avoid project costs during 2021 as the calendar year will have already passed. However, the Company continually performs condition assessments on generating plant equipment and, to the extent that scheduled projects are unnecessary based upon those assessments, they will be deferred.

    i. See response to subpart (a).

    ii. See response to subpart (a).

Scott A. Hugo
June 4, 2021

Director – Generation Asset Strategy

Question:

5. Refer to your responses to MEC-CE-13(c), including the documents produced with or identified in your initial and supplemental response. The following questions concern the cost estimates for capital and major maintenance projects at Campbell that are identified in U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_45:

a. Project no. 5459 (JHC FH Dust Collector Bag Replacement). According to page 3 of the project charter, U20963-MEC-CE-013_ATT_59, the budget for this project is $85,000, with costs incurred in 2022. The Company's capital expenditure forecast, however, projects a cost of $117,000 in 2021, $72,000 in 2022, $117,000 in 2023, $117,000 in 2024, and $117,000 in 2025. Please explain these discrepancies in the cost and timeline for this project, and provide any updated documentation supporting this project.

b. Project no. 5476 (JHC Site UBAS Capital Replacements). According to page 3 of the project charter, U20963-MEC-CE-013_ATT_61, the budget for this project is $250,000 (with a conceptual budget of $306,365), with costs incurred in 2019. The Company's capital expenditure forecast, however, projects a cost of $173,000 in 2021, $168,000 in 2022, $203,000 in 2023, $193,000 in 2024, and $225,000 in 2025. Please explain these discrepancies in the cost and timeline for this project, and provide any updated documentation supporting this project.

c. Project no. 5473 (JHC 1B Condensate Pump Overhaul). According to page 4 of the project charter, U20963-MEC-CE-013_ATT_60, the budget for this project is $248,000. The Company's capital expenditure forecast, however, projects a cost of $275,000 in 2021. Please explain this discrepancy in the cost for this project, and provide any updated documentation supporting this project.

d. Project no. 9372 (JHC 1A Condensate Pump Overhaul). According to page 3 of the project charter, U20963-MEC-CE-013_ATT_82, the budget for this project is $255,000. The Company's capital expenditure forecast, however, projects a cost of $292,000 in 2022. Please explain this discrepancy in the cost for this project, and provide any updated documentation supporting this project.

e. Project no. 10257 (JHC3 FD fan vibration monitor equipment replacement). According to page 5 of the project charter, U20963-MEC-CE-013_ATT_45, the budget for this project is $116,922, with costs incurred in 2019. The Company's capital expenditure forecast, however, projects a cost of $251,400 in 2021 (and ~$14,000 of costs in 2019 and 2020). Please explain these discrepancies in the cost and timeline for this project, and provide any updated documentation supporting this project.

f. Project no. 11249 (JHC3 Boiler Roof Replacement). According to page 2 of the scope document, U20963-MEC-CE-013_ATT_4, the estimated cost of this project is at $1,680,000. The Company's capital expenditure forecast, however, projects a cost of $2,656,000 in 2021-22. Please explain this discrepancy in the cost for this project, and provide any updated documentation supporting this project.

g. Project no. 5708 (JHC3 Sootblowing Air Compressor Controls). According to page 5 of the project charter, U20963-MEC-CE-013_ATT_69, the budget for this project is $50,000. The Company's capital expenditure forecast, however, projects a cost of $250,000 in 2022. Please explain this discrepancy in the cost for this project, and provide any updated documentation supporting this project.

h. Project no. 5742 (JHC 3 Replace Unit 3 Lake Michigan Intake Screens).

   i. According to page 5 of the project charter, U20963-MEC-CE- 013_ATT_71, the budget for this project is "$651,000 and is based on hard pricing provided to the project sponsor," with costs incurred in 2019. The Company's capital expenditure forecast, however, projects a total cost of $1,845,000, spread over a three-year period ($607,000 in 2021, $619,000 in 2022, and $619,000 in 2023). Please explain these discrepancies in the cost and timeline for this project, and provide any updated documentation supporting this project.

   ii. The Company's capital expenditure forecast in Case U-20697 projected that this project would cost $1,270,000 in 2021, see U-20697, Hugo workpaper WP-SAH-22, line 38, and the Commission did not disallow rate recovery of these costs. Consequently, the 2021 amount identified in U-20697 is greater than the combined 2021-22 costs identified in this case. Please confirm that the Company is not seeking additional rate recovery for this project in this case. If not confirmed, please explain why not.

i. Project no. 5468 (JHC2 Turbine Inspection and Overhaul).

   i. According to page 5 of the project charter, U20963-MEC-CE- 013_ATT_34, the budget for this project is $4,768,000.00, with costs incurred in 2019. The Company's capital expenditure forecast, however, projects a cost of $20,000 in 2020, and $2,651,474 in 2021. Please explain this discrepancy in the project timeline, and confirm that the current estimated cost of this project is $2,671,474. If not confirmed, please explain why not, and provide any updated documentation for this project.

   ii. The Company's capital expenditure forecast in Case U-20697 projected that this project would cost $2,370,000 in 2021, see U-20697, Hugo workpaper WP-SAH-21, line 28, and the Commission did not disallow rate recovery of these costs. Consequently, the 2021 amount identified in U-20697 is only $301,474 more than the combined 2020-21 costs identified in this case. Please confirm that the Company is only seeking $301,474 of additional rate recovery for this project in this case. If not confirmed, please explain why not.

j. Project no. 5469 (JHC2 Turbine Valve Inspection). According to page 5 of the project charter, U20963-MEC-CE-013_ATT_35, the budget for this project is $1,300,000, with costs incurred in 2019. The Company's capital expenditure forecast, however, projects a total cost of $3,601,626 ($1,351,078 in 2020, and $2,250,548 in 2021). Please explain these discrepancies in the cost and timeline for this project, and provide any updated documentation supporting this project.

k. Project no. 5741 (JHC3 Turbine Valve Inspection). According to page 6 of the project charter, U20963-MEC-CE-013_ATT_36, the budget for this project is $1.2 million. The Company's capital expenditure forecast, however, projects a cost of $2,077,125 in 2021. Please explain this discrepancy in the cost for this project, and provide any updated documentation supporting this project.

l. Project no. 5707 (JHC3 Reheater Sootblower). Please explain why there are costs of $1.376 million in 2022 in the project charter (U20963-MEC-CE-013_ATT_12), but $0 in 2022 in the capital expenditure forecast.

    i. If the costs listed in the capital expenditure forecast are incorrect, please provide an updated version of U20963-MEC-CE-013_ATT_44 with corrected capital costs for this project.

    ii. Please also state what amount, if any, the Company is seeking rate recovery for in this case.

m. Project no. 9526 (JHC3 Replace ABB Damper Drives). Please explain why there are costs of $780,700, in 2021 and 2022 combined, in the project charter (U20963- MEC-CE-013_ATT_84) but $669,000 for the same period in the capital expenditure forecast.

    i. If the costs listed in the capital expenditure forecast are incorrect, please provide an updated version of U20963-MEC-CE-013_ATT_44 with corrected capital costs for this project.

    ii. Please also state what amount the Company is seeking rate recovery for in this case.

<u>Response:</u>

It is important to understand the sequence of documentation for projects. The initial document assembled is the concept approval. This document describes the issue, alternatives, desired implementation and the initial budget estimate. It typically is written 6 to 18 months ahead of the initial spend. These are then scheduled into windows of opportunity considering outage timing, resource availability, budget constraints and other factors. In doing so, schedule and cost may be altered. Then, if the project is managed by our project management team, a charter is drafted to ensure alignment between the sponsor and the project manager. This is typically completed just prior to the initial spend, usually 3 months or less. As the project matures the details such as risk, schedules and costs are adjusted. The Company does not go back and adjust each of these documents as it would be time consuming and provide no additional value. Therefore, the discrepancies between the supporting documents are a condition of the project maturation and being detailed out. The funding included within the rate case is the most mature number available and, therefore, was the amount included in the case for cost recovery.

a. The bags are typically replaced annually, see the note at the front of this question for discussion on the difference of cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents. Capital expenditure amounts for future years will be requested at the appropriate time in the appropriate proceeding.

b. The UBAS replacements are an annual item, see the note at the front of this question for discussion on the difference of cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents. Capital expenditure amounts for future years will be requested at the appropriate time in the appropriate proceeding.

c. See the note at the front of this question for discussion on the difference in cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

d. See the note at the front of this question for discussion on the difference in cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

e. See the note at the front of this question for discussion on the difference in cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

f. See the note at the front of this question for discussion on the difference inf cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

g. See the note at the front of this question for discussion on the difference in cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

h. See the note at the front of this question for discussion on the difference in cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents.

    i. The estimate was for the 1st year of the 4 years of scope, replacing ¼ (7) screens each year. The work in 2019 was deferred and the new timing is what is reflected in the current plan.
    ii. The actual and projected amounts for this project for the years 2020 through 2022 will be trued up in this proceeding and, as a result, the maximum total recovery for this project will be limited to those actual and projected values.

i.

    i. See the note at the front of this question for discussion on the difference in cost.
    ii. This **major maintenance project** was completed in 2021 and, as such, will not be considered for establishing electric rates in this proceeding. Generation O&M to be reflected in electric rates will be based upon 2022 O&M projections.

j. See the note at the front of this question for discussion on the difference in cost. This **major maintenance project** was completed in 2021 and, as such, will not be considered for establishing electric rates in this proceeding. Generation O&M to be reflected in electric rates will be based upon 2022 O&M projections.

k. See the note at the front of this question for discussion on the difference in cost. This **major maintenance project** was completed in 2021 and, as such, will not be considered for establishing electric rates in this proceeding. Generation O&M to be reflected in electric rates will be based upon 2022 O&M projections.

l. See the note at the front of this question for discussion on the difference of cost. The Company is requesting recovery of the projected capital expenditure amount included in the case rather than the amount reflected in less mature scope documents. In this case the project began in 2020 and was completed in the 2021 JHCampbell 3 outage and, therefore, there are no projected costs for 2022.

   i. See subpart (l)

   ii. The Company is seeking total recovery of $1,728,743.96 in this case, $378,743.96 representing the actual amount for 2020 and $1,350,000 for 2021.

m. See the note at the front of this question for discussion on the difference in cost. The Company is seeking recovery for the funding included in case at the value included within.

   i. Not applicable

   ii. The company is seeking recovery of $79,000 in 2021 and $590,000 in 2022 in this case.

Scott A. Hugo
June 4, 2021

Director – Generation Asset Strategy

Projected Capital Expenditures at Campbell, 2021-25

Sources *U20963-MEC-CE-013_ATT_44*									*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**		**Disallowed in 2020 Rate Case?**
5539 -JHC1 Replace burners corner 1-8	5539	Campbell 1	$ -	$ -	$ -	$ 100,000	$ 2,700,000	Equipment Condition	N/A			Replace 6 degraded burner assemblies to avoid forced outage due to burner malfunction and possible windbox fire. Maintaining burners in optimized condition is part of the MATS requirements. This is 6 of the 24 burners on the unit.		
9194 -JHC1 PJFF Filter Bag Replacement	9194	Campbell 1	$ 19,000	$ 1,578,000	$ 1,514,100	$ -	$ -	Safety/Compliance/Regulatory	No	U20963-MEC-CE-013_ATT_79; U20963 MEC-CE-013_ATT_2		The Pulse Jet Fabric Filter (PJFF) at JHCampbell Unit 1 removes particulate material from the flue gas stream, prior to the flue gas entering the stack for discharge. The PJFF serves an environmental function, ensuring that JHC 1 remains within the environmental limits that are in place for opacity, which provides a measure of flue gas particulate discharges from the plant. The PJFF also serves the function of increasing the efficiency of both mercury (ACI) and sulfur (DSI) removal technologies used on JHC 1. If the compliance requirements are not met for particulates, mercury or sulfur, the company is subject to legal enforcement and the plant is subjected to derates or forced outages until compliance can be achieved.		
9655 -JHC1 AQCS Projects	9655	Campbell 1	$ 250,000	$ 250,000	$ -	$ 750,000	$ 750,000	Equipment Condition	Yes			JHC1 has air quality control systems (ACI, PJFF) which require periodic equipment replacements and improvements to maintain compliance.		Yes
5538 -JHC 1&2 - 316B Deep Water Intake	5538	Campbell 1&2 Commons	$ -	$ 500,000	$ 7,600,000	$ 29,489,000	$ -	Safety/Compliance/Regulatory	Yes			comply with 316B		Yes
5462 -JHC2 SAH Baskets and Seals	5462	Campbell 2	$ 2,735,000	$ -	$ -	$ -	$ -	Economic & Equipment Condition	N/A	U20963-MEC-CE-013_ATT_8	MEC-CE-008 CONF (U20697-MEC-CE-035_ATT_4 Confidential)	The air preheater baskets and seals are in very poor condition with fouling and heavy erosion. Cold end seals are damaged with an estimated 20% leakage due to damage. Cold end baskets last replaced in 2009 and hot end in 2001. Requires at least a 30 day outage.		Yes
5537 -JHC 2 Replace Burner Assemblies	5537	Campbell 2	$ -	$ -	$ 50,000	$ 550,000	$ 1,325,000	Equipment Condition	N/A			Replace 6 degraded burner assemblies to avoid forced outage due to burner malfunction and possible windbox fire. Maintaining burners in optimized condition is part of the MATS requirements. This is 6 of the 24 burners on the unit.		Yes
5562 -JHC2 Catalyst Management	5562	Campbell 2	$ 175,000	$ -	$ 1,120,000	$ 1,800,000	$ -	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_62; U20963 MEC-CE-013_ATT_17		1. Inspect, record and map current catalyst ash loading and pluggage in JHC2 SCR reactor for each level with catalyst. 2. Obtain required catalyst samples and send out for testing. 3. Clean (vacuum) all four (4) JHC2 SCR reactors levels including up to predetermined points in inlet and outlet ducts. 4. Remove old and install two (2) layers (192 modules) of new (not regenerated) plate type catalyst in JHC2 SCR reactor in Level 3 and Level 4. 5. Remove original and install sixteen (16) new larger sonic horns on Level 3 and Level 4. 6. Conduct SCR tuning followed by SCR warranty testing to ensure new catalyst meets operational requirements as indicated in conformed specification. 7. Additional objectives: a. Provide temporary (less than 3 months) indoor climate controlled storage to protect the new catalyst from adverse weather conditions (in particular, moisture freezing and damaging the pore structure). b. Assess and clean or replace necessary Ammonia Injection Grid (AIG) nozzles and SCR sample probe lines in the SCR inlet and outlet ductwork.		
5566 -JHC 2 PJFF bag replacement	5566	Campbell 2	$ 1,894,000	$ -	$ -	$ -	$ -	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_9		Multiple bag failures could cause the unit to exceed opacity causing unit derate or outage based on the consent decree.		
8615 -JHC2 ID Fan Outlet Duct Replacement	8615	Campbell 2	$ 229,000	$ -	$ -	$ -	$ -	Safety/Compliance/Regulatory	N/A			The Induced Draft (ID) fan outlet duct is located between the ID fan and chimney. Flue gas from the furnace is channeled through this duct at around 300 degrees Fahrenheit at full load and is upstream of the Combustion Emissions Monitoring System (CEMS). The insulation and lagging insulate the hot duct plate from the cool ambient air and prevent corrosion causing condensation on the surface of the duct plate. The insulation and lagging are damaged and missing in several areas. If not repaired the duct plate will fail from corrosion causing flue gas to leak to the outside environment and bypass the CEMS equipment. Flue gas that is emitted will condense on local cool surfaces and form acidic condensation that can corroded nearby surfaces and run into the storm drains posing an environmental hazard.		
9656 -JHC2 AQCS Projects	9656	Campbell 2	$ 250,000	$ 250,000	$ 750,000	$ 750,000	$ 750,000	Equipment Condition	Yes			JHC2 has air quality control systems (SCR, PJFF) which require periodic equipment replacements and improvements to maintain compliance.		Yes
10712 -JHC3 SDA Atomizer 7th Motor	10712	Campbell 3	$ -	$ -	$ 200,000	$ -	$ -	Safety/Compliance/Regulatory	N/A			Each JH Campbell Unit 3 SDA Atomizer use a 6900-volt 1100 HP motor to reduce SO2 emissions. When JHC3 is online, 4 atomizer/motor assemblies operate with one spare assembly per side. The motor OEM, Baldor, recommends major maintenance including bearing replacements every 5-6 years. Funding has been requested to do this work in 2021 and 2022 (see separate project JHC 3 SDA Atomizer Motor Overhauls). This motor maintenance work takes 2 to 4 weeks to complete if planned but could take up to 30 weeks if unplanned and/or if there is catastrophic motor damage. While an existing motor is offsite, JHC3 is at an increased the risk of SO2 non-compliance with continued power generation.		

Sources

U20963-MEC-CE-013_ATT_44								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
5670 -JHC3 SCR Catalyst Management	5670	Campbell 3	$ -	$ 1,959,510	$ 1,866,200	$ 1,959,510	$ 2,000,000	Safety/Compliance/Regulatory	No	U20963-MEC-CE-076_ATT_66		The JHC3 Selective Catalytic Redution (SCR) system requires periodic replacement of catalyst levels as the SCR catalyst deactivates over time. Reactor catalytic potential is deteremined via catalyst lab analysis and the results are input into the Catalyst Management Program to deteremine the strategic timing of the next catalyst replacement based on maintaining a minimum reactor potential required for the completion of the deNOX reaction. The SCR is a must-run system for JHC3 to meet consent decree NOx emission limits. The plant will be derated of forced off line if NOx targets are not met. Failure to meet the 30-day and/or 90-day rolling average NOx limits will results in noncompliance with our Consent Decree and potential fines. JHC3 total SCR potential is predicted to drop below minium (without level replacment) in Jun 2023. The currently scheduled 2023 Spring Periodic Outage was identified as the outage of adequate length to perform the Project.	
5748 -JHC3 Design and Install new Large Particle Ash Screen	5748	Campbell 3	$ -	$ 1,485,100	$ 881,800	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-076_ATT_65		Design and replace the Large Particle Ash screen with an new system that provides better cleaning and more reliability.	
9196 -JHC3 PJFF Filter Bag & Cleaning Air Manifold Replacement	9196	Campbell 3	$ 50,000	$ 3,994,601	$ 3,263,331	$ -	$ -	Safety/Compliance/Regulatory	No	U20963-MEC-CE-013_ATT_3		The Pulse Jet Fabric Filter (PJFF) at JHCampbell Unit 3 removes particulate material from the flue gas stream, prior to the flue gas entering the stack for discharge. The PJFF serves an environmental function, ensuring that JHC 3 remains within the environmental limits that are in place for opacity, which provides a measure of flue gas particulate discharges from the plant. The PJFF also serves the function of increasing the efficiency of both mercury (activated carbon injection) and sulfur (spray dry absorber) removal technologies used on JHC 3. If the compliance requirements are not met for particulates, mercury or sulfur, the company is subject to legal enforcement and the plant is subjected to derates or forced outages until compliance can be achieved. The PJFF clean air piping is required to clean the filter bags and manage pressure drop so that particulate matter can be removed from the flue gas stream. Failure of the cleaning air system would result in a failure to clean the filter bags and the dp across the PJFF will not be controlled. The clean air manifold pipe and arms are expected to corrode as did the Karn 1 PJFF and Karn 2 PJFF cleaning air manifolds.	
9692 -JHC3 AQCS Projects	9692	Campbell 3	$ 250,000	$ 250,000	$ 750,000	$ 750,000	$ 1,000,000	Equipment Condition	Yes			JHC3 has extensive air quality control systems (SDA, SCR, PJFF) which require periodic equipment replacements and improvements to maintain compliance.	Yes
10716 -JHC Ash Field Dozer Replacement	10716	Campbell Site Commons	$ -	$ -	$ -	$ 471,000	$ -	Equipment Condition	N/A			The CAT D6 bulldozer used by Fuel Handling in the JHC Ash Fields will be due for rebuild in 2024-2025.	
5457 -JHC FH Install Air Compressors For Train Airup	5457	Campbell Site Commons	$ -	$ 30,000	$ 486,000	$ -	$ -	Equipment Condition	No			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.	
5459 -JHC FH Dust Collector Bag Replacement	5459	Campbell Site Commons	$ 117,000	$ 72,000	$ 117,000	$ 117,000	$ 117,000	Equipment Condition	No	U20963-MEC-CE-013_ATT_59		Dust Collector filter bags should be replaced every 3-8 years depending on their position and volume of coal dust they collect. Once filter bags become saturated, the suction pressure drops, eventually causing the dust collector to underperform.	
5476 -JHC Site UBAS Capital Replacements	5476	Campbell Site Commons	$ 173,000	$ 168,000	$ 203,000	$ 193,000	$ 225,000	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_61		Aqueous ammonia system includes ammonia storage facility, vaporizer systems for each unit, heat trace, controls, etc. This system would be simpler, more reliable and less maintenance-intensive than the existing system.	
5501 -JHC Site Part 115 B-K landifll cap	5501	Campbell Site Commons	$ -	$ -	$ -	$ -	$ 21,000	Safety/Compliance/Regulatory	N/A			The JHC B-K landfill was operated as an impoundment and was closed when the dry ash landfill began operation. the landfill is capped with a layer of soil and vegetated. While the landfill is considered to be closed, we continue to have groundwater issues.	
5523 -JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.	5523	Campbell Site Commons	$ 1,928,742	$ 15,421,498	$ 5,302,864	$ -	$ -	Safety/Compliance/Regulatory	No	U20963-MEC-CE-013_ATT_6		funding for SEEG rules	Yes
9395 -JHC Dry Ash Landfill Cell Construction & Permitting	9395	Campbell Site Commons	$ 5,482,830	$ -	$ 288,570	$ 5,482,830	$ 2,000,000	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_14		The JH Campbell Dry Ash Landfill will run out of usable airspace in 2022 unless additional airspace in constructed. Additionally, changes to the Michigan Part 115 (solid waste) statute require a Construction Permit Application be submitted prior to construction of future cells.	Yes
9397 -JHC Dry Ash Landfill Closure	9397	Campbell Site Commons	$ 48,000	$ 288,570	$ 1,635,230	$ -	$ 288,570	Safety/Compliance/Regulatory	Yes			Landfills are required to be final closed within 6 months of final waste receipt; thus, interim capping is required when areas of the landfill reach final grades to meet the final overall closure timeline. Additionally, capping reducing landfill infiltration and subsequently leachate management and O&M requirements.	
9528 -JHC Bottom Ash Tanks Chemical Treatment System	9528	Campbell Site Commons	$ 100,000	$ -	$ -	$ -	$ -	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_86; U20963 MEC-CE-013_ATT_20		Current operation of the JH Campbell Bottom Ash Tank System is posing a risk to compliance with NPDES permit requirements at outfall 002A. Since commencement of tank operation, average measured Total Suspended Solids (TSS) levels have increased from ~ 6 mg/L to ~ 20 mg/L, and could potentially still be increasing. Limits at this outfall include a 30 mg/L monthly average for TSS. Further, conversation with Environmental Services has revealed that the decrease noted in water clarity during this same time frame poses a risk to compliance with the Visual Narrative Standard requirement at this outfall.	Yes
11179 -JHC 1A BFP overhaul	11179	Campbell 1	$ -	$ -	$ -	$ 300,000	$ -	Equipment Condition	N/A			JHC Unit 1A Boiler Feedpump will be due for a capital overhaul in 2024.	
5473 -JHC 1B Condensate Pump Overhaul	5473	Campbell 1	$ 275,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_60		The 1B condensate pump has not been overhauled since 2004. The OEM guidelines are to inspect the condensate pumps on 10 year intervals. This will ensure unit reliability.	
5543 -JHC1 Mill Overhaul	5543	Campbell 1	$ 696,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			Coal pulverizers require on-going maintenance to maintain operability.	Yes
5569 -JHC 1 Air Preheater Baskets and Seals	5569	Campbell 1	$ 1,902,000	$ -	$ -	$ -	$ -	Economic & Equipment Condition	N/A	U20963-MEC-CE-013_ATT_7		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.	

Sources *U20963-MEC-CE-013_ATT_44*								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
5587 -JHC 1 Replace air and flue gas expansion joints	5587	Campbell 1	$ -	$ -	$ 238,200	$ 650,500	$ -	Equipment Condition	N/A			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.	
5589 -JHC1 SH Outlet Pendant Tube Panel Replacements	5589	Campbell 1	$ -	$ 20,000	$ 200,000	$ 3,490,000	$ -	Economic & Equipment Condition	N/A	U20963-MEC-CE-013_ATT_65		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	Yes
5612 -JHC 1 DCS and Simulator Replacement	5612	Campbell 1	$ 100,000	$ -	$ -	$ 1,785,200	$ -	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_67		As with all computer network systems, Digital Control Systems (DCS) utilize Operating Systems (OS) systems. The operating system in this case is Windows 10 and Windows Server 2016. The existing Emerson Ovation Operating system is 3.7. The current system was last upgraded in 2019 and the normal expected life cycle is 5 years. Approximately after 5 years, Microsoft stops patch support and Anti-Virus updates. Every major DCS manufactures utilize similar network systems, so replacing the existing system with another provider would require the need to replace all Input and Output cabinets. This would require re-wiring the cabinets, with extensive costs and outage time. This would not resolve the Operating System obsolescence issue. Microsoft has announced end of extended support date of 2026 for Windows 10 and 2026 for Window Server 2016	
5665 -JHC1 Ashpit Replacement	5665	Campbell 1	$ 20,000	$ 432,000	$ 900,000	$ -	$ -	Equipment Condition	N/A			The ash pit condition is deteriorating and a complete re-build is needed to maintain performance.	
9364 -JHC1 HydroJet Controls Replacement	9364	Campbell 1	$ 137,900	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_81		The HydroJet system utilizes 2 water cannons to remove boiler slag off of the center division wall of Unit 1. The canons are controlled from a common cabinet with a local PLC. The controls for the Unit 1 HydroJet system are obsolete and as a result the system has been offline for the last 11 months. The last available spare parts were purchased via EBay in 2017	
9372 -JHC 1A Condensate Pump Overhaul	9372	Campbell 1	$ -	$ 292,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_82		The 1A Condensate Pump is in need of a capital overhaul. It was last overhauled in 2003. The condensate pumps should be overhauled on a 10-year time interval to ensure unit reliability. 1B Condensate Pump has an LTFP request for overhaul as well. 1C Condensate Pump was overhauled in 2016. Unit 1 requires 2 of 3 Condensate Pumps for full load; not having a reliable third pump would put Unit 1 at risk of de-rate. There are two (2) condensate pumps that need to be overhauled.	
9650 -JHC1 Major Motor and Pump Overhauls	9650	Campbell 1	$ 200,000	$ 200,000	$ 300,000	$ 600,000	$ 300,000	Equipment Condition	Yes			Large pumps and motors require overhauls/rewinds on a regular schedule.	Yes
9653 -JHC1 Balance of Plant Equipment	9653	Campbell 1	$ 135,000	$ 135,000	$ 675,000	$ 1,350,000	$ 675,000	Equipment Condition	Yes			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.	Yes
10837 -JHC1&2 Chimney 391' Platform Replacement	10837	Campbell 1&2 Commons	$ 396,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_58		The chimney is a 400 feet reinforced concrete shell structure with an independent, bottom supported, reinforced concrete liner. Flue gas from both units 1&2 breeches the outer shell and liner toward the bottom and is channeled out the top of the liner. There are four full or partial circumference platforms on the chimney. The circumferential platform at the 391-foot elevation is used for access to inspect the shell and liner caps and lightning protection system. This platform is severely corroded from exposure to weather and flue gas over the lifetime of the chimney. It is corroded to the point where it is no longer structurally safe to access.	
5571 -JHC Centac Air Compressor	5571	Campbell 1&2 Commons	$ -	$ -	$ 694,000	$ -	$ -	Equipment Condition	N/A			Per OEM recommendations, these large air compressors should be overhauled on a 7 to 8 year cycle. This compressor was lasr overhauled in 2011.	
11655 -JHC2 Generator Overhaul and Rewedge (Capital)	11655	Campbell 2	$ 1,461,600	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_10		JHC2 Generator is due for an overhaul and has known wedge tightness issues.	
3089 -JHC2 Mill Overhauls (grinding section & gearbox)	3089	Campbell 2	$ 400,000	$ -	$ -	$ -	$ 400,000	Equipment Condition	N/A			Coal pulverizers require on-going maintenance to maintain operability.	Yes
5465 -JHC2 BFP Recirc Flow control valve & iso valves replace	5465	Campbell 2	$ 102,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			The unit 2 MBFP Recirc Flow control valve is seeing erosion in its seating area. This erosion will prevent the seat from sealing to the valve body and over time will erode through the wall of the valve.	
5474 -JHC 2B Condensate Pump Overhaul	5474	Campbell 2	$ 200,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			The 2B condensate pump has had reduced performance levels compared to 2A and 2C condensate pump. This pump has not been overhauled since 2007 and is past its 10 year overhaul frequency.	
5475 -JHC 2 Capital Rebuild Startup Boiler Feedpump Gearbox	5475	Campbell 2	$ 166,600	$ -	$ -	$ -	$ -	Equipment Condition	N/A			Startup boiler feedpump gearbox was inspected fall 2017 during a U2 forced outage. The gear set has some pitting and spalling and the OEM has recommended that the gear set be replaced.	
5545 -JHC2 Overhaul Hydraulic Coupling Rotor	5545	Campbell 2	$ 459,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	Scope included in U20963-MEC-CE-013_ATT_85		Project is to rebuild the spare Hydraulic Coupling rotor removed in 2009 for installation during 2018 periodic outage.	Yes
5573 -JHC 2 Overhaul CCWP & Motors	5573	Campbell 2	$ 580,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_63		JHC Unit 2 CCW pumps and motors are in need of overhaul. The pumps last inspection was May 2018, it was found that the bearings have excessive clearance in them, and the impeller shows wear also. The pump is past the OEM recommended overhaul interval of 10 years, last overhaul was in the Fall of 2000.	Yes
5576 -JHC2 Combustion Air Heat Exchanger Banks	5576	Campbell 2	$ 137,500	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_64		There are six out of 20 combustion air heat exchanger tube banks out of service due to leak. Loss of combustion air heaters requires raising minimum load on cold days to achieve mill hot air temperatures.	

Project	Work ID	Campbell Unit	2021	2022	2023	2024	2025	Approval Criteria	2022 Deferable spending?	Attachment	IRR (if available)	Problem	Disallowed in 2020 Rate Case?
Sources *U20963-MEC-CE-013_ATT_44*								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
5577 -JHC2 - Overhaul JHC2 FD Fan Motors	5577	Campbell 2	$ 402,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			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.	Yes
5591 -JHC2 Secondary Air Duct Insulation Lagging and Expansion Joints	5591	Campbell 2	$ 870,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_66		The insulation and lagging is in poor condition. Recently observed several areas where the lagging on the bottom of the duct inside the plant had come loose and dropped to the floor beneath or was loose and hanging by one edge.	
5594 -JHC2 Main BFP overhaul	5594	Campbell 2	$ 359,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			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.	Yes
5627 -JHC2 Turbine Lube Oil Vacuum Dehydrator	5627	Campbell 2	$ 85,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			The existing lube oil coalescer is antiquated, and in poor condition. The ability to keep the oil supply in the base tank clean and free of water is a struggle.	
5652 -JHC 2 DCS and Simulator Upgrade	5652	Campbell 2	$ -	$ -	$ -	$ 892,600	$ 902,300	Safety/Compliance/Regulatory	N/A	U20963-MEC-CE-013_ATT_18		As with all computer network systems, Digital Control Systems (DCS) utilize Operating Systems (OS) systems. The operating system in this case is Windows 10 and Windows Server 2016. The existing Emerson Ovation Operating system is 3.7. The current system was last upgraded in 2019 and the normal expected life cycle is 5 years. Approximately after 5 years, Microsoft stops patch support and Anti-Virus updates.	
5663 -JHC 2 2A Condensate Pump Overhaul	5663	Campbell 2	$ 210,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			2A Condensate Pump is past its 10 year recommended overhaul frequency.	Yes
9527 -JHC2 Fluid Drive Automatic Oil Level Control	9527	Campbell 2	$ 170,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_85		Oil level in the fluid drive fluctuates for several reasons throughout the day. The existing tank also has a sight glass that very limited in level range. This makes it difficult for operations to maintain level in the tank. If filled to the normal running level the tank will overflow and leak badly. if the lever is lost it can contribute to air bubbles entering the pump which can fail cooler tubes. Due to these issues close oversight of this system by operations is required.	
9651 -JHC2 Major Motor and Pump Overhauls	9651	Campbell 2	$ 200,000	$ 200,000	$ 300,000	$ 300,000	$ 300,000	Equipment Condition	Yes			Large pumps and motors require overhauls/rewinds on a regular schedule.	Yes
9654 -JHC2 Balance of Plant Equipment Replacements	9654	Campbell 2	$ 135,000	$ 135,000	$ 675,000	$ 675,000	$ 675,000	Equipment Condition	Yes			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.	Yes
9950 -JHC2 LP Turbine Blade Replacement	9950	Campbell 2	$ 7,260,000	$ -	$ -	$ -	$ -	Economic & Equipment Condition	N/A	U20963-MEC-CE-013_ATT_11	MEC-CE-008 CONF (U20697-MEC-CE-035 Hugo_ CONF_ATT_5 ; fos2019 - LP Turbine)	During the last inspection, JHC2 LP Turbine components were identified as requiring replacement for continued reliable operation.	
10257 -JHC3 FD fan vibration monitor equipment replacement	10257	Campbell 3	$ 251,400	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_45		The FD fans have five accelerometer vibration probes, two horizontal, two vertical and one axial on each fan. Currently only the horizontal probes are transmitted to DCS. All five probes go to a local junction box for walk-around data collection. With only continuous monitoring of the horizontal probes vibration events that are only detectable or amplified in the vertical and axial planes would go undetected and could become more severe before they show up in the horizontal plane. Early detections of bearing failure can reduce O&M, reduce ROR, and reduce outage duration for repairs. Furthermore, the ability to perform spectral analysis through the DCS will further improve reliability as individual bearing frequencies will be able to be alarmed, trended and monitored. In this way the progression of bearing failure through trending can help predict shut down criteria.	
10258 -JHC3 Primary air fan motor vibration monitoring	10258	Campbell 3	$ 120,030	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_46		The existing Bently Nevada 3300 rack is outdated and no longer supported. There is no axial vibration indication on the fan bearings. This project will upgrade the vibration monitoring equipment to a current version.	
10697 -JHC3 PAH Expansion Joint Replacement	10697	Campbell 3	$ -	$ 70,000	$ 190,000	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_49		The Primary Air Heaters (PAH) are a regenerative style air heater with heating elements that absorb waste heat from the flue gas, then transfer this heat to the incoming cold air by means of continuously rotating heat transfer elements of specially formed metal plates. Thousands of these high efficiency elements are spaced and compactly arranged within 32 sector-shaped compartments of a radially divided cylindrical shell, called the rotor. Expansion joints take up thermal growth between the PAH and the air and flue gas ducts while providing a leak proof seal. The expansion joints on the flue gas inlet duct have failed due to erosion from ash and breakdown of materials from continuous exposure to high temperatures and have been temporarily repaired. Expansion joint leaks on the flue gas side cause ambient air from the boiler room to be drawn into the flue gas duct reducing the flue gas temperature and heat transfer to the combustion air. The compounding effect is that the boiler must fire harder to increase flue gas temperature which increases coal flow, air flow and steam temperature, and thereby increasing heat rate.	
10709 -JHC3 Chimney Liner Expansion Joint Replacement	10709	Campbell 3	$ 24,500	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_50		The chimney is a reinforced concrete shell structure with an independent steel liner. Flue gas from unit 3 breeches the outer shell and liner near the bottom and is channeled upward through the liner to the atmosphere. The liner is supported near the top of the chimney with an expansion joint near the bottom to allow for thermal expansion. The expansion joint is in poor condition and has at least two holes in it. Holes allow cold air to enter the liner which can cause localized condensation of flue gas contributing to corrosion of the steel liner.	

Sources													
U20963-MEC-CE-013_ATT_44								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
10713 -JHC3 DCS and Simulator Replacement	10713	Campbell 3	$ -	$ -	$ 1,044,000	$ 1,066,000	$ -	Safety/Compliance/Regulatory	N/A			As with all computer network systems, Digital Control Systems (DCS) utilize Operating Systems (OS) systems. The operating system in this case is Windows 10 and Windows Server 2016. The existing Emerson Ovation Operating system is 3.7. The current system was last upgraded in 2019 and the normal expected life cycle is 5 years. Approximately after 5 years, Microsoft stops patch support and Anti-Virus updates. Every major DCS manufacturer utilizes similar network systems, so replacing the existing system with another provider would require the need to replace all Input and Output cabinets. This would require re-wiring the cabinets, with extensive costs and outage time. This would not resolve the Operating System obsolescence issue. Microsoft has announced end of extended support date of 2026 for Windows 10 and 2026 for Window Server 2016	
10714 -JHC FH 24B Gearbox Emergency Spare	10714	Campbell 3	$ 102,400	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_51		At the JHC site in the Fuel Handling department, 24B conveyor gearbox is original to the build of the Transfer House and currently doesn't have a spare on site. If the 24B gearbox were to fail, there would not be a spare to replace and the lead time to build a spare would be approximately 16-18 weeks. This would limit the use of the "B" fueling path to just the Unit 3 Dumper to fuel the plants and the Emergency Reclaim would no longer be available until a spare gearbox could be built and acquired. This emergency spare is vital to the continued reliability of the "B" fueling path at the JHC site.	
10798 -JHC3 Windbox Seal and Front Waterwall Tubes	10798	Campbell 3	$ 225,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_55		Many tubes in the Front Wall of the JHC3 Boiler are pulled away from the Windbox casing and there are through holes into the casing. The torn casing allows outside air to enter the furnace and cause problems with combustion tuning efforts.	
10799 -JHC3 Replace Burner Flame Sensor Controllers	10799	Campbell 3	$ 537,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_56		Currently, the JHC3 Flame Sensors have been adjusted so they will not trip the mills. While this allows us to operate, it also means that they do not properly see when there is trouble. This is done with gain controls via "Blue Box".	
10800 -JHC3 8-2 Line Switch	10800	Campbell 3	$ -	$ 330,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_57		During the JHC 2019 Fall outage, the 8-2 line switch was operated and upon closure, did not close and latch properly resulting in the subsequent wind blowing the contacts open causing periodic arcing until HVD was able to support with manually closing the switch with the aid of a bucket truck. To prevent further issues during the outage, jumpers were placed across the switch rendering the switch out of service. Through the investigation, it was noted that the switch that was installed is no longer used by HVD due to issues they have experienced. The switch on the 8-1 transformer will be replaced in 2020, when it was closed during the outage, it caused the transformer to single phase for long enough that the relaying tripped the 899 which caused the plant to go on purely backup power. The switch is presenting as very unreliable.	
10823 -JHC3 House Service Air Compressor Replacement	10823	Campbell 3	$ 1,423,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_13		The House Service air system supplies air to the plant for essential operation such as ignitors, ignitor and burner purge, aspirating or sealing air, and for emergency auxiliary air motors. The system supplies nonessential air for plant operation and maintenance by means of quick disconnect hose connections for air operated hand tools or other temporary equipment. The House Service Air is the primary source of air to the instrument air system and the house service air with instrument air compressor are used as a backup for instrument air system. The system also supplies air to the coal handling system along the conveyor galleries The House Service Air system consists of one (1) 100 percent capacity centrifugal type compressor which discharges air through an after cooler/cyclone moisture separator to two receiver tanks (storage tanks). The House Service Air Compressor is equipped with an Auxiliary Lube Oil pump, which supplies oil for lubrication during start-ups and shutdowns. The current house service air compressor has outdated controls and in need of an overhaul. It is significantly undersized. Currently during unit outages operations leaves one of the big soot blowing air compressors running to supply house service air to the plant. During operation the instrument and house service air system uses 2,000 to 4,000 SCFM from the soot blowing air compressor which reduces its capacity to sootblowers.	
11249 -JHC3 Boiler Roof Replacement	11249	Campbell 3	$ 50,000	$ 2,606,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_4		Early in 2020, a wind storm tore off a portion of the JHC3 Boiler Building Roof. This section was repaired, but an assessment revealed the roof has deteriorated and is beyond its expected life.	
5673 -JHC3 HP Turbine Drain Piping Replacements	5673	Campbell 3	$ -	$ 10,000	$ 653,000	$ 2,535,000	$ 277,000	Equipment Condition	Yes			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	Campbell 3	$ -	$ -	$ 75,000	$ 750,000	$ -	Economic	No Spending in 2022			During shutdowns, condensate forms in the low points of the reheater tubing (typically the inverted loop and sagging horizontal tubing) where moisture is unable to drain.	
5691 -JHC3 Replace O2 monitors	5691	Campbell 3	$ 944,600	$ 904,600	$ -	$ -	$ -	Safety/Compliance/Regulatory	Yes			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.	Yes
5692 -JHC3 SH Terminal Tube Replacement PT-01685	5692	Campbell 3	$ -	$ 40,000	$ 50,000	$ 6,500,000	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_68		Replace sections of tubing from furnace up into outlet header. Based on tube sample analysis and oxide scale thickness measurements to be performed in 2016.	
5693 -JHC3 Mill Complete Overhauls	5693	Campbell 3	$ 1,335,000	$ 1,264,800	$ 1,295,300	$ 643,000	$ -	Equipment Condition	Yes			Coal pulverizers require on-going maintenance to maintain operability.	Yes

Sources													
U20963-MEC-CE-013_ATT_44								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
5702 -JHC 3 Replace 480V cables to MCC 33C2	5702	Campbell 3	$ 260,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			The incoming cables to MCC33C2 were found to be degraded during the 2018 outage. They should be replaced prior to failure. X phase meggered at 25 MOhms.	
5707 -JHC3 Reheater Sootblower	5707	Campbell 3	$ 1,350,000	$ -	$ -	$ -	$ -	Economic	N/A	U20963-MEC-CE-013_ATT_12	U20963-MEC-CE-645-CONF_ATT_1 ; U20963-MEC-CE-645-CONF_ATT_2	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.	Yes
5708 -JHC3 Sootblowing Air Compressor Controls	5708	Campbell 3	$ -	$ 250,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_69		High furnace exit gas temp (FEGT) and economizer exit gas temps (EEGT) lead to derates from high SCR inlet temperatures. High FEGT also leads to ash plugging in the economizer which has caused forced outages and extensive repairs.	Yes
5735 -JHC 3 Replace U3 Diesel Generator Controls	5735	Campbell 3	$ 428,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_70		The controls for the U3 emergency diesel generator are degraded and at end of life. The diesel generator will often not sync and load on the first attempt. The generator breakers are federal pacific which are unreliable.	
5742 -JHC 3 Replace Unit 3 Lake Michigan Intake Screens	5742	Campbell 3	$ 607,000	$ 619,000	$ 619,000	$ -	$ -	Safety/Complianc e/Regulatory	Yes	U20963-MEC-CE-013_ATT_71		The JH Campbell Intake Screens, Lake Michigan intake structures, are seeing degradation and corrosion due to their age. They were installed around 1978/79. The intake screens that have baskets that are degrading to the point collapse of the screens.	
5749 -JHC3 Replace Boiler Sidewall Panels	5749	Campbell 3	$ 10,000	$ 25,000	$ 318,600	$ 2,604,000	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_72		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	Campbell 3	$ 10,000	$ 25,000	$ 559,700	$ 1,899,100	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_73		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 Baskets and Seals	5751	Campbell 3	$ -	$ 47,000	$ 2,425,500	$ 1,484,800	$ -	Economic & Equipment Condition	Yes	U20963-MEC-CE-013_ATT_74		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.	
5752 -JHC3 Static Excitation System Controls Replacement	5752	Campbell 3	$ -	$ -	$ -	$ 450,000	$ -	Equipment Condition	N/A			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. In order to maintain reliability of the unit and reduce p	
5753 -JHC3 8A HPH Replacement	5753	Campbell 3	$ 100,000	$ 650,000	$ 4,739,800	$ 200,000	$ -	Economic	Yes			8A HPH has experienced multiple heater tube leaks in the de-superheating section that have caused 43 MW de-rates to the unit and heat rate penalties due to bypassing the 'B' HPH string. These heaters are from original design 1980.	
8637 -JHC3 Boiler Power Electromatic Relief Valve Replacement	8637	Campbell 3	$ 149,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_77		JHC3 Electromatic Relief Valve leaking, valved out in 2017.	
9131 -JHC3 BFP A Pump Overhaul	9131	Campbell 3	$ -	$ -	$ -	$ 839,790	$ -	Equipment Condition	N/A			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.	
9143 -JHC3 H2 Dryer Replacement	9143	Campbell 3	$ 83,310	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_78		The current gas dryer on the JHC3 Generator is a (BAC-50 Lectrodryer) dual tower dehydrator. Unfortunately this gas dryer is obsolete. Parts cannot be obtained for this skid. If the skid breaks, repair could be difficult or impossible resulting in forced outages or generator damage due to hydrogen moisture. A new skid will help to ensure the reliability of this system and of the insulation system of the generator.	
9525 -JHC3 EHC Fluid Purification System Replacement	9525	Campbell 3	$ 81,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A	U20963-MEC-CE-013_ATT_83		The current Campbell 3 EHC purification system is old antiquated technology. At times we struggle to maintain our EHC fluid within the GE recommended parameters.	
9526 -JHC3 Replace ABB Damper Drives	9526	Campbell 3	$ 79,000	$ 590,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_84	U20963-MEC-CE-013_ATT_40 Confidential; U20963-MEC-CE-013_ATT_41 Confidential	Dampers control combustion air and flue gas flow. The damper drive receives a signal from the DCS to open and close the damper or modulate based on a temperature or air flow requirement. This project pertains to six damper drives manufactured by ABB which are either obsolete and ABB does not offer a replacement unit, are costly to repair, or replacement parts are not offered. These drives are on the primary air fan outlet dampers, primary air heater gas inlet dampers and the Over Fire Air (OFA) dampers. There have been multiple issues with these dampers causing unit startup delays, derates, and air control issues. The four OFA dampers control the amount of air to the furnace to complete combustion of fuel in the second stage, which was part of the Low NOx boiler modification. If control of the OFA is hindered, then the optimal air staging and combustion is compromised causing increased NOx formation. All the OFA damper drives leak oil requiring drip pans and funnels to collect leaking oil which is a potential safety fire hazard. The two A-side OFA damper drives were replaced because they continually rejected to manual several times a day requiring the operator to clear the alarm, allow the damper position to settle out and re-automate. This is a nuisance to the operators especially when there are emergent tasks to be performed and a good reason why the B-side OFA dampers should be replaced. One of the Primary Air Fan outlet dampers had a limit switch fail causing the inlet damper on the fan to close which nearly tripped the unit but caused a derate for several hours.	

Sources														
U20963-MEC-CE-013_ATT_44								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
9529 -JHC3 GSU Replacement	9529	Campbell 3	$ -	$ -	$ 46,655	$ 933,100	$ 5,685,045	Equipment Condition	N/A			The GSUs (Generator Step-Up transformers) at JHC 3 are nearing the end of life. There are some indicating gases that we are monitoring indicative of a transformer near the end of life. From a report issued in 2016 by Doble after an internal inspection and subsequent conversations the transformer life was estimated at 5-7 years	
9530 -JHC 3A SBAC Overhaul	9530	Campbell 3	$ -	$ -	$ -	$ 905,107	$ -	Equipment Condition	N/A			Complete capitol air compressor overhaul	
9671 -JHC Fuel Handling/Infrastructure Replacements	9671	Campbell 3	$ 500,000	$ 750,000	$ 1,500,000	$ 1,500,000	$ 500,000	Equipment Condition	Yes			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.	Yes
9689 -JHC3 Major Motor and Pump Overhauls	9689	Campbell 3	$ -	$ 400,000	$ 400,000	$ 500,000	$ 500,000	Equipment Condition	Yes			Large pumps and motors require overhauls/rewinds on a regular schedule.	
9690 -JHC3 Balance of Plant Equipment Replacements	9690	Campbell 3	$ 180,000	$ 180,000	$ 675,000	$ 675,000	$ 675,000	Equipment Condition	Yes			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.	Yes
10717 -JHC Ash Field Compactor Replacement	10717	Campbell Ash Handling	$ -	$ -	$ -	$ 192,000	$ -	Equipment Condition	N/A			The CAT CS56B Compactor used by Fuel Handling in the JHC Ash Fields will be due for rebuild in 2024-2025.	
10692 -JHC3 Dumper Sump Pumps	10692	Campbell Fuel Handling	$ 63,000	$ -	$ -	$ -	$ -	Economic	N/A	U20963-MEC-CE-013_ATT_47	U20963-MEC-CE-013_ATT_38 Confidential; U20963-MEC-CE-013_ATT_39 Confidential	JH Campbell Fuel Handling has 2 sump pumps, located in the basement of the Unit 3 Dumper that is in need of upgrade. These sump pumps help keep water and coal/solids from building up the Unit 3 Dumper basement, protecting the Tail Pulley for 10B Dumper conveyor. Unit 1&2 Dumper and the 1&2 Reclaim basement had the Vaughn style "Chopper" Pumps installed in 2010 as a trial to test the reliability of the pumps. Since their installation, they have never been out of service for repair, other than routine maintenance and MP's. The Unit 3 Dumper, Transfer House and Emergency Reclaim sump pumps, in comparison, are out of service periodically throughout the year for issues with the impeller being jammed and/or plugged with large chunks of coal. The Vaughn "Chopper" pumps have double shrouded impeller that allow chunks of coal and solids to be ground and passed through at 1.625". Adding these sump pumps will increase reliability, since this is the main area for unloading coal at JH Campbell. This will help Fuel Handling maintain MIOSHA housekeeping standards for combustible dust. Routine cleaning is conducted at the Unit 3 Dumper once per day and major cleaning once per week. This basement has flooded many times in the past and the 10B Tail Pulley bearings were submerged, which causes that conveyor to be out of service at minimum 1-4 days, either for bearing inspection or bearing replacement.	
10693 -JHC3 Transfer House Sump Pumps	10693	Campbell Fuel Handling	$ -	$ -	$ 63,000	$ -	$ -	Economic	N/A			JH Campbell Fuel Handling has 2 sump pumps, located in the basement of the Transfer House that are in need of upgrade. These sump pumps help keep water and coal/solids from building up in the Transfer House basement, protecting the Tail Pulley for 26B Transfer conveyor. Unit 1&2 Dumper and the 1&2 Reclaim basement had the Vaughn style "Chopper" Pumps installed in 2010 as a trial to test the reliability of the pumps. Since their installation, they have never been out of service for repair, other than routine maintenance and MP's. The Unit 3 Dumper, Transfer House and Emergency Reclaim sump pumps, in comparison, are out of service periodically throughout the year for issues with the impeller being jammed and/or plugged with large chunks of coal. The Vaughn "Chopper" pumps have double shrouded impeller that allow chunks of coal and solids to be ground and passed through at 1.625". Adding these sump pumps will increase reliability, since this is a section of the main fueling path for the plants at JH Campbell. This will help Fuel Handling maintain MIOSHA housekeeping standards for combustible dust. 26B conveyor cleaning is conducted once per week, at minimum and all spoils go directly to the sump pump area. This basement has flooded a few times in the past and the 26B Tail Pulley bearings were submerged, which causes that conveyor to be out of service at minimum 1-4 days, either for bearing inspection or bearing replacement.	
10695 -JHC3 Emergency Reclaim Sump Pumps	10695	Campbell Fuel Handling	$ -	$ 63,000	$ -	$ -	$ -	Economic	Yes	U20963-MEC-CE-013_ATT_48		JH Campbell Fuel Handling has 2 sump pumps, located in the basement of the Emergency Reclaim that are in need of upgrade. These sump pumps keep water and coal/solids from building up in the Emergency Reclaim basement, helping protect the Tail Pulley for 24B conveyor. Unit 1&2 Dumper and the 1&2 Reclaim basement had the Vaughn style "Chopper" Pumps installed in 2010 as a trial to test the reliability of the pumps. Since their installation, they have never been out of service for repair, other than routine maintenance and MP's. The Emergency Reclaim sump pumps, in comparison, are out of service periodically throughout the year for issues with the impeller being jammed and/or plugged with large chunks of coal. The Vaughn "Chopper" pumps have double shrouded impeller that allow chunks of coal and solids to be ground and passed through at 1.625". Adding these sump pumps will increase reliability, since this is a section of the main fueling path for the plants at JH Campbell. This will help Fuel Handling maintain MIOSHA housekeeping standards for combustible dust. 24B conveyor cleaning is conducted once per week, at minimum and all spoils go directly to the sump pump area. This basement has flooded many times in the past and the 24B Tail Pulley bearings were submerged, which causes that conveyor to be out of service at minimum 1-4 days, either for bearing inspection or bearing replacement.	N/A
10715 -Coal Fleet Fuel Handling Dozer Rebuilds	10715	Campbell Fuel Handling	$ 1,116,000	$ 1,130,000	$ 587,000	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_5		The bulldozers used by Fuel Handling to support JHC1-3 and DEK1&2 operation require periodic rebuilds based on operating hours.	

Sources

U20963-MEC-CE-013_ATT_44								*U20963-MEC-CE-637_ATT_1*	*U20963-MEC-CE-648-ATT_1*	*013_ATT_1; Supplemental List of Scope Documents; U20963-ST-CE-*		*U20963-MEC-CE-013_ATT_44*	
Project	**Work ID**	**Campbell Unit**	**2021**	**2022**	**2023**	**2024**	**2025**	**Approval Criteria**	**2022 Deferable spending?**	**Attachment**	**IRR (if available)**	**Problem**	**Disallowed in 2020 Rate Case?**
10718 -JHC Fuel Handling DCS Replacement	10718	Campbell Site Commons	$ -	$ -	$ 334,000	$ 437,000	$ -	Safety/Compliance/Regulatory	N/A			As with all computer network systems, Digital Control Systems (DCS) utilize Operating Systems (OS) systems. The operating system in this case is Windows 10 and Windows Server 2016. The existing Emerson Ovation Operating system is 3.7. The current system was last upgraded in 2019 and the normal expected life cycle is 5 years. Approximately after 5 years, Microsoft stops patch support and Anti-Virus updates. Every major DCS manufactures utilize similar network systems, so replacing the existing system with another provider would require the need to replace all Input and Output cabinets. This would require re-wiring the cabinets, with extensive costs and outage time. This would not resolve the Operating System obsolescence issue. Microsoft has announced end of extended support date of 2026 for Windows 10 and 2026 for Window Server 2016 Existing Fiber runs don't have spare fibers, so a fiber failure could result in FH DCS failure. The existing multiple patch panels connection points increase risk of failure. Running new full run fiber cables will assure enough redundant fibers, and lower connection failure risks. This would support end of life for site and FH Admin Bldg to U3 would be independent of running through U1 & U2 building.	
10719 -JHC N & S Pigeon Lake Jetties - Concrete & Fence Replacement	10719	Campbell Site Commons	$ 192,000	$ 740,000	$ -	$ -	$ -	Safety/Compliance/Regulatory	No	U20963-MEC-CE-013_ATT_52		The north and south jetties, as well as the paved path just east of the north jetty have suffered significant damage as a result of the high water on Lake Michigan. The south jetty has further eroded dunes threatening our access to the jetty, as well as concrete that is starting to break apart and wash out on the jetty. The north jetty has extensive concrete damaged along its west end due to sand wash out, the chain link fence has been destroyed, and the asphalt path from that connects the jetty to the boardwalk has been washed away. We need safe access to the north and south jetties to install lights and conduct other periodic maintenance; we are required to provide safe access to the north jetty for recreational opportunities in accordance with our LPS FERC license.	
10730 -JHC Ash Silo Secondary Electrical Source	10730	Campbell Site Commons	$ 30,000	$ 601,000	$ -	$ -	$ -	Equipment Condition	Yes	U20963-MEC-CE-013_ATT_53	CE-013_ATT_42 Confidential; U20963-MEC-CE-	Load Center 88M provides power to the ash silos that are used by all the units at the Campbell site. In the past month, the Load Center has tripped offline twice due to a fault caused by water intrusion. This has drawn attention to the lack of redundancy in the Ash Silo Electrical System, which has the potential to cause site-wide derates and forced outages.	
5480 -JHC FH Replace Fuel Handling Conveyor Belts	5480	Campbell Site Commons	$ 427,000	$ -	$ -	$ -	$ -	Equipment Condition	N/A			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.	Yes
5481 -JHC Small Valves and Instrumentation	5481	Campbell Site Commons	$ 375,000	$ 430,000	$ 435,000	$ 440,000	$ 445,000	Equipment Condition	No			A number of small valves and instrumentation fail annually requiring replacement.	
5482 -JHC Small Tools and Equipment	5482	Campbell Site Commons	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	Equipment Condition	No			Site requires capital funds to purchase necessary tools and equipment in order to perform necessary maintenance and repairs.	
5530 -JHC Site Potable Water Wells 4 and 6	5530	Campbell Site Commons	$ -	$ 115,800	$ -	$ 122,900	$ -	Equipment Condition	No			Potable water wells and associated pumps should be maintained on a 5-10 year interval.	
8250 -JHC Small Pumps and Motors	8250	Campbell Site Commons	$ 375,000	$ 430,000	$ 435,000	$ 440,000	$ 445,000	Equipment Condition	No			A number of small pumps and motors fail annually requiring replacement.	

Question:

15. Refer to page 52, lines 18-21 of the Hugo Direct Testimony. With regards to the Campbell Unit 2 SAH Basket and Seal Replacement (project no. 5462), please produce all documents supporting the Company's contention that "the current condition of this equipment now necessitates that this project move forward in 2021."

Response:

The following is our System Planners assessment of the current condition: The cold end radial seals are in very poor condition. Erosion from sootblower and fly ash has caused the seals to degrade to a point where large sections are missing, bent and worn, and are about 50% efficient or less. This causes greater air leakage from the combustion air duct to the flue gas duct, thus increasing load on the Forced Draft (FD) and Induced Draft (ID) fans. This resulted in JHCampbell 2 being fan-limited during its Generation Verification Test Capacity (GVTC) testing and contributed to the unit's inability to achieve 360MW. The cold end baskets have significant erosion and plugging; the erosion is from sootblowers and fly ash. This causes less heating surface area thereby resulting in decreasing heat transfer and reducing efficiency. The erosion also causes the baskets to shift twice per revolution which increases fatigue stress on the rotor structural components causing fatigue failures; in 2018 there was a failure of a pin rack segment from fatigue. Plugging of the baskets creates high differential pressure (dp) and unbalance of the rotor. High differential pressure once again requires the ID and FD fans to run at greater load to overcome it. Unbalance of the rotor increases fatigue on structural components and increased vibration in the drive components. Furthermore, historically these horizontal shaft rotors have a greater risk of rotor post failure from fatigue due to the design. This is a high risk which increases with high dp and rotor unbalance.

Scott A. Hugo
April 13, 2021

Director – Generation Asset Strategy

Question:

5. Refer to MEC-CE-22, which requested any documents supporting the Company's contention that "the current condition of this equipment now necessitates that [the Campbell 2 SAH Basket and Seal Replacement] project move forward in 2021," and to your response.

a. Please confirm that any support for the Company's contention was provided in your narrative response to MEC-CE-22.
    i. If not confirmed, please produce any documents supporting the Company's contention.
b. Was this System Planner's assessment written up in response to this discovery question? If not, when was this assessment drafted?

Response:

a. Confirmed.
    i. See subpart (a).
b. This written response was drafted for the discovery request. The assessment and recommendation to perform the work was a result of inspections and testing performed in 2020.

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

Question:

7. The following questions concern project no. 5462, the Campbell Unit 2 SAH Basket and Seal Replacement project.
a. Please confirm that the estimated cost of this project has increased by $310,000 (for a total of $2.735 million) over the past year.
i. If not confirmed, please reconcile your response with U20697-MEC-CE-1014-Hugo_ATT_1, which projects a $2,425,000 expenditure in 2021 for project no. 5462 (cell F4).
b. Please confirm that the most recent IRR analysis for this project is presented in U20697-MEC-CE-035-Hugo_CONF_ATT_4 (produced in response to MEC-CE-8).
i. If not confirmed, please produce a copy of any IRR, PVR, or any other economic analysis of project 5462. Please produce any such analysis in machine-readable electronic format, with formulas intact, including any supporting workpapers and modeling files.
c. Please confirm that the project charter for this project was produced as U20963-MEC-CE-013_ATT_8. If not confirmed, please identify the project charter for no. 5462.
d. Refer to your response to MEC-CE-13(c)(i). Please confirm that the Company has produced all project charters, scope documents, economic analyses, or other evaluations for project no. 5462.
i. If not confirmed, please supplement your response to MEC-CE-13(c)(i) with the requested documents.

Response:

a. Confirmed.
    i. See subpart (a).
b. Confirmed.
    i. See subpart (b).
c. Confirmed.
d. Confirmed. The most up to date versions of the documents requested have been provided.
    i. See subpart (d).

Scott A. Hugo
May 13, 2021

Director – Generation Asset Strategy

MEC-60C

CONFIDENTIAL EXHIBIT

January 11, 2021 Electronically Submitted via MiWaters

Michigan Department of Environment, Great Lakes, and Energy
Water Resources Division
Permit Section
Attn: Christine Aiello
Constitution Hall
5th Floor South, Constitution Hall
Lansing, MI 48933

RE: CONSUMERS ENERGY COMPANY, J.H. CAMPBELL COMPLEX NPDES PERMIT NO. MI0001422 PERMIT MODIFICATION, STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES

Dear Ms. Aiello,

Consumers Energy Company (Consumers) requests a modification of the J.H. Campbell (Campbell) NPDES Permit No. MI0001422 to Part I Section A(13) regarding the Steam Electric Effluent Limitation Guidelines (ELG) compliance date. Per our November 23, 2020 meeting and 40 CFR 122.62(a)(3)(i), Consumers is submitting the following information to support this request. Consumers requests this modification as a result of United States Environmental Protection Agency's (EPA) ELG 2020 Reconsideration Rule (85 FR 64650) published on October 13, 2020.

According to the 2020 Reconsideration Rule, in 40 CFR 423.13(k)(1)(i), dischargers must meet the discharge limitation by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025. Campbell's ELG compliance deadline under Part I, Section A(13) of its NPDES permit is currently December 31, 2023. Consumers requests that EGLE modify the compliance date to December 31, 2025. This additional time will provide for a more robust and cost-effective system and ensure continued reliable operation of the Campbell plant, including allowing for adequate planning and preparation of the rule; sufficient time for data collection, engineering, design, and competitive procurement; and adequate time for construction and commissioning to ensure full compliance with the revised ELG technology basis.

Background and Legal Standard for Modification Request

Per the following language, Consumers' ELG compliance date under Part I, Section A(13) of Campbell's NPDES permit is currently December 31, 2023:

13. Schedule for Final Effluent Limitations for Bottom Ash Transport Water

On September 30, 2015, the USEPA finalized a rule revising the effluent limitation guidelines (ELGs) for the steam electric power generating point source category (40 CFR 423). This rule specifies compliance dates for meeting the final effluent limitations for bottom ash transport water. On September 18, 2017, USEPA published the final rule "Postponement of Certain Compliance Dates for the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category," effective on the date of publication, postponing the compliance dates for the best available technology economically achievable (BAT) regulations until USEPA completes its next rulemaking concerning bottom ash transport water.

As a condition of this permit, the permittee shall achieve compliance with any final effluent limitations for bottom ash transport water consistent with the compliance dates stipulated in the final ELGs in 40 CFR 423 following reconsideration of the rule. In accordance with the current requirements of the rule, the Department is setting a compliance date of December 31, 2023; beginning on this date, the permittee is prohibited from discharging newly generated bottom ash transport water from the facility through any outfall. Following the reconsideration of the rule, the Department will revise the compliance schedule, as necessary, consistent with the revised effluent limitation guidelines, taking into consideration the applicable design, procurement, and construction schedules.

This permit condition allows for EGLE to revise the compliance schedule, as necessary, consistent with the revised effluent limitation guidelines, taking into consideration the applicable design, procurement, and construction schedules. This is in line with 40 CFR 423.11(t), which defines the phrase "as soon as possible" to meet the discharge limitations. However, the 2020 Reconsideration Rule changed the "as soon as possible" date under 40 CFR 423.13(k)(1)(i) to October 13, 2021 with a no later than date of December 31, 2025.

According to §423.11(t) the permitting authority can establish a later date after receiving site-relevant information from the discharger based on the following factors:

(1) Time to expeditiously plan (including to raise capital), design, procure, and install equipment to comply with the requirements of the final rule;

(2) Changes being made or planned at the plant in response to greenhouse gas regulations for new or existing fossil fuel-fired power plants under the Clean Air Act, as well as regulations for the disposal of coal combustion residuals under subtitle D of the Resource Conservation and Recovery Act;

(3) For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment; and

(4) Other factors as appropriate.

EPA determined that extending the "no later than" date for compliance with the Bottom Ash (BA) transport water requirements to December 31, 2025 allows companies time to analyze the final rule, plan, and construct any necessary treatment system upgrades under COVID-19 construction protocols[1]. As such, Consumers is requesting a permit modification to extend the compliance deadline to December 31, 2025, based on the following justifications under factor numbers 1 and 4.

ELG Project Timeline

Included in Attachment A is Consumers timeline for project completion under the 2020 Reconsideration Rule and below is justification under §423.11(t)(1).

§423.11(t) Factor 1: Expeditiously plan

Since as early as 2012, Consumers has taken steps to fully understand our overall waste streams and segregate them as appropriate; however, when a federal rule that has a major impact on our operations is postponed, we found it prudent for the company and our rate payers to wait for the Reconsideration Rule to be finalized to ensure we understood all the requirements of the rule. This ensures we design a system meeting the regulatory compliance requirements set forth in the revised rule, and not the prior 2015 rule.

In November 2019, EPA issued the proposed ELG reconsideration rulemaking (84 FR 64620). Consumers reviewed and analyzed the proposed rule, which required a high recycle rate system as Best Available Technology (BAT) with a potential allowance for blowdown of BA purge water. This was a change from the 2015 zero liquid discharge requirement. With a better understanding of what the potential final rulemaking may entail, Consumers has been taking active steps and instituted a sampling program to better understand constituents within BA transport water and the implications of recycling this waste stream. Consumers found it prudent to initiate sampling prior to the final rulemaking, starting procurement for outside support in February of 2020. Sampling was initiated in June 2020, with only a slight delay due to COVID-19 impacts and the need to organize sampling events in a safe manner. The final rulemaking (85 FR 64650) was published on October 13, 2020 and was effective December 14, 2020. Overall changes between the proposed rulemaking and final rule were minimal and still require a high recycle rate system as BAT with up to 10 percent allowance for blowdown of BA purge water.

This study will ensure a better understanding of water chemistry and implications to system equipment once the existing BA tank system is converted to a high recycle rate system. While

[1] Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Part 2 Section 19

confirmatory sampling will continue through December 2021, the study will provide additional concepts for a high rate recycle system by June 2021. By conducting sampling over a year, greater insight into seasonal and fuel source variability and its impacts on transport water in cold versus warm weather will be obtained. Likewise, data following rain events will provide potential impacts to our water balance and water chemistry. The overall goal of the study is to better understand how the BA sluicing impacts water chemistry. By obtaining this data the high recycle rate system can be designed with adequate treatment capabilities to assist with corrosion control, anti-scaling, and particulate control. Understanding potential treatment needs prior to construction is key for protecting system equipment. The additional time to adequately plan and study BA transport water over a year will provide Consumers the appropriate information not only needed to submit a complete "Initial Certification" by October 13, 2021, but to adequately design a system that allows for continued production of safe and reliable energy, while also protecting the environment.

§423.11(t) Factor 1: Design and Procure

As shown in Attachment A, Consumers will start the design process in January 2021, following completion of the conceptual study and anticipates design and procurement to be completed mid-2023. The design process will start in the middle of the current sampling evaluation study to maximize timing, as waiting until late 2021 would push out the project schedule by six or more months. Based on Consumers' Engineers, Project Managers, and Estimators experience, the schedule laid out for design and procurement is appropriate for the scale and magnitude of this project. Project schedules are highly dependent on project complexity, regulatory approvals, availability and lead time of equipment, engineering and design, contractor performance, and commissioning and testing. For example, the BA tank system at Campbell started in early 2015 and was completed in mid to late 2018 with commissioning and testing activities. This project took four years to engineer and execute and did not involve collecting data to understand the water chemistry impact on equipment. Furthermore, the project was able to be constructed while equipment remained in service, had little to no changes to existing plant equipment, and only required a minimal outage to tie the new tank system into the plant. If changes to plant equipment or outages had been required, the project would have required an additional 6 to 12 months for planning and scheduling the outage.

To ensure proper design, understanding the existing and future water chemistry of the BA transport water is required. That work is ongoing and will last until December 2021. Based on preliminary water data, the conceptual high recycle rate study is being completed, and will be published in first quarter 2021. The conceptual study investigates potential reuse opportunities for the BA transport water, and at a high level evaluates various scenarios for installing a high recycle rate system, including preliminary equipment needs, electrical and control needs, as well as piping and routing. This conceptual report will then be used to procure an engineer of record (EOR) to begin design engineering, anticipated in June 2021. While the confirmatory water sampling continues, the EOR will prepare a basis of design for the project with Consumers. This will entail determining how often the BA transport water will recycle and how much BA purge water will need to be discharged. This is based on water chemistry issues that impact the operation of the equipment, along with the volume that can be discharged.

A major component of overall system design is the total volume of BA purge water. According to §423.13(k)(1)(I)(B) the total volume of the discharge authorized in this subsection shall be determined on a case-by-case basis by the permitting authority and in no event shall such discharge exceed a 30-day rolling average of ten percent of the primary active wetted BA system volume. During the design and procurement portion of the project Consumers will be submitting the Initial Certification under §423.19(c)(1) on October 13, 2021 and six months later submitting a permit renewal application on April 4, 2022. Having additional time built into this portion of the project allows for adequate discussions with your office on Initial Certification and the high recycle rate system design.

During 2021, the EOR will also identify any further water separation needed in the plant, along with equipment needs. The EOR will begin working on preliminary design of the system, with 30% design completed in early 2022, and final design (pending EGLE approval of discharge volume) being complete in 4th quarter 2022/1st quarter 2023. Bid documents and specifications will be assembled, and the construction project bid out in 2nd quarter 2023, with a contract issued in summer 2023. Long lead items will be ordered as early as during final design, and depending on valve/pump size, can take up to a year to receive. All three plants will require scheduled outages that must be approved by the Midcontinent Independent System Operator (MISO) in advance. These are expected in late 2023 or early 2024 due when outages are typically allowed.

As mentioned above, having additional time built into this portion of the project allows for adequate time to address any discussions required as a result of the initial certification and NPDES permit renewal and incorporate any changes needed in system design. A revised compliance date, modified prior to the permit renewal, will provide Consumers an agreed upon path for compliance, eliminating the potential risk of not meeting our current compliance deadline of December 31, 2023.

In addition, having a December 31, 2025 deadline will allow Consumers to incorporate any changes to regulations affecting the life of the Campbell facility, as well as other legal obligations. For example, under a settlement agreement approved by the Michigan Public Service Commission (MPSC) in Case No. U-20165, the Company is required to study moving the

Campbell 1 and 2 retirement dates from their current date of 2031 to 2024, 2025, 2026, and 2028 in its next Integrated Resource Plan (IRP) filing. We expect to file this case in June 2021, with a resolution of the case in quarter 2 of 2022. Having an extended compliance date of December 2025 will provide Consumers with additional time to incorporate any retirement decisions coming from our 2021 IRP filing.

Similarly, Consumers expects that the incoming Biden administration will likely put significant regulatory pressure on coal-fired electric generating units, which could affect Consumers' decisions on when to retire those units. Having additional time to comply with SEEG will allow the Company sufficient time to understand the nature and scope of such regulations, and whether they affect the Company's decisions on when to retire certain units.

§423.11(t) Factor 1: Install

Construction will consist of installing new pumps, separating water flows in the plant, installing new pipes and a storage tank, verifying/installing treatment for water chemistry issues, and reinforcing the existing trestle. All of this will require planning around unit outages, which will have to be planned and approved by the MISO.

New operation procedures and testing will be required in 2024, followed by a commissioning and testing period. In order to work out impacts from weather, commissioning and testing would extend into 2025 in order to pick up seasonal impacts on water chemistry, impacts from fuel source variance, and allow time to modify for potential water chemistry adjustments. This additional time is not only imperative for system adjustments, but to ensure operators are adequately trained as well as ensuring the overall compliance with the ELG regulation.

§423.11(t) Factor 4: Historical Actions

While Consumers is requesting an extension of the compliance deadline, it is not because of a failure to prepare. Rather, it is the result of a changing regulatory landscape and the need to ensure the right technology and system and the most cost-efficient pricing. Consumers has been studying waste streams at its Campbell power plant since as early as 2012. Work included:

- Evaluating the feasibility of relocating or rerouting waste streams to accommodate compliance with the anticipated 2015 Best Available Technology (BAT) limitations for implementation at Campbell.
- Evaluating commercially available BA treatment (handling) technologies that would eliminate sluicing and collection of BA in BA ponds. Four commercially available technologies were evaluated to replace the existing BA sluicing operation. As a result of

this study, we determined that neither a local Submerged Flight Conveyor nor a dry ash conveyor system could be retrofitted under the boiler(s) due to physical constraints.

- Developing a conceptual level approach for meeting anticipated BAT limitations. In coordination with the Resource Conservation and Recovery Act (RCRA) Coal Combustion Residual (CCR) rule (40 CFR Part 257 Subpart D), the forced closure of unlined BA ponds required Consumers to segregate waste streams and evaluate the management of BA transport water. For example, coal pile runoff had historically been discharged to the BA ponds comingling with BA transport water. Consumers segregated its coal pile runoff water from its BA transport water in preparation of the ELG rule and to improve the water quality of the planned BA tank system.

- Installation of the BA tank system, which became operational at the end of 2018. Consumers constructed the tank system, not only considering changes to CCR rule, but also with the understanding that changes to the ELG rule could require recirculation of BA transport water.

- Commissioning a conceptual study in 2017 to evaluate, at a high level, the retrofit of Campbell Unit #3 BA tank system to a closed loop system. The study was limited to Unit #3, which is the largest unit at Campbell and provided a high-level assessment of zero liquid discharge options.

Due to the regulatory uncertainty around the postponement of the ELG rule, Consumers made the decision to operate the BA tank system in its current configuration today. In doing this Consumers remained in compliance with NPDES permit requirements, but also allowed the time needed to fully understand any potential changes to the 2015 ELG rule.

Summary

Consumers is requesting a modification to extend the compliance deadline out to December 31, 2025 so that once the high recycle rate system is active, time is available to adjust post system start-up to account for the new system operation, variations in seasons and fuel source, but prior to the compliance deadline. Without the compliance deadline extension, and additional time needed to address potential issues, the Campbell plant could entirely be shut down during periods of system upgrades – with potential serious electric reliability and cost consequences to our customers. Additional time will ensure the system can meet the 2020 Reconsideration Rule ELG limits once the compliance deadline has been met.

If you have any questions or need additional information, please do not hesitate to contact me at (517) 788-1429 or by email at rachel.proctor@cmsenergy.com.

Sincerely,

Rachel Proctor

Rachel Proctor, P.E.
Consumers Energy – Environmental Services
Senior Engineer

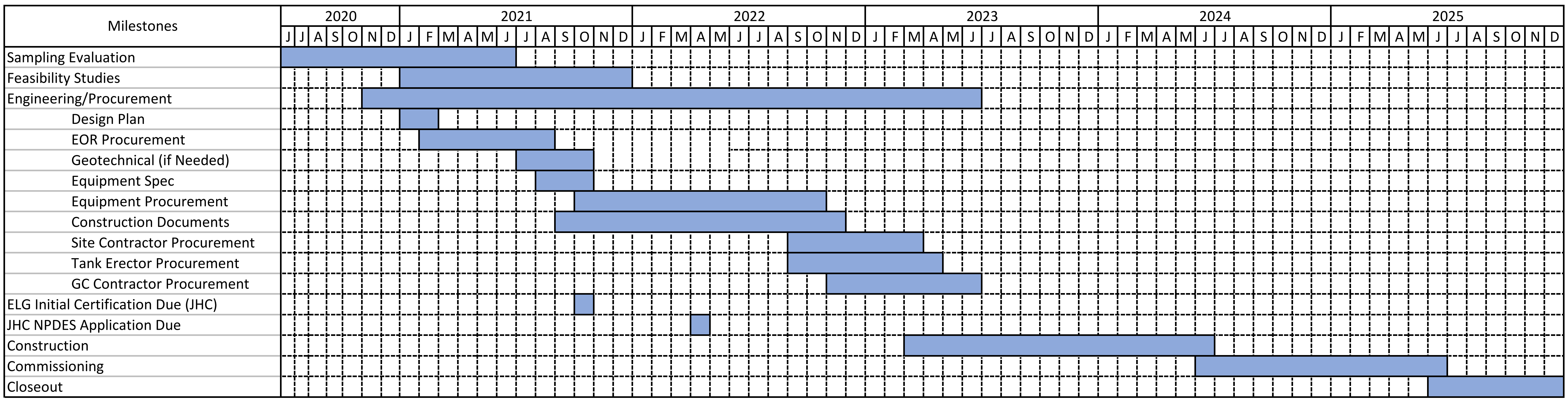
Electronically Distributed

CC: Tarek Buckmaster, Supervisor, Industrial and Storm Water Permits Unit, WRD, EGLE
Mike Worm, Supervisor, Grand Rapids District Office, WRD, EGLE
Chris Veldkamp, Grand Rapids District Office, WRD, EGLE
Kristin Melcher, Consumers Energy Company, JHC
Joseph Firlit, Consumers Energy Company, JHC
James Roush, P22-122
Heather Dziedzic, P22-326
Scott Sinkwitts, Esq. EP11-438
J H Campbell 1& 2 NPDES Application File

Attachment A - J.H. Campbell Compliance Schedule

Consumers Energy Company

J.H. Campbell Steam Electric Effluent Guideline - 2020 Reconsideration Rule Compliance Schedule



U20963-MEC-CE-032
Page **1** of **1**

Question:

25. Refer to page 10, line 1 through page 11, line 22 of the Direct Testimony of Heather A. Breining, which discusses Consumers' plans to comply with SEEG.
a. Further refer to page 11, lines 1-3. Has the Company submitted or considered submitting a "notice of planned participation" for Campbell Units 1 and 2 that would exempt those units from SEEG compliance due to the cessation of coal combustion by 2028? If not, please explain why not.
b. If Campbell 1 and 2 retire, that would reduce the Campbell plant's capacity by approximately 43% (Hugo Direct at p. 6), and would presumably reduce the volume of Campbell's bottom ash and other waste streams. Has the Company evaluated whether a smaller SEEG system could be implemented if Campbell Units 1 and 2 retire by 2028?
i. If so, please provide a copy of such evaluation, including any supporting engineering reports, workpapers, or other documents.
ii. If not, please explain why the Company has not evaluated this scenario.
c. Further refer to page 9, line 7, and to 40 C.F.R. § 423.19(e). For any of the Campbell units, has the Company evaluated whether to invoke the Reconsideration Rule's low capacity factor utilization subcategory?
i. If so, please provide the results of such evaluation, including any supporting workpapers or documents, and describe the estimated cost impact of this option.
ii. If not, please explain why the Companies have not evaluated this option.

Response:

a. At this time, the Company has not submitted a "notice of planned participation" for Campbell Units 1 and 2 because the Company has not yet completed an early retirement analysis of the Campbell Units 1 and 2. In June 2021, the Company will be filing an updated Integrated Resource Plan (IRP). An early retirement analysis of Campbell Units 1 and 2 will be included as part of that filing.

b. In the final SEEG rule, the EPA includes an off-ramp for units that commit to retiring by year-end 2028. What the final rule fails to do is account for sites with multiple units with shared systems. At Campbell, all three units have one shared system. As a result, SEEG compliance will still be required for Unit 3 by year-end 2023.

c. The Company has not evaluated whether to invoke the Reconsideration Rule's low capacity factor utilization subcategory. The low capacity allows the units to run at 10% capacity or less for a 2-year average. This would result in units 1 and 2 sitting idle for 11 months per year, but still requiring maintenance and staff to run when needed. The Company's currently approved IRP filing calls for utilizing these units more than 1 month a year and the scenario, as set forth above, would not be consistent with the Company's approved IRP. In June 2021, the Company will be filing an updated IRP. An early retirement analysis of Campbell Units 1 and 2 will be included as part of that filing.

Heather A. Breining

HEATHER A. BREINING
April 9, 2021

Question:

26. Refer to page 12, line 13 through page 13, line 7 of the Breining Direct Testimony.
a. If the Company has a more detailed version of its SEEG compliance plan, please provide a copy of such plan.
b. Please produce the wastewater studies the Company conducted in 2020 to evaluate bottom ash ("BA") transport water chemistry.
c. Please explain in detail the results of the preliminary testing that has allowed the Company to reduce its projected SEEG compliance costs by $27 million. Please also produce the underlying data and reports used to support those results.
d. How long does the Company anticipate collecting data to characterize the bottom ash transport water at the Campbell site? Please also identify any costs associated with this data collection.
e. Please describe the Company's estimated timeline for procuring contractors and equipment to design the closed loop system for Campbell.
f. Please provide a detailed explanation for how the Company calculated the costs associated with the procurement of contractors and equipment that will be used to design Campbell's closed loop system. Please also provide the estimated cost of each phase of designing and constructing the closed loop system.
g. Further refer to page 8, lines 11-14. Under the Company's current SEEG compliance plan, would the system installed at Campbell be a "zero-liquid discharge" system, or a system that could potentially "discharge up to 10% of the primary active wetted BA system volume on a 30-day rolling average"?
i. If the latter, has Consumers evaluated the additional cost that would be necessary to develop a zero-liquid discharge system? If yes, please identify the estimated cost for such a system.

Response:

a. A Conceptual Design report is currently being prepared by Golder Associates and is not yet complete. The report is anticipated to be complete by mid-May. A copy can be provided upon request once finalized.
b. The wastewater studies started in 2020 are ongoing through the end of 2021. We will continue to sample water streams once a month through 4th quarter of 2021. A bench scale test simulating cycles through the bottom ash will be complete in 2nd quarter of 2021. Please see U20963-MEC-CE-033-Breining_ATT_1 for the preliminary water quality testing results and findings.
c. The wastewater studies completed in 2020, and continuing through 4th quarter of 2021, was performed at several locations along our discharge path, upstream of the NPDES outfall. In addition, compliance monitoring is conducted according to our NPDES permit and is compliant with our NPDES discharge limits. As part of the ongoing wastewater studies, samples were collected of the low volume miscellaneous wastewater (LVMW). Results to date show that the LVMW meets current NDPES discharge limits upstream of the NPDES outfall (average TSS 4.3 mg/L). As of now, SEEG allows discharge of the LVMW provided it meets the NPDES discharge limits at the outfall. The testing results show that we met the NPDES discharge limits, which allowed us to eliminate the need for installing a wastewater treatment plant on site, reducing our costs by $27M. Preliminary water

quality testing results and findings are documented in the technical memorandum by Golder, dated February 18, 2021 "Conceptual Design and Modeling Basis Technical Memorandum".

d. The wastewater studies started in June 2020 with current plans to collect data through December 2021. Cost for water sampling in 2021 is $75,000.

e. The Company has prepared and sent out a request for proposal for engineering services to design the closed loop system in February 2021. The engineer of record is expected to be under contract by June of 2021. Based on the current December 2023 compliance deadline, the request for quote for a contractor to construct the system is scheduled to be issued June of 2022, with a contact in place September of 2022. Long lead time equipment would be procured early following completion of select design elements. The timing to procure long lead equipment will be determined after the engineer of record is under contract.

f. The Company has an internal cost estimating group that follows RS Means methods to calculate the cost estimate. The conceptual layout of equipment and piping was provided to our cost estimators, who then used the information to determine material quantities. Based on the quantity take offs, the estimator built out required construction equipment, staff and time required to complete the project, and applied appropriate rates from sources such as RS Means and Blue Book. Lastly, the estimator added our internal costs to the estimate. Design costs are estimated at $2.3M and construction costs are estimated at $20.4M. Please refer to (Breining_WP_1) for the SEEG cost estimate.

g. The proposed system will utilize the SEEG provision that allows discharge up to 10% of the primary active wetted BA system volume on a 30-day rolling average. This discharge is required in place to control water chemistry of the system and will be regulated through the NPDES site permit.

h. A zero liquid discharge system would require installation of a new bottom ash removal system such as a submerged flight conveyor, which would be installed below the existing boiler. This would necessitate removing the bottom half of the boiler and associated plant modifications. In 2014 a remote submerged flight conveyor was considered, and cost was estimated at $65M, escalated to 2023 costs this would be $85M. During the ongoing conceptual study, CEC considered other options to reuse the bottom ash water including as make up water in the JHC unit 3 SDA and for conditioning of fly ash. Using this water in either of those systems would displace recycled process water. In addition, the water demands of these systems are well under 10% of the water that the bottom ash tank system uses on a daily basis.

Heather A. Breining

HEATHER A. BREINING
April 9, 2021

Question:

27. Refer to Exhibit A-60 (HAB-2).

   a. Please confirm that the Company has classified the SEEG expenditures listed in this exhibit as being for the Campbell site commons (as opposed to a particular unit(s)).

      i. If not confirmed, please provide a breakdown of the SEEG compliance capital expenditures by unit.

      ii. If confirmed, please confirm that 43% of these SEEG-related costs would be allocated to Campbell 1 and 2, and 57% of these costs would be allocated to Campbell 3.

         (a) If confirmed, please confirm that the costs allocated to Campbell 1 and 2 would be further split 42/58 between those two units. If not, please explain why not.

         (b) If not confirmed, please describe how these costs would be allocated between Campbell Units 1, 2, and 3.

   b. Please produce any budgets, financial or engineering reports, workpapers, or other documents supporting the projected test year spending.

   c. In Case No. U-20697, Consumers listed separate SEEG projects for Campbell 1 and 2 (Work ID 5453 & 5522) and Campbell 3 (Work ID 5456 & 5523). (See, e.g., U20697-MEC-CE-545-Hugo_ATT_1, lines 9-10, 15-16; Case No. U-20697, Hugo workpaper WP-SAH-22, lines 9-10, 14-15.) Please confirm that the Company has reclassified these previously separate projects as a single project (Work ID 5523 – see WP-SAH-50, line 52).

      i. If not confirmed, please explain why not.

Response:

a. Confirmed. The Campbell site has a shared water discharge system. For budgetary purposes, the split between Units 1-2 and Unit 3 would be based on the capacity of the said units. Thus, 43% of the costs could be apportioned to Units 1 and 2 and the remaining 57% could be apportioned to Unit 3.

b.

Objection of Counsel: **Consumers Energy Company objects to this discovery request to the extent that it is unclear, overly broad, and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:**

The following SEEG-related confidential business document was provided under the Part III Filing Requirements, named: Conf - CBI_1662420-1000-1040-2-R-A-JHC Water Balance Model

08MAR17.pdf. The reference document is a draft report prepared by Golder Associates Inc. (Golder) for Consumers Energy Company (CEC) to present a water and chemical mass balance model developed for a bottom ash tank system which was proposed for construction at the JH Campbell Generating Plant (JHC). The purpose of the model is to improve CEC's understanding of discharge quality following construction of the bottom ash tanks. The model may also be used to support ash conveyance and process water management decisions at JHC by providing CEC with a planning tool to better understand the likely future discharge flow rates and quality.

Please also refer to work paper (Breining_WP_1) for the SEEG cost estimate which supports the test year dollars.

c. Not Confirmed. Work ID 5453 for Campbell 1 and 2 and Work ID 5456 for Campbell 3 have been combined into a single Work ID of 5456. Work ID 5522 for Campbell 1 and 2 and Work ID 5523 for Campbell 3 have been combined into a single work ID of 5523.

Heather A. Breining

HEATHER A. BREINING
April 13, 2021

U20963-MEC-CE-651
Page **1** of **1**

Question:

16. Refer to your response to MEC-CE-34(c), which states that "Work ID 5453 for Campbell 1 and 2 and Work ID 5456 for Campbell 3 have been combined into a single Work ID of 5456." Further refer to U20963-MEC-CE-013_ATT_44, which presents planned capital expenditures at Campbell for each of the years 2021-25, but does not include a project with Work ID 5456.

a. Please confirm that the Company is not seeking rate recovery for project 5456 (formerly projects 5453 and 5456) in this case.

i. If not confirmed, please explain why this project is not included in the capital projects presented in this current case.

ii. If not confirmed, please identify which project(s) presented in U20963-MEC-CE-013_ATT_44 incorporates projects 5453 and/or 5456.

b. If project 5456 was inadvertently omitted from U20963-MEC-CE-013_ATT_44:

i. Please supplement U20963-MEC-CE-013_ATT_44 with this project, and provide all of the information requested in MEC-CE-13(b)(i)-(v).

ii. Are there are other capital and/or major maintenance projects planned for Campbell that were omitted from U20963-MEC-CE-013_ATT_44? If so, please identify those projects and provide the information requested in MEC-CE-13(b)(i)-(v).

Response:

a. Confirmed.
i. See response to subpart (a).
ii. See response to subpart (a).

b. See response to subpart (a).
i. See response to subpart (a).
ii. To date, no projects have been identified which have been omitted from U20963-MEC-CE-013_ATT_44.

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

U20963-MEC-CE-652 (Partial)
Page **1** of **1**

Question:

17. Refer to U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_6.

   a. Please confirm that the projected costs of project 5523 (JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.) is $1,928,742 in 2021, and $15,421,498 in 2022.

      i. If not confirmed, please identify the project costs and provide an updated copy of U20963-MEC-CE-013_ATT_44.

   b. Please confirm that the Company has not performed any economic analysis comparing the costs and benefits of different SEEG compliance options.

      i. If not confirmed, please identify and produce a copy of any such analysis (as well as any supporting workpapers).

   c. Please confirm that the only documentation supporting these 2021 and 2022 expenditures are U20963-MEC-CE-013_ATT_6 and Breining workpaper WPHAB-1. If not confirmed, please provide any other supporting documentation.

Response:

a. Confirmed.

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

Question:

17. Refer to U20963-MEC-CE-013_ATT_44 and U20963-MEC-CE-013_ATT_6.
    a. Please confirm that the projected costs of project 5523 (JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.) is $1,928,742 in 2021, and $15,421,498 in 2022.
        i. If not confirmed, please identify the project costs and provide an updated copy of U20963-MEC-CE-013_ATT_44.
    b. Please confirm that the Company has not performed any economic analysis comparing the costs and benefits of different SEEG compliance options.
        i. If not confirmed, please identify and produce a copy of any such analysis (as well as any supporting workpapers).
    c. Please confirm that the only documentation supporting these 2021 and 2022 expenditures are U20963-MEC-CE-013_ATT_6 and Breining workpaper WPHAB-
        i. If not confirmed, please provide any other supporting documentation.

Response:

a. Confirmed.

b. This is not confirmed. The Company has performed several analyses comparing the costs and benefits of different SEEG compliance options, particularly as the SEEG and related Coal Combustion Residual (CCR) regulations have changed. For instance, it undertook a technology feasibility study and wastewater studies to accommodate the development of a least-cost design, engineering and construction of the technologies to meet the NPDES permit renewal application and expected operational compliance dates. These studies will save the Company substantial costs by avoiding the need to install a wastewater treatment facility. These studies were necessary to inform and shape the SEEG and CCR compliance strategies as we navigated through an evolving regulatory environment.

   For example, as described in the 2014 electric rate case U-17735, the Company focused on developing a CCR management strategy for Coal Combustion Residuals (CCRs) that complied with the minimum construction standards outlined in the proposed rule under Subtitle D of the Resource Conservation Recovery Act (RCRA), while also complying with the proposed SEEG rule. At that time, the CCR management strategy consisted of replacing the existing bottom ash ponds with a Dry Bottom Ash (DBA) handling system, installing a water treatment system, removing all wastewater and coal combustion residual from the Campbell bottom ash ponds, treatment of the wastewater, and placement of the CCRs in the existing landfill. The DBA had high costs but was deemed necessary for compliance with the proposed SEEG and RCRA regulations. A copy of the D.E. Karn Unit 1-2 and J.H. Campbell Unit 1-3 Bottom Ash Handling Wet-to-Dry Conversion Technology Evaluation and Feasibility Study was provided at Attachment 2 in discovery response 17735-MEC-CE-55.

   After the finalization of the RCRA and SEEG regulations in 2015, additional evaluations were performed and the CCR management strategy changed. It was determined that a lower cost option would be to cease sending CCRs to J.H. Campbell's bottom ash ponds and replace them with a concrete tank system. We could then continue wet sluicing bottom ash to this tank system and manage the transport water in a closed loop system. This strategy was a much lower cost option than the dry bottom ash handling system and was approved by the Michigan Public Service Commission in case the 2016 electric rate case U-17990.

c. Confirmed.

Heather A. Breining

HEATHER A. BREINING
May 14, 2021

Environmental Services

U20963-MEC-CE-653
Page **1** of **1**

Question:

18. Refer to page 10, lines 2-3, of the Breining Direct Testimony. Please also refer to page 14 of draft Permit No. MI0001422 for the J.H. Campbell Power Plant.
a. Does the Company agree that the Steam Electric Effluent Guidelines ("SEEG") require it to make bottom ash transport water compliance retrofits to its coal units by 2025 unless the Company submits a 423.19(f) notice that it will retire the coal units by 2028? If not, please explain why not.
b. Further refer to your response to MEC-CE-32(b). Please confirm that if draft Permit MI0001422 is finalized without substantive changes, the compliance
deadline for Unit 3 would shift back two years, to December 31, 2025.
i. If not confirmed, please explain why not.
c. Further refer to page 7 of the January 11, 2021 letter from Rachel Proctor, Consumers Energy, to Christine Aiello, EGLE (re: "Consumers Energy Company,
J.H. Campbell Complex, NPDES Permit No. MI0001422 Permit Modification,Steam Electric Effluent Limitation Guidelines"). Please provide a copy of the 2017
conceptual study that "evaluate[d], at a high level, the retrofit of Campbell Unit #3 BA tank system to a closed loop system."

Response:

a. According to 40 CFR 423.13(k)(1)(I) Dischargers must meet the discharge limitation in this paragraph by a date determined by the permitting authority that is as soon as possible beginning October 13, 2021, but no later than December 31, 2025. Both Karn and Campbell current NPDES permits have a compliance date of December 31, 2023, so as of today December 31, 2023 is the current compliance date to make bottom ash transport water compliance retrofits to its coal units. If the permit modification request submitted on January 11, 2021 is approved by EGLE, the new compliance date for Campbell will be December 31, 2025 unless the Company submits a 423.19(f) notice that it will retire the coal units by 2028.
b. Yes, if draft Permit MI0001422 is finalized without substantive changes the compliance deadline for units 1, 2, and 3 will be December 31, 2025.
c. Please see Attachment 1.

Heather A. Breining

HEATHER A. BREINING
May 12, 2021

Environmental Services

U20963-MEC-CE-654
Page **1** of **1**

Question:

19. Refer to your response to MCE-CE-32(b).
    a. Please confirm that the Company has not evaluated whether a smaller SEEG system could be implemented if Campbell Units 1 and 2 retire by 2028.
        i. If not confirmed, please supplement your response to 32(b) with any documents reflecting such evaluation.
    b. Is it the Company's belief that the size of a bottom ash transport water ("BATW") system would not be affected by the volume of BATW produced by a coal-fired generating unit? If yes, please explain the basis for your belief.
    c. Please confirm that the Company has not conducted any analysis of the potential cost savings for SEEG compliance if Campbell 1 and 2 ceased coal-burning activities by 2028.
        i. If not confirmed, please provide such analysis.

Response:

a. No capital cost savings have been quantified as a result of an early retirement of any of the JHC1 and/or JHC2. The reasons being: 1.) the current SEEG compliance date is 12/31/23 and any early retirement scenario(s) would fall beyond that date; 2.) JHC3 is planned to continue to operate through 2039 and must be in compliance with SEEG; 3.) Even if an exception was granted for JHC3 to delay compliance until the JHC1 and/or JHC2 units retire, there would likely only be a savings in pipe and/or pump sizing. The current cost estimates are order of magnitude cost estimates and are not detailed enough to be able to quantify the potential cost savings.

b. The bottom ash transport and handling system at the Campbell site is currently sized for units 1, 2, and 3 combined. Units 1 and 2 enter primary tank A while Unit 3 enters primary Tank B. At this point in the flow path the primary tanks enter secondary tanks and comingle all units' bottom ash transport water prior to discharge. The bottom ash tank system is already constructed. Units 1, 2, and 3 do not always operate at the same time so the bottom ash tank system is designed to handle flows during operation of all 3 units or each unit operating separately. Once units retire the bottom ash tank system will continue to operate in its current state but will only receive BATW from the unit in operation. As a result, the recycle system sizing does not explicitly depend on the size of the coal unit. As mentioned above under subpart a) there would only be a savings in pipe and or pump sizing.

c. See above response to a.

Heather A. Breining

HEATHER A. BREINING
May 12, 2021

Environmental Services

Question:

20. Refer to your response to MEC-CE-33.
a. Once completed, please provide a copy of the Conceptual Design report currently being prepared by Golder Associates (i.e., the report expected to be finished in mid-May).
b. Further refer to your responses to MEC-CE-33(g) and 33(h).
i. If the zero liquid discharge system were implemented, which of the Campbell units would have the bottom half of its boiler removed?
ii. Please provide a copy of the 2014 cost estimate.
iii. Has the Company prepared a cost estimate for a zero liquid discharge system since 2014? If so, please provide that cost estimate and the date
when it was created.

Response:

a) The final report has not yet been received.
b) A zero liquid discharge system is not being implemented. As stated in my response to 33(g), the proposed system will utilize the SEEG provision that allows discharge up to 10% of the primary active wetted BA system volume on a 30-day rolling average.

Heather A. Breining

HEATHER A. BREINING
May 12, 2021

Question:

20. Refer to your response to MEC-CE-33.

a. Once completed, please provide a copy of the Conceptual Design report currently being prepared by Golder Associates (i.e., the report expected to be finished in mid-May).

b. Further refer to your responses to MEC-CE-33(g) and 33(h).

i. If the zero liquid discharge system were implemented, which of the Campbell units would have the bottom half of its boiler removed?

ii. Please provide a copy of the 2014 cost estimate.

iii. Has the Company prepared a cost estimate for a zero liquid discharge system since 2014? If so, please provide that cost estimate and the date when it was created.

Supplemental Response:

b) A zero liquid discharge system is not being implemented. To install a zero liquid discharge system, all three J.H. Campbell units would require significant modification to the boiler in order to install a submerged flight conveyor. This would include removing the bottom of the boilers at each unit in order to gain the space necessary to install the equipment.

Refer to page 38 of Attachment 1 for the Bottom Ash Handling, Wet-to-Dry Conversion Technology Evaluation and Feasibility Study for the J.H. Campbell dry bottom ash cost estimate.

Heather A. Breining

HEATHER A. BREINING
June 3, 2021

Question:

10. Refer to MEC-CE-655(a), which asked the Company to provide a copy of the Golder Associates Conceptual Design report once that report is completed. Further refer to your response, which states that "[t]he final report has not yet been received."

a. When this final report is received – even if received after you respond to this discovery request – please supplement your response to MEC-CE-655(a) by producing a copy of the report. (Please consider this to be an ongoing request for supplementation that continues until the record in this case has closed.)

b. Has the Company received a draft version of this report? If so, please provide a copy of the draft report.

Response:

Objection of Counsel: Consumers Energy Company objects to the productions of documents which are still under development and may be inaccurate or incomplete. Subject to that objection, and without waiving it, the Company provides the following response:

a. When the final report is received, the Company will produce a copy of the report in a supplemental response to MEC-CE-655(a).

b. The Company has received a preview of a draft version of the report but the report is still under development by Golder Associates and is not yet final.

Heather A. Breining

HEATHER A. BREINING
June 2, 2021

Environmental Services

Question:

1. Referencing page 10 of the direct testimony of witness Heather Breining, it is stated that the Company is requesting an extension of deadlines for compliance with the SEEG ruleset at its Campbell facility:

a. Is there any kind of established timeline for EGLE to consider and decide on the Company's request for an extension of the deadline for SEEG compliance?

i. If so, please provide the deadline for EGLE to make such a determination;

ii. If there is no established timeline for this decision by EGLE, has the Company received any correspondence or other updates from EGLE that provide additional information on the progress of this request?

iii. Will the determination of the deadline by EGLE impact both the anticipated scope and timing of the work needed for SEEG compliance?

b. One of the reasons provided for this extension request is to allow for "adequate planning and preparation of the Company's compliance with the rule." Previously the Company has stated that it does not anticipate the updated ruleset would require any changes to the design of its high recycle rate system.

i. Does the Company still anticipate no new design changes in response to the updated SEEG ruleset? What additional steps must be taken to ensure that the Company's currently planned design is compliant with these rules?

ii. Aside from the wastewater studies referenced in testimony, is the Company conducting, either itself or through a contracted 3rd party, any additional studies that may determine the requirements of its high recycle rate system to achieve SEEG compliance?

iii. If the Company has conducted or is currently conducting studies, either internally or through a contracted 3rd party, to further evaluate the compliance of its project designs with the final SEEG ruleset, please provide any study details/scope and results from these studies, or the anticipated completion date of such studies if results are not available.

c. Please provide a projection of total annual expenses incurred for SEEG compliance at Campbell for each year presented in this case and all future years until the deadline for compliance assuming:

i. The Company must achieve compliance by the currently established deadline of December 31, 2023;

ii. The Company is granted an extension of this compliance deadline until December 31, 2025.

Response:

a) A permit modification request was submitted on January 11, 2021. The draft permit is currently on public notice until May 14, 2021 and incorporates a compliance date of December 31, 2025.

b) The scope of work will not materially change based on EGLE's decision. To ensure compliance with the rule, the Company is collecting additional water samples throughout 2021 and completing a bench scale test scheduled to be completed in the second quarter of 2021, which will mimick the impact of cycling water through the system. In addition, a the Company will be hiring a third party design engineer in June 2021 to start work on the conceptual engineering to determine water chemistry and heat impacts on the existing equipment, and completing calculations to support required blow down volume to meet maintain water chemistry. Conceptual design work is scheduled to be completed in November/December 2021. Please refer to Attachment 1 for a copy of the NPDES Permit modification request submitted on January 11, 2021. No other studies, other than the referenced wastewater studies, have been conducted.

c) Please refer to the Total Estimate Summary tab in WP-Breining-1 for the SEEG cost projections necessary for a 2023 compliance. Please refer to the Total Estimate Summary tab in Attachment 2 for the SEEG cost projections necessary for a 2025 compliance.

Heather A. Breining

HEATHER A. BREINING
April 26, 2021

Environmental Services

PERMIT NO. MI0001422

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Water Pollution Control Act, 33 U.S.C., Section 1251 *et seq*., as amended; Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06,

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201

is authorized to discharge from the **Consumers Energy Company, J. H. Campbell Power Plant** located at

17000 Croswell St.
West Olive, MI 49460

designated as **CECO-J H Campbell Power Plt**

to the receiving waters named Lake Michigan and the Pigeon River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in this permit.

This permit is based on a complete application submitted on March 22, 2016, as amended through September 1, 2016; and a complete modification request submitted on January 11, 2021.

This permit originally took effect on June 1, 2018. This modified permit takes effect on DRAFT. The provisions of this permit are severable. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term in accordance with applicable laws and rules. On its original effective date, the permit superseded National Pollutant Discharge Elimination System (NPDES) Permit No. MI0001422 (expiring October 1, 2016).

This permit and the authorization to discharge shall expire at midnight on **October 1, 2022**. In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit an application that contains such information, forms, and fees as are required by the Michigan Department of Environmental Quality (Department) by **April 4, 2022**.

Issued: May 29, 2018. Modified (major) DRAFT.

Christine Alexander, Manager
Permits Section
Water Resources Division

PERMIT FEE REQUIREMENTS

In accordance with Section 324.3120 of the NREPA, the permittee shall make payment of an annual permit fee to the Department for each October 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by January 15 for notices mailed by December 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after December 1.

Annual Permit Fee Classification: Industrial-Commercial Major

In accordance with Section 324.3118 of the NREPA, the permittee shall make payment of an annual storm water fee to the Department for each January 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by March 15 for notices mailed by February 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after February 1.

CONTACT INFORMATION

Unless specified otherwise, all contact with the Department required by this permit shall be made to the Grand Rapids District Office of the Water Resources Division. The Grand Rapids District Office is located at State Office Building, Fifth Floor, 350 Ottawa Ave NW, Unit 10, Grand Rapids, Michigan, 49503-2341, Telephone: 616-356-0500, Fax: 616-356-0202.

CONTESTED CASE INFORMATION

Any person who is aggrieved by this permit may file a sworn petition with the Michigan Administrative Hearing System within the Michigan Department of Licensing and Regulatory Affairs, c/o the Michigan Department of Environment, Great Lakes, and Energy, setting forth the conditions of the permit which are being challenged and specifying the grounds for the challenge. The Department of Licensing and Regulatory Affairs may reject any petition filed more than 60 days after issuance as being untimely.

PART I

Section A. Limitations and Monitoring Requirements

1. Effluent Limitations, Monitoring Point 001A

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 984.841 MGD of noncontact cooling water; intake screen backwash; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, and water from floor drains; bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; storm water; leachate retention pond water; reverse osmosis backwash and reject water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 001A through Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			**Maximum Limits for Quality or Concentration**				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	(report)	(report)	MGD	---	---	---	Daily	Report Total Daily Flow
Total Residual Oxidant (TRO) – See Part I.A.1.g.								
During Chlorination – No Bromine Use								
Total Residual Chlorine (TRC) Discharge Time			---	---	(report)	min/day	Daily	Report Total Discharge Time
Continuous (greater than 160 min/day)		---	---	---	38	ug/l	Daily	Grab
				Daily Average	**Instantaneous Maximum**			
Intermittent (less than/equal to 160 min/day)				200	300	ug/l	Daily	Grab
During Bromination – Alone or With Chlorine								
Intermittent (less than/equal to 120 min/day)				(report)	50	ug/l	Daily	Grab
					Maximum Daily			
TRO Discharge Time		---	---	---	120	min/day	Daily	Report Total Discharge Time
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Copper, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
EVAC (as amine)	---	---	---	---	78	ug/l	Every 2 Hrs During Discharge	Grab
Temperature								
Intake (Unit 3 intake)	---	---	---	(report)	(report)	°F	Daily	Continuous
Discharge	---	---	---	(report)	(report)	°F	Daily	Continuous
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual

PART I

Section A. Limitations and Monitoring Requirements

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Lake Michigan. Intake temperature monitoring shall be taken at the Unit 3 intake.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Analytical Methods and Quantification Levels for Total Phosphorus and Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Phosphorus and Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Phosphorus and Total Copper, shall be 10 ug/l and 1.0 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

PART I

Section A. Limitations and Monitoring Requirements

g. Total Residual Oxidant (Chlorine and Bromine) Requirements
Total Residual Oxidant (TRO) shall be analyzed in accordance with Part II.B.2. of this permit. TRO monitoring is only required during periods of chlorine or bromine use and subsequent discharge. The limitations specified in Part I.A.1. for the intermittent discharge of chlorine alone apply only when the discharge of chlorine alone is less than or equal to 160 minutes per day, otherwise the limitations for continuous discharge of chlorine alone apply. Authorization to discharge bromine alone or with chlorine is limited to 120 minutes per day at the limitations specified in Part I.A.1., with the additional requirement that any discharge of chlorine is further restricted to a concurrent discharge with bromine (no additional discharge of chlorine is authorized for that day).

During the intermittent discharge of chlorine without bromine ("During Chlorination – No Bromine Use"), the daily average concentration reported for TRC shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a chlorine discharge event, with the additional limitation that no single sample may exceed 300 ug/l.

During the intermittent discharge of bromine alone or with chlorine ("During Bromination – Alone or With Chlorine"), the daily average concentration reported for TRO shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a bromine, or bromine plus chlorine, discharge event, with the limitation that no single sample may exceed 50 ug/l of TRO.

The permittee shall enter "*G" on the Discharge Monitoring Report for the TRO discharge modes not being used.

The permittee may use dehalogenation techniques to achieve the applicable TRO limitations, using sodium thiosulfate, sodium sulfite, sodium bisulfite, or other dehalogenating reagents approved by the Department. The quantity of the reagent(s) used shall be limited to 0.6 times the stoichiometric amount of TRO for sodium thiosulfate, 1.5 times the stoichiometric amount of TRO for sodium bisulfite, and 1.8 times the stoichiometric amount of TRO for sodium sulfite. The TRO samples taken to determine the amount of each chemical to add shall be taken upstream of dehalogenation.

h. Zebra Mussel Control Requirements
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than 12 hours per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge.

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report "<" the quantification level used by the analyzing laboratory on the DMR.

i. Total Copper and Total Iron Monitoring
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 001A.

j. Temperature Monitoring
When the continuous temperature monitoring system is inoperative, the effluent daily maximum temperature may be reported on a single daily reading.

PART I

Section A. Limitations and Monitoring Requirements

k. Acid Cleaning
The periodic use of Muriatic acid for cleaning sodium hypochlorite injection systems nozzles is approved.

l. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

2. Effluent Limitations, Monitoring Point 001B (Ash Pond System Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 7.77 MGD of bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject, and water from floor drains; storm water; leachate retention pond water; and groundwater seepage from ash ponds and recirculation pond from Monitoring Point 001B through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Annual Monitoring
Annual samples shall be taken during the month of April. If the facility does not discharge during this month, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

PART I

Section A. Limitations and Monitoring Requirements

d. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

3. Effluent Limitations, Monitoring Point 001C (Plant Oil/Water Separator Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 9.65 MGD of noncontact cooling water; low volume wastewater, which includes but is not limited to: boiler blowdown, recirculating house service water, laboratory and sampling streams, and water from floor drains; treated coal pile runoff; and storm water from Monitoring Point 001C through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	25	40	mg/l	Monthly	Grab
Oil & Grease	---	---	---	---	10	mg/l	Monthly	Grab

a. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Units 1 & 2 intake channel.

b. Monitoring Frequency Reduction for Oil & Grease
After the submittal of 12 months of data, the permittee may request, in writing, Department approval for a reduction in monitoring frequency for Oil & Grease. This request shall contain an explanation as to why the reduced monitoring is appropriate. Upon receipt of written approval and consistent with such approval, the permittee may reduce the monitoring frequency indicated in Part I.A.3. of this permit. The monitoring frequency for Oil & Grease shall not be reduced to less than Annually. The Department may revoke the approval for reduced monitoring at any time upon notification to the permittee.

PART I

Section A. Limitations and Monitoring Requirements

4. Effluent Limitations, Monitoring Point 002A (Ash Pond Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 10.45 MGD of bottom ash transport water; economizer ash wastewater; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater which includes but is not limited to: ion exchange wastewater, boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject water, and water from floor drains; storm water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 002A through Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	(report)	(report)	MGD	---	---	---	2X Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Arsenic	---	(report)	lbs/day	---	(report)	ug/l	Quarterly	Grab
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Selenium	0.47	(report)	lbs/day	5.3	(report)	ug/l	Quarterly	Grab
EVAC (as amine), see Part I.A.4.h.		---	---	---	78	ug/l	See Permit Requirements	Grab
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to the Pigeon River.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended

PART I

Section A. Limitations and Monitoring Requirements

solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly and Annual Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. Annual samples shall be taken during the month of April. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Total Copper and Total Iron Monitoring
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 002A.

g. Analytical Methods and Quantification Levels for Total Arsenic, Total Copper, and Total Phosphorus
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Arsenic, Total Copper, and Total Phosphorus shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Arsenic, Total Copper, and Total Phosphorus shall be 1.0 ug/l, 1.0 ug/l, and 10 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

h. Zebra Mussel Control Requirements
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than five (5) days per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge. Upon initiation of each EVAC treatment, samples shall be collected at Monitoring Point 002A at least once every three hours for a twelve (12) hour period. Once treatment is complete following the twelve (12) hour period, sampling will occur once daily the following day for five consecutive days to show that the concentration (as an amine) measured at Monitoring Point 002A is below detection (zero).

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report “<” the quantification level used by the analyzing laboratory on the DMR.

i. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

PART I

Section A. Limitations and Monitoring Requirements

5. Effluent Limitations, Monitoring Point 002C

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 1.092 MGD of chemical metal cleaning wastewater from Monitoring Point 002C through Monitoring Point 002A and Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Copper, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

PART I

Section A. Limitations and Monitoring Requirements

6. Request for Discharge of Water Treatment Additives

Prior to discharge of any water treatment additive, the permittee shall obtain written approval from the Department. Requests for such approval shall be submitted via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Instructions for submitting such a request may be obtained at http://www.michigan.gov/deqnpdes (near the bottom of that page, click on one or both of the links located under the Water Treatment Additives banner). Additional monitoring and reporting may be required as a condition for the approval to discharge the additive.

A request to discharge water treatment additives shall include all of the following usage and discharge information for each water treatment additive proposed to be discharged:

a. Safety Data Sheet (formerly known as Material Safety Data Sheet);

b. the proposed water treatment additive discharge concentration with supporting calculations;

c. the discharge frequency (i.e., number of hours per day and number of days per year);

d. the outfall and monitoring point from which the product is to be discharged;

e. the type of removal treatment, if any, that the water treatment additive receives prior to discharge;

f. the product's function (i.e. microbiocide, flocculant, etc.);

g. a 48-hour LC_{50} or EC_{50} for a North American freshwater planktonic crustacean (either *Ceriodaphnia sp., Daphnia sp., or Simocephalus sp.*); and

h. the results of a toxicity test for one (1) other North American freshwater aquatic species (other than a planktonic crustacean) that meets a minimum requirement of R 323.1057(2) of the Water Quality Standards. Examples of tests that would meet this requirement include a 96-hour LC_{50} for rainbow trout, bluegill, or fathead minnow.

7. Cold Shock Prevention

Cessation of thermal inputs to the receiving water by this facility shall occur gradually so as to avoid fish mortality due to cold shock during the winter months (November through March). The basis for this requirement is to allow fish associated with the discharge-heated mixing zone for Outfall 001 to acclimate to the decreasing temperature. The Department acknowledges that the permittee meets this condition based on the equipment and practices implemented at Outfall 001 identified in the application.

8. Intake Screen Backwash, Outfall 001

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge intake screen backwash from Outfall 001 to Lake Michigan. The permittee shall collect and remove debris accumulated on intake trash bars and dispose of such material on land in an appropriate manner.

9. Periodic/Temporary Rerouting of Combined Plant Discharge

The permittee is authorized to divert the combined flow from Units 1 & 2 and Unit 3 offshore intake structure under the following conditions: (a) for deicing when the intake water temperature falls below 36^{o} F and intakes are at risk of becoming partially or completely restricted because of icing, (b) when Unit 3 is off line during a scheduled or unscheduled outage and the deepwater discharge pumps are turned off, or (c) for thermal treatment or control of zebra mussels and asiatic clams. The permittee is not required to provide any additional monitoring of this discharge because the effluent limitations and monitoring requirements for Outfall 001, for which monitoring/reporting shall be continued as usual during the diversion, will determine compliance with the applicable water quality standards and any other requirements.

10. Cooling Water Intake Structures – Interim Approval

The federal rules promulgated by the United States Environmental Protection Agency (USEPA) in 40 CFR Parts 122 and 125 establishing the requirements of section 316(b) of the Clean Water Act for Existing Facilities took effect October 14, 2014. Beginning October 14, 2014, any facility covered by the rules requesting permit reissuance shall submit an application in accordance with the rules and shall be subject to the best technology available (BTA) standards for impingement mortality and entrainment as defined in the rules. In accordance with 40 CFR 125.95(a)(2), the Department approved the permittee's March 10, 2016, request for an alternate schedule for submission of the information required in 40 CFR 122.21(r). The alternate schedule for submission of the reports identified in the request for is set for April 30, 2018 (received).

The cooling water intake structure operated by the permittee has been evaluated using all available information relating to its location, design, construction, and capacity. At this time, the Department has made an **interim** determination that the cooling water intake structure represents BTA to minimize adverse environmental impact in accordance with section 316(b) of the federal Clean Water Act (33 U.S.C. section 1326). The permittee shall at all times properly operate and maintain the cooling water intake structure and associated equipment to minimize adverse environmental impact. The permittee shall give advance notice to the Department of any planned changes in the location, design, operation, or capacity of the intake structure. If the Department determines that additional technologies or control measures are necessary to reduce the impact of impingement or entrainment, the Department may revise the requirements of this condition. Nothing in this permit shall either be construed to relieve the permittee from civil or criminal penalties for previous or future fish losses, or authorize take for the purposes of a facility's compliance with the Endangered Species Act.

11. Facility Contact

The "Facility Contact" was specified in the application. The permittee may replace the facility contact at any time, and shall notify the Department in writing within 10 days after replacement (including the name, address and telephone number of the new facility contact).

a. The facility contact shall be (or a duly authorized representative of this person):
- for a corporation, a principal executive officer of at least the level of vice president; or a designated representative if the representative is responsible for the overall operation of the facility from which the discharge originates, as described in the permit application or other NPDES form,
- for a partnership, a general partner,
- for a sole proprietorship, the proprietor, or
- for a municipal, state, or other public facility, either a principal executive officer, the mayor, village president, city or village manager or other duly authorized employee.

b. A person is a duly authorized representative only if:
- the authorization is made in writing to the Department by a person described in paragraph a. of this section; and
- the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility (a duly authorized representative may thus be either a named individual or any individual occupying a named position).

Nothing in this section obviates the permittee from properly submitting reports and forms as required by law.

PART I

Section A. Limitations and Monitoring Requirements

12. Discharge Monitoring Report – Quality Assurance Study Program

The permittee shall participate in the Discharge Monitoring Report – Quality Assurance (DMR-QA) Study Program. The purpose of the DMR-QA Study Program is to annually evaluate the proficiency of all in-house and/or contract laboratory(ies) that perform, on behalf of the facility authorized to discharge under this permit, the analytical testing required under this permit. In accordance with Section 308 of the Clean Water Act (33 U.S.C. § 1318); and R 323.2138 and R 323.2154 of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, participation in the DMR-QA Study Program is required for all major facilities, and for minor facilities selected for participation by the Department.

Annually and in accordance with DMR-QA Study Program requirements and submittal due dates, the permittee shall submit to the Michigan DMR-QA Study Program state coordinator all documentation required by the DMR-QA Study. DMR-QA Study Program participation is required only for the analytes required under this permit and only when those analytes are also identified in the DMR-QA Study.

If the permitted facility's status as a major facility should change, participation in the DMR-QA Study Program may be reevaluated. Questions concerning participation in the DMR-QA Study Program should be directed to the Michigan DMR-QA Study Program state coordinator.

All forms and instructions required for participation in the DMR-QA Study Program, including submittal due dates and state coordinator contact information, can be found at http://www.epa.gov/compliance/discharge-monitoring-report-quality-assurance-study-program.

13. Schedule for Compliance for Bottom Ash Transport Water

The permittee shall manage the discharge of bottom ash transport water (BATW) to surface waters of the state in accordance with EPA's Final Steam Electric Reconsideration Rule (Final Rule), effective October 13, 2020. This schedule of compliance (SOC) is based on two separate compliance pathways established by the Final Rule for BATW: the Cessation of Coal Burning Activities subcategory and the installation of an effluent limitation guideline (ELG)-compliant technology to achieve up to a 90% reduction in BATW discharges to surface waters of the state. The Final Rule allows the permittee to transfer from the Cessation of Coal Burning Activities subcategory to other compliance options or subcategories allowed within the Final Rule without a permit modification if the permit contains conditions of both compliance pathways, and this SOC reflects that allowance.

The permittee shall attain compliance with the Final Rule by completing the following:

a. On or before October 13, 2021, the permittee shall:

1) submit a Notice of Planned Participation (NOPP) in the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19, if this compliance pathway is being considered, and/or

2) submit an update on the feasibility evaluation to select an ELG-compliant technology, if this compliance pathway is being considered.

b. On or before December 31, 2022, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory, if an NOPP was submitted in accordance with 1) above, and/or

2) submit a status report on the engineering and design process for the implementation of an ELG-compliant technology, if a feasibility evaluation update was submitted in accordance with 2) above.

c. On or before December 31, 2023, the permittee shall submit to the Department a report identifying the final compliance pathway selected for compliance with the Final Rule: either the Cessation of Coal Burning Activities subcategory (including the annual progress report in accordance with 40 CFR §423.19), or the implementation of an ELG-compliant technology.

d. On or before December 31, 2024, the permittee shall:

1) submit an annual progress report for the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19, or

2) submit a status report for the ongoing construction of, including any impediments to, final implementation of an ELG-compliant technology by December 31, 2025.

e. On or before December 31, 2025, the permittee shall:

1) submit an annual progress report for the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19, or

2) submit an initial certification statement regarding the operation of an ELG-compliant technology pursuant to 40 CFR §423.19 and comply with the requirements in Part I.A.14.b. of this permit.

f. If the permittee selected the Cessation of Coal Burning Activities subcategory as the final compliance pathway for meeting the requirements of the Final Rule, the permittee shall complete the following:

1) On or before December 31, 2026, the permittee shall submit an annual progress report for the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19.

2) On or before December 31, 2027, the permittee shall submit an annual progress report for the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19.

3) On or before December 31, 2028, the permittee shall comply with the requirements set forth in Part I.A.14.a. of this permit.

14. Bottom Ash Transport Water Discharge Prohibition

a. If the permittee selected the Cessation of Coal Burning Activities subcategory compliance pathway as set forth in Part I.A.13. of this permit, the discharge of BATW shall comply with the final effluent limitations set forth in this permit until no later than December 31, 2028, by which date the permittee shall cease discharge of BATW from any outfall.

b. If the permittee selected the ELG-compliant technology compliance pathway as set forth in Part I.A.13. of this permit and submitted to the Department an initial certification statement regarding the operation of an ELG-compliant technology, the Department may modify or reissue this permit in accordance with applicable laws and rules to include additional control requirements as necessary in accordance with 40 CFR §423.13(k). Beginning December 31, 2025, the permittee shall be limited to discharging newly generated BATW from any outfall in accordance with the requirements set forth in the in-effect permit.

PART I

Section B. Storm Water Pollution Prevention

1. Final Effluent Limitations and Monitoring Requirements

The permittee is authorized to discharge storm water associated with industrial activity, as defined under 40 CFR 122.26(b)(14)(i-ix), to the surface waters of the state. Such discharge shall be limited and monitored by the permittee as specified below.

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Visual Assessment of Storm Water Discharges
To ensure that storm water discharges from the facility do not violate the narrative standard in the receiving waters, storm water discharges shall be visually assessed in accordance with this permit.

c. Implementation of Storm Water Pollution Prevention Plan
The permittee shall implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) as required by this permit.

d. Certified Operator
The permittee shall have an Industrial Storm Water Certified Operator who has supervision over the facility's storm water treatment and control measures included in the SWPPP.

PART I

Section B. Storm Water Pollution Prevention

The Storm Water Pollution Prevention Plan (SWPPP) is a written procedure to reduce the exposure of storm water to significant materials and to reduce the amount of significant materials in the storm water discharge. An acceptable SWPPP shall identify potential sources of contamination and describe the controls necessary to reduce their impacts in accordance with Part I.B.2. through Part I.B.8. of this permit.

2. Source Identification

To identify potential sources of significant materials that can pollute storm water and subsequently be discharged from the facility, the SWPPP shall, at a minimum, include the following:

a. A site map identifying:

1) buildings and other permanent structures;

2) storage or disposal areas for significant materials;

3) secondary containment structures and descriptions of the significant materials contained within the primary containment structures;

4) storm water discharge points (which include outfalls and points of discharge), numbered or otherwise labeled for reference;

5) location of storm water and non-storm water inlets (numbered or otherwise labeled for reference) contributing to each discharge point;

6) location of NPDES-permitted discharges other than storm water;

7) outlines of the drainage areas contributing to each discharge point;

8) structural controls or storm water treatment facilities;

9) areas of vegetation (with brief descriptions such as lawn, old field, marsh, wooded, etc.);

10) areas of exposed and/or erodible soils and gravel lots;

11) impervious surfaces (e.g., roofs, asphalt, concrete, etc.);

12) name and location of receiving water(s); and

13) areas of known or suspected impacts on surface waters as designated under Part 201 (Environmental Response) of the NREPA.

b. A list of all significant materials that could pollute storm water. For each material listed, the SWPPP shall include each of the following descriptions:

1) the ways in which each type of significant material has been, or has reasonable potential to become, exposed to storm water (e.g., spillage during handling; leaks from pipes, pumps, and vessels; contact with storage piles, contaminated materials, or soils; waste handling and disposal; deposits from dust or overspray; etc.);

PART I

Section B. Storm Water Pollution Prevention

2) identification of the discharge point(s) and the inlet(s) contributing the significant material to each discharge point through which the significant material may be discharged if released; and

3) an evaluation of the reasonable potential for contribution of significant materials to storm water from at least the following areas or activities:

a) loading, unloading, and other significant material-handling operations;

b) outdoor storage, including secondary containment structures;

c) outdoor manufacturing or processing activities;

d) significant dust- or particulate-generating processes;

e) discharge from vents, stacks, and air emission controls;

f) on-site waste disposal practices;

g) maintenance and cleaning of vehicles, machines, and equipment;

h) areas of exposed and/or erodible soils;

i) Sites of Environmental Contamination listed under Part 201 (Environmental Response) of the NREPA;

j) areas of significant material residues;

k) areas where animals (wild or domestic) congregate and deposit wastes; and

l) other areas where storm water may come into contact with significant materials.

c. A listing of significant spills and significant leaks of polluting materials that occurred in areas that are exposed to precipitation or that discharge to a point source at the facility. The listing shall include spills that occurred over the three (3) years prior to the effective date of a permit authorizing discharge. The listing shall include the date, volume, and exact location of the release, and the action taken to clean up the material and/or prevent exposure to storm water or contamination of surface waters of the state. Any release that occurs after the SWPPP has been developed shall be controlled in accordance with the SWPPP and is cause for the SWPPP to be updated as appropriate <u>within 14 calendar days</u> of obtaining knowledge of the spill or loss.

d. A determination as to whether its facility discharges storm water to a water body for which an EPA-approved Total Maximum Daily Load (TMDL) has been established. If so, the permittee shall assess whether the TMDL requirements for the facility's discharge are being met through the existing SWPPP controls or whether additional control measures are necessary. The permitee's assessment of whether the TMDL requirements are being met shall focus on the effectiveness, adequacy, and implementation of the permitee's SWPPP controls.

e. A summary of existing storm water discharge sampling data (if available), describing pollutants in storm water discharges at the facility. This summary shall be accompanied by a description of the suspected source(s) of the pollutants detected.

PART I

Section B. Storm Water Pollution Prevention

3. Nonstructural Controls

To prevent significant materials from contacting storm water at the source, the SWPPP shall, at a minimum, include each of the following nonstructural controls:

a. Written procedures and a schedule for routine preventive maintenance. Preventive maintenance procedures shall describe routine inspections and maintenance of storm water management and control devices (e.g., cleaning of oil/water separators and catch basins, routine housekeeping activities, etc.), as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to the storm sewer system or the surface waters of the state. The routine inspection shall include areas of the facility in which significant materials have the reasonable potential to contaminate storm water. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

b. Written procedures and a schedule for good housekeeping to maintain a clean, orderly facility. Good housekeeping procedures shall include routine inspections that focus on the areas of the facility that have a reasonable potential to contaminate storm water entering the property. The routine housekeeping inspections may be combined with the routine inspections for the preventive maintenance program. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

c. Written procedures and a schedule for **quarterly** comprehensive site inspections, to be conducted by the Industrial Storm Water Certified Operator. At a minimum, one inspection shall be performed within each of the following quarters: January-March, April-June, July-September, and October-December. The comprehensive site inspections shall include, but not be limited to, inspection of structural controls in use at the facility, and the areas and equipment identified in the routine preventive maintenance and good housekeeping procedures. These inspections shall also include a review of the routine preventive maintenance reports, good housekeeping inspection reports, and any other paperwork associated with the SWPPP. The permittee may request Department approval of an alternate schedule for comprehensive site inspections. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below, and the following shall be included on the comprehensive inspection form/report:

    1) Date of the inspection.

    2) Name(s), title(s), and certification number(s) of the personnel conducting the inspection.

    3) Precipitation information (i.e., a description of recent rainfall/snowmelt events).

    4) All observations relating to the implementation of control measures. Items to include if applicable:

        a) updates on corrective actions implemented due to previously identified pollutant and/or discharge issues;

        b) any evidence of, or the potential for, pollutants to discharge to the drainage system or receiving waters and the condition of and around the discharge point including flow dissipation measures needing maintenance or repairs;

        c) any control measures needing maintenance or repairs; and

        d) any additional control measures needed to comply with permit requirements.

PART I

Section B. Storm Water Pollution Prevention

5) Any required revisions to the SWPPP resulting from the inspection.

6) A written certification stating the facility is in compliance with this permit and the SWPPP, or, if there are instances of noncompliance, they are identified.

7) Written procedures and a schedule for **quarterly** visual assessments of storm water discharges. At a minimum, one visual assessment shall be conducted within each of the following quarters: January-March, April-June, July-September, and October-December. These assessments shall be conducted as part of the comprehensive site inspection within one month of control measure observations made in accordance with 4), above. If the Department has approved an alternate schedule for the comprehensive site inspection, the visual assessment may likewise be conducted in accordance with the same approved alternate schedule.

The following are the requirements of the visual assessment. The permittee shall develop and clearly document, in writing, procedures for meeting these requirements:

a) Within six (6) months of the effective date of this permit, the permittee shall develop written procedures for conducting the visual assessment and incorporate these procedures into the SWPPP. If Qualified Personnel rather than an Industrial Storm Water Certified Operator will collect storm water samples, these procedures shall include a written description of the training given to these personnel to qualify them to collect the samples, as well as documentation verifying that these personnel have received this training. The first visual assessment shall be conducted in conjunction with the next occurring comprehensive inspection. If changes resulting in altered drainage patterns occur at the facility, the permittee shall modify the procedures for conducting the visual assessment in accordance with the requirements of Keeping SWPPPs Current, below, and these modifications shall be incorporated into the SWPPP prior to conducting the next visual assessment.

b) A visual assessment shall be conducted of a representative storm water **sample** collected **from each storm water discharge point**. Storm water samples shall be visually assessed for conditions that could cause a violation of water quality standards as defined in Water Quality Standards, below. The visual assessment shall be made of the storm water sample in a clean, clear glass or plastic container. Only an Industrial Storm Water Certified Operator shall conduct this visual assessment. Visual assessment of the storm water sample shall be conducted within 48 hours of sample collection.

   Representative storm water samples shall be collected:

   (1) from each storm water discharge point identified as set forth under Source Identification, above. These samples may be collected by one or more of the following: an Industrial Storm Water Certified Operator; and/or an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the sample ("Qualified Personnel"); and/or an automated sampling device; and

   (2) within the first 30 minutes of the start of a discharge from a storm event and on discharges that occur at least 72 hours (3 days) from the previous discharge. If it is not possible to collect the sample within the first 30 minutes of discharge, the sample shall be collected as soon thereafter as practicable, but not exceeding 60 minutes. In the case of snowmelt, samples shall be collected during a period with measurable discharge from the site.

PART I

Section B. Storm Water Pollution Prevention

c) A visual assessment shall be conducted of the storm water **discharge at each storm water discharge point**. (If an automated sampling device is used to collect the storm water sample, this requirement is waived). Either an Industrial Storm Water Certified Operator and/or Qualified Personnel may conduct this visual assessment. This visual assessment may be conducted directly – by someone physically present at the storm water discharge at each storm water discharge point; or it may be conducted indirectly – through the use of a visual recording taken of the storm water discharge at each storm water discharge point. Direct visual assessment shall be conducted at the same time that the storm water sample is collected. Indirect visual assessment shall be conducted using a visual recording taken of the storm water discharge at the same time that the storm water sample was collected.

d) Visual assessments shall be documented. This documentation shall be retained in accordance with Record Keeping, below, and shall include the following:

(1) sampling location(s) at the storm water discharge point(s) identified on the site map (see Source Identification, above);

(2) storm event information (i.e., length of event expressed in hours, approximate size of event expressed in inches of precipitation, duration of time since previous event that caused a discharge, and date and time the discharge began);

(3) date and time of the visual assessment of each storm water **discharge** at each storm water discharge point;

(4) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who conducted the visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(5) observations made during visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(6) if applicable, any visual recordings used to conduct the visual assessment of the storm water **discharge** at each storm water discharge point;

(7) date and time of sample collection for each storm water **sample**;

(8) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who collected the storm water **sample**. If an automated sampling device was used to collect the storm water sample, the permittee shall document that, instead;

(9) date and time of the visual assessment of each storm water **sample**;

(10) name(s), title(s), and operator number(s) of the Industrial Storm Water Certified Operator(s) who conducted the visual assessment of each storm water **sample**;

(11) observations made during visual assessment of each storm water **sample**;

PART I

Section B. Storm Water Pollution Prevention

(12) full-color photographic evidence of the storm water **sample** against a white background;

(13) nature of the discharge (i.e., rainfall or snowmelt);

(14) probable sources of any observed storm water contamination; and

(15) if applicable, an explanation for why it was not possible to collect samples within the first 30 minutes of discharge.

e) When adverse weather conditions prevent a visual assessment during the quarter, a substitute visual assessment shall be conducted during the next qualifying storm event. Documentation of the rationale for no visual assessment during a quarter shall be included with the SWPPP records as described in Record Keeping, below. Adverse conditions are those that are dangerous or create inaccessibility for personnel, such as local flooding, high winds, electrical storms, or situations that otherwise make sampling impractical such as drought or extended frozen conditions.

f) If the facility has two (2) or more discharge points that are believed to discharge substantially identical storm water effluents, the facility may conduct visual assessments of the discharge at just one (1) of the discharge points and report that the results also apply to the other substantially identical discharge point(s). The determination of substantially identical discharge points is to be based on the significant material evaluation conducted as set forth under Source Identification, above, and shall be clearly documented in the SWPPP. Visual assessments shall be conducted on a rotating basis of each substantially identical discharge point throughout the period of coverage under this permit.

d. A description of material handling procedures and storage requirements for significant materials. Equipment and procedures for cleaning up spills shall be identified in the SWPPP and made available to the appropriate personnel. The procedures shall identify measures to prevent spilled materials or material residues from contaminating storm water entering the property. The SWPPP shall include language describing what a reportable spill or release is and the appropriate reporting requirements in accordance with Part II.C.6. and Part II.C.7. The SWPPP may include, by reference, requirements of either a Pollution Incident Prevention Plan (PIPP) prepared in accordance with the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); a Hazardous Waste Contingency Plan prepared in accordance with 40 CFR 264 and 265 Subpart D, as required by Part 111 of the NREPA; or a Spill Prevention Control and Countermeasure (SPCC) plan prepared in accordance with 40 CFR 112.

e. Identification of areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. Gravel lots shall be included. The SWPPP shall also identify measures used to control soil erosion and sedimentation.

f. A description of the employee training program that will be implemented on an annual basis to inform appropriate personnel at all levels of their responsibility as it relates to the components and goals of the SWPPP. The SWPPP shall identify periodic dates for the employee training program. Records of the employee training program shall be retained in accordance with Record Keeping, below.

g. Identification of actions to limit the discharge of significant materials in order to comply with TMDL requirements, if applicable.

PART I

Section B. Storm Water Pollution Prevention

h. Identification of significant materials expected to be present in storm water discharges following implementation of nonstructural preventive measures and source controls.

4. Structural Controls

Where implementation of the measures required by Nonstructural Controls, above, does not control storm water discharges in accordance with Water Quality Standards, below, the SWPPP shall provide a description of the location, function, design criteria, and installation/construction schedule of structural controls for prevention and treatment. Structural controls may be necessary:

a. to prevent uncontaminated storm water from contacting, or being contacted by, significant materials; or

b. if preventive measures are not feasible or are inadequate to keep significant materials at the site from contaminating storm water. Structural controls shall be used to treat, divert, isolate, recycle, reuse, or otherwise manage storm water in a manner that reduces the level of significant materials in the storm water and provides compliance with water quality standards as identified in Water Quality Standards, below.

5. Keeping SWPPPs Current

a. The permittee and/or the Industrial Storm Water Certified Operator shall review the SWPPP annually after it is developed and maintain a written report of the review in accordance with Record Keeping, below. Based on the review, the permittee or the Industrial Storm Water Certified Operator shall amend the SWPPP as needed to ensure continued compliance with the terms and conditions of this permit. The written report shall be submitted to the Department on or before January 10^{th} of each year.

b. The SWPPP developed under the conditions of a previous permit shall be amended as necessary to ensure compliance with this permit.

c. The SWPPP shall be updated or amended whenever changes at the facility have the potential to increase the exposure of significant materials to storm water, significant spills occur at the facility, or when the SWPPP is determined by the permittee or the Department to be ineffective in achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Updates based on increased activity or spills at the facility shall include a description of how the permittee intends to control any new sources of significant materials, or respond to and prevent spills in accordance with the requirements of this permit (see Source Identification; Nonstructural Controls; and Structural Controls, above).

d. The Department may notify the permittee at any time that the SWPPP does not meet minimum requirements of this permit. Such notification shall identify why the SWPPP does not meet minimum requirements of this permit. The permittee shall make the required changes to the SWPPP within 30 days after such notification from the Department or authorized representative and shall submit to the Department a written certification that the requested changes have been made.

e. Amendments to the SWPPP shall be signed and retained on-site with the SWPPP pursuant to Signature and SWPPP Review, below.

PART I

Section B. Storm Water Pollution Prevention

6. Industrial Storm Water Certified Operator Update

If the Industrial Storm Water Certified Operator is changed or an Industrial Storm Water Certified Operator is added, the permittee shall provide the name and certification number of the new Industrial Storm Water Certified Operator to the Department. If a facility has multiple Industrial Storm Water Certified Operators, the names and certification numbers of all shall be included in the SWPPP.

7. Signature and SWPPP Review

a. The SWPPP shall be reviewed and signed by the Industrial Storm Water Certified Operator(s) and by either the permittee or an authorized representative in accordance with 40 CFR 122.22. The SWPPP and associated records shall be retained on-site at the facility that generates the storm water discharge.

b. The permittee shall make the SWPPP, reports, log books, storm water discharge sampling data (if collected), and items required by Record Keeping, below, available upon request to the Department. The Department makes the non-confidential business portions of the SWPPP available to the public.

8. Record Keeping

The permittee shall maintain records of all SWPPP-related inspection and maintenance activities. Records shall also be kept describing incidents such as spills or other discharges that can affect the quality of storm water. All such records shall be retained for three (3) years. The following records are required by this permit (see Nonstructural Controls; and Keeping SWPPPs Current, above):

a. routine preventive maintenance inspection reports;

b. routine good housekeeping inspection reports;

c. comprehensive site inspection reports;

d. documentation of visual assessments;

e. employee training records; and

f. written summaries of the annual SWPPP review.

PART I

Section B. Storm Water Pollution Prevention

9. Water Quality Standards

At the time of discharge, there shall be no violation of water quality standards in the receiving waters as a result of the storm water discharge. This requirement includes, but is not limited to, the following conditions:

a. In accordance with R 323.1050 of the Part 4 Rules promulgated pursuant to Part 31 of the NREPA, the receiving waters shall not have any of the following unnatural physical properties as a result of this discharge in quantities which are, or may become, injurious to any designated use: turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits.

b. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department, followed by a written report within five (5) days detailing the findings of the investigation and the steps taken to correct the condition.

c. Any pollutant for which a level of control is specified to meet a TMDL established by the Department shall be controlled at the facility so that its discharge is reduced by/to the amount specified in the TMDL.

PART I

Section B. Storm Water Pollution Prevention

10. Prohibition of Non-Storm Water Discharges

Discharges of material other than storm water shall be in compliance with an NPDES permit issued for the discharge. Storm water shall be defined to include all of the following non-storm water discharges, provided pollution prevention controls for the non-storm water component are identified in the SWPPP:

a. discharges from fire hydrant flushing;

b. potable water sources, including water line flushing;

c. water from fire system testing and fire-fighting training without burned materials or chemical fire suppressants;

d. irrigation drainage;

e. lawn watering;

f. routine building wash-down that does not use detergents or other compounds;

g. pavement wash waters where contamination by toxic or hazardous materials has not occurred (unless all contamination by toxic or hazardous materials has been removed) and where detergents are not used;

h. uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;

i. springs;

j. uncontaminated groundwater;

k. foundation or footing drains where flows are not contaminated with process materials such as solvents; and

l. discharges from fire-fighting activities. Discharges from fire-fighting activities are exempted from the requirement to be identified in the SWPPP.

11. Tracer Dye Discharges

This permit does not authorize the discharge of tracer dyes without approval from the Department. Requests to discharge tracer dyes shall be submitted to the Department in accordance with Rule 1097 (R 323.1097 of the Michigan Administrative Code).

PART II

Part II may include terms and /or conditions not applicable to discharges covered under this permit.

Section A. Definitions

Acute toxic unit (TU_A) means $100/LC_{50}$ where the LC_{50} is determined from a whole effluent toxicity (WET) test which produces a result that is statistically or graphically estimated to be lethal to 50% of the test organisms.

Annual monitoring frequency refers to a calendar year beginning on January 1 and ending on December 31. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Authorized public agency means a state, local, or county agency that is designated pursuant to the provisions of section 9110 of Part 91 of the NREPA to implement soil erosion and sedimentation control requirements with regard to construction activities undertaken by that agency.

Best management practices (BMPs) means structural devices or nonstructural practices that are designed to prevent pollutants from entering into storm water, to direct the flow of storm water, or to treat polluted storm water.

Bioaccumulative chemical of concern (BCC) means a chemical which, upon entering the surface waters, by itself or as its toxic transformation product, accumulates in aquatic organisms by a human health bioaccumulation factor of more than 1000 after considering metabolism and other physiochemical properties that might enhance or inhibit bioaccumulation. The human health bioaccumulation factor shall be derived according to R 323.1057(5). Chemicals with half-lives of less than 8 weeks in the water column, sediment, and biota are not BCCs. The minimum bioaccumulation concentration factor (BAF) information needed to define an organic chemical as a BCC is either a field-measured BAF or a BAF derived using the biota-sediment accumulation factor (BSAF) methodology. The minimum BAF information needed to define an inorganic chemical as a BCC, including an organometal, is either a field-measured BAF or a laboratory-measured bioconcentration factor (BCF). The BCCs to which these rules apply are identified in Table 5 of R 323.1057 of the Water Quality Standards.

Biosolids are the solid, semisolid, or liquid residues generated during the treatment of sanitary sewage or domestic sewage in a treatment works. This includes, but is not limited to, scum or solids removed in primary, secondary, or advanced wastewater treatment processes and a derivative of the removed scum or solids.

Bulk biosolids means biosolids that are not sold or given away in a bag or other container for application to a lawn or home garden.

Certificate of Coverage (COC) is a document, issued by the Department, which authorizes a discharge under a general permit.

Chronic toxic unit (TU_C) means 100/MATC or $100/IC_{25}$, where the maximum acceptable toxicant concentration (MATC) and IC_{25} are expressed as a percent effluent in the test medium.

Class B biosolids refers to material that has met the Class B pathogen reduction requirements or equivalent treatment by a Process to Significantly Reduce Pathogens (PSRP) in accordance with the Part 24 Rules. Processes include aerobic digestion, composting, anaerobic digestion, lime stabilization and air drying.

Combined sewer system is a sewer system in which storm water runoff is combined with sanitary wastes.

PART II

Section A. Definitions

Daily concentration is the sum of the concentrations of the individual samples of a parameter divided by the number of samples taken during any calendar day. If the parameter concentration in any sample is less than the quantification limit, regard that value as zero when calculating the daily concentration. The daily concentration will be used to determine compliance with any maximum and minimum daily concentration limitations (except for pH and dissolved oxygen). When required by the permit, report the maximum calculated daily concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the Discharge Monitoring Reports (DMRs).

For pH, report the maximum value of any *individual* sample taken during the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs and the minimum value of any *individual* sample taken during the month in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. For dissolved oxygen, report the minimum concentration of any *individual* sample in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Daily loading is the total discharge by weight of a parameter discharged during any calendar day. This value is calculated by multiplying the daily concentration by the total daily flow and by the appropriate conversion factor. The daily loading will be used to determine compliance with any maximum daily loading limitations. When required by the permit, report the maximum calculated daily loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMRs.

Daily monitoring frequency refers to a 24-hour day. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Department means the Michigan Department of Environmental Quality.

Detection level means the lowest concentration or amount of the target analyte that can be determined to be different from zero by a single measurement at a stated level of probability.

Discharge means the addition of any waste, waste effluent, wastewater, pollutant, or any combination thereof to any surface water of the state.

EC_{50} means a statistically or graphically estimated concentration that is expected to cause 1 or more specified effects in 50% of a group of organisms under specified conditions.

Fecal coliform bacteria monthly
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a discharge event. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR. If the period in which the discharge event occurred was partially in each of two months, the calculated monthly value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a reporting month. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

PART II

Section A. Definitions

Fecal coliform bacteria 7-day
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days of discharge during a discharge event. If the number of daily concentrations determined during the discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean value for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. If the 7-day period was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days in a reporting month. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMRs. The first calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

Flow-proportioned sample is a composite sample with the sample volume proportional to the effluent flow.

General permit means a National Pollutant Discharge Elimination System permit issued authorizing a category of similar discharges.

Geometric mean is the average of the logarithmic values of a base 10 data set, converted back to a base 10 number.

Grab sample is a single sample taken at neither a set time nor flow.

IC_{25} means the toxicant concentration that would cause a 25% reduction in a nonquantal biological measurement for the test population.

Illicit connection means a physical connection to a municipal separate storm sewer system that primarily conveys non-storm water discharges other than uncontaminated groundwater into the storm sewer; or a physical connection not authorized or permitted by the local authority, where a local authority requires authorization or a permit for physical connections.

Illicit discharge means any discharge to, or seepage into, a municipal separate storm sewer system that is not composed entirely of storm water or uncontaminated groundwater. Illicit discharges include non-storm water discharges through pipes or other physical connections; dumping of motor vehicle fluids, household hazardous wastes, domestic animal wastes, or litter; collection and intentional dumping of grass clippings or leaf litter; or unauthorized discharges of sewage, industrial waste, restaurant wastes, or any other non-storm water waste directly into a separate storm sewer.

Individual permit means a site-specific NPDES permit.

Inlet means a catch basin, roof drain, conduit, drain tile, retention pond riser pipe, sump pump, or other point where storm water or wastewater enters into a closed conveyance system prior to discharge off site or into waters of the state.

PART II

Section A. Definitions

Interference is a discharge which, alone or in conjunction with a discharge or discharges from other sources, both: 1) inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and 2) therefore, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or, of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent state or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including Title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including state regulations contained in any state sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act. [This definition does not apply to sample matrix interference].

Land application means spraying or spreading biosolids or a biosolids derivative onto the land surface, injecting below the land surface, or incorporating into the soil so that the biosolids or biosolids derivative can either condition the soil or fertilize crops or vegetation grown in the soil.

LC_{50} means a statistically or graphically estimated concentration that is expected to be lethal to 50% of a group of organisms under specified conditions.

Maximum acceptable toxicant concentration (MATC) means the concentration obtained by calculating the geometric mean of the lower and upper chronic limits from a chronic test. A lower chronic limit is the highest tested concentration that did not cause the occurrence of a specific adverse effect. An upper chronic limit is the lowest tested concentration which did cause the occurrence of a specific adverse effect and above which all tested concentrations caused such an occurrence.

Maximum extent practicable means implementation of best management practices by a public body to comply with an approved storm water management program as required by a national permit for a municipal separate storm sewer system, in a manner that is environmentally beneficial, technically feasible, and within the public body’s legal authority.

MGD means million gallons per day.

Monthly concentration is the sum of the daily concentrations determined during a reporting period divided by the number of daily concentrations determined. The calculated monthly concentration will be used to determine compliance with any maximum monthly concentration limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly concentration in the “AVERAGE” column under “QUALITY OR CONCENTRATION” on the DMR.

For minimum percent removal requirements, the monthly influent concentration and the monthly effluent concentration shall be determined. The calculated monthly percent removal, which is equal to 100 times the quantity [1 minus the quantity (monthly effluent concentration divided by the monthly influent concentration)], shall be reported in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Monthly loading is the sum of the daily loadings of a parameter divided by the number of daily loadings determined during a reporting period. The calculated monthly loading will be used to determine compliance with any maximum monthly loading limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly loading in the “AVERAGE” column under “QUANTITY OR LOADING” on the DMR.

Monthly monitoring frequency refers to a calendar month. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

PART II

Section A. Definitions

Municipal separate storm sewer means a conveyance or system of conveyances designed or used for collecting or conveying storm water which is not a combined sewer and which is not part of a publicly-owned treatment works as defined in the Code of Federal Regulations at 40 CFR 122.2.
Municipal separate storm sewer system (MS4) means all separate storm sewers that are owned or operated by the United States, a state, city, village, township, county, district, association, or other public body created by or pursuant to state law, having jurisdiction over disposal of sewage, industrial wastes, storm water, or other wastes, including special districts under state law, such as a sewer district, flood control district, or drainage district, or similar entity, or a designated or approved management agency under Section 208 of the Federal Act that discharges to the waters of the state. This term includes systems similar to separate storm sewer systems in municipalities, such as systems at military bases, large hospital or prison complexes, and highways and other thoroughfares. The term does not include separate storm sewers in very discrete areas, such as individual buildings.

National Pretreatment Standards are the regulations promulgated by or to be promulgated by the Federal Environmental Protection Agency pursuant to Section 307(b) and (c) of the Federal Act. The standards establish nationwide limits for specific industrial categories for discharge to a POTW.

No observed adverse effect level (NOAEL) means the highest tested dose or concentration of a substance which results in no observed adverse effect in exposed test organisms where higher doses or concentrations result in an adverse effect.

Noncontact cooling water is water used for cooling which does not come into direct contact with any raw material, intermediate product, by-product, waste product or finished product.

Nondomestic user is any discharger to a POTW that discharges wastes other than or in addition to water-carried wastes from toilet, kitchen, laundry, bathing or other facilities used for household purposes.

Outfall is the location at which a point source discharge enters the surface waters of the state.

Part 91 agency means an agency that is designated by a county board of commissioners pursuant to the provisions of section 9105 of Part 91 of the NREPA; an agency that is designated by a city, village, or township in accordance with the provisions of section 9106 of Part 91 of the NREPA; or the Department for soil erosion and sedimentation activities under Part 615, Part 631, or Part 632 pursuant to the provisions of section 9115 of Part 91 of the NREPA.

Part 91 permit means a soil erosion and sedimentation control permit issued by a Part 91 agency pursuant to the provisions of Part 91 of the NREPA.

Partially treated sewage is any sewage, sewage and storm water, or sewage and wastewater, from domestic or industrial sources that is treated to a level less than that required by the permittee's National Pollutant Discharge Elimination System permit, or that is not treated to national secondary treatment standards for wastewater, including discharges to surface waters from retention treatment facilities.

Point of discharge is the location of a point source discharge where storm water is discharged directly into a separate storm sewer system.

Point source discharge means a discharge from any discernible, confined, discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, or rolling stock. Changing the surface of land or establishing grading patterns on land will result in a point source discharge where the runoff from the site is ultimately discharged to waters of the state.

Polluting material means any material, in solid or liquid form, identified as a polluting material under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

PART II

Section A. Definitions

POTW is a publicly owned treatment work.

Pretreatment is reducing the amount of pollutants, eliminating pollutants, or altering the nature of pollutant properties to a less harmful state prior to discharge into a public sewer. The reduction or alteration can be by physical, chemical, or biological processes, process changes, or by other means. Dilution is not considered pretreatment unless expressly authorized by an applicable National Pretreatment Standard for a particular industrial category.
Public (as used in the MS4 individual permit) means all persons who potentially could affect the authorized storm water discharges, including, but not limited to, residents, visitors to the area, public employees, businesses, industries, and construction contractors and developers.

Public body means the United States; the state of Michigan; a city, village, township, county, school district, public college or university, or single-purpose governmental agency; or any other body which is created by federal or state statute or law.

Qualified Personnel means an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the storm water sample.

Qualifying storm event means a storm event causing greater than 0.1 inch of rainfall and occurring at least 72 hours after the previous measurable storm event that also caused greater than 0.1 inch of rainfall. Upon request, the Department may approve an alternate definition meeting the condition of a qualifying storm event.

Quantification level means the measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calculated at a specified concentration above the detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant.

Quarterly monitoring frequency refers to a three month period, defined as January through March, April through June, July through September, and October through December. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Regional Administrator is the Region 5 Administrator, U.S. EPA, located at R-19J, 77 W. Jackson Blvd., Chicago, Illinois 60604.

Regulated area means the permittee's urbanized area, where urbanized area is defined as a place and its adjacent densely-populated territory that together have a minimum population of 50,000 people as defined by the United States Bureau of the Census and as determined by the latest available decennial census.

Secondary containment structure means a unit, other than the primary container, in which significant materials are packaged or held, which is required by State or Federal law to prevent the escape of significant materials by gravity into sewers, drains, or otherwise directly or indirectly into any sewer system or to the surface or ground waters of this state.

Separate storm sewer system means a system of drainage, including, but not limited to, roads, catch basins, curbs, gutters, parking lots, ditches, conduits, pumping devices, or man-made channels, which is not a combined sewer where storm water mixes with sanitary wastes, and is not part of a POTW.

Significant industrial user is a nondomestic user that: 1) is subject to Categorical Pretreatment Standards under 40 CFR 403.6 and 40 CFR Chapter I, Subchapter N; or 2) discharges an average of 25,000 gallons per day or more of process wastewater to a POTW (excluding sanitary, noncontact cooling and boiler blowdown wastewater); contributes a process waste stream which makes up five (5) percent or more of the average dry weather hydraulic or organic capacity of the POTW treatment plant; or is designated as such by the permittee as defined in 40 CFR 403.12(a) on the basis that the industrial user has a reasonable potential for adversely

PART II

Section A. Definitions

affecting the POTW's treatment plant operation or violating any pretreatment standard or requirement (in accordance with 40 CFR 403.8(f)(6)).

Significant materials Significant Materials means any material which could degrade or impair water quality, including but not limited to: raw materials; fuels; solvents, detergents, and plastic pellets; finished materials such as metallic products; hazardous substances designated under Section 101(14) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (see 40 CFR 372.65); any chemical the facility is required to report pursuant to Section 313 of Emergency Planning and Community Right-to-Know Act (EPCRA); polluting materials as identified under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); Hazardous Wastes as defined in Part 111 of the NREPA; fertilizers; pesticides; and waste products such as ashes, slag, and sludge that have the potential to be released with storm water discharges.

Significant spills and significant leaks means any release of a polluting material reportable under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

Special-use area means secondary containment structures required by state or federal law; lands on Michigan's List of Sites of Environmental Contamination pursuant to Part 201, Environmental Remediation, of the NREPA; and/or areas with other activities that may contribute pollutants to the storm water for which the Department determines monitoring is needed.

Stoichiometric means the quantity of a reagent calculated to be necessary and sufficient for a given chemical reaction.

Storm water means storm water runoff, snow melt runoff, surface runoff and drainage, and non-storm water included under the conditions of this permit.

Storm water discharge point is the location where the point source discharge of storm water is directed to surface waters of the state or to a separate storm sewer. It includes the location of all point source discharges where storm water exits the facility, including *outfalls* which discharge directly to surface waters of the state, and *points of discharge* which discharge directly into separate storm sewer systems.

SWPPP means the Storm Water Pollution Prevention Plan prepared in accordance with this permit.

Tier I value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier I toxicity database.

Tier II value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier II toxicity database.

Total maximum daily loads (TMDLs) are required by the Federal Act for waterbodies that do not meet water quality standards. TMDLs represent the maximum daily load of a pollutant that a waterbody can assimilate and meet water quality standards, and an allocation of that load among point sources, nonpoint sources, and a margin of safety.

Toxicity reduction evaluation (TRE) means a site-specific study conducted in a stepwise process designed to identify the causative agents of effluent toxicity, isolate the sources of toxicity, evaluate the effectiveness of toxicity control options, and then confirm the reduction in effluent toxicity.

Water Quality Standards means the Part 4 Water Quality Standards promulgated pursuant to Part 31 of the NREPA, being R 323.1041 through R 323.1117 of the Michigan Administrative Code.

PART II

Section A. Definitions

Weekly monitoring frequency refers to a calendar week which begins on Sunday and ends on Saturday. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

WWSL is a wastewater stabilization lagoon.

WWSL discharge event is a discrete occurrence during which effluent is discharged to the surface water up to 10 days of a consecutive 14 day period.

3-portion composite sample is a sample consisting of three equal-volume grab samples collected at equal intervals over an 8-hour period.

7-day concentration
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily concentrations determined. If the number of daily concentrations determined during the WWSL discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations. When required by the permit, report the maximum calculated 7-day concentration for the WWSL discharge event in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days in a reporting month divided by the number of daily concentrations determined. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations in the reporting month. When required by the permit, report the maximum calculated 7-day concentration for the month in the “MAXIMUM” column under “QUALITY OR CONCENTRATION” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

PART II

Section A. Definitions

7-day loading
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily loadings determined. If the number of daily loadings determined during the WWSL discharge event is less than 7 days, the number of actual daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations. When required by the permit, report the maximum calculated 7-day loading for the WWSL discharge event in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred

FOR ALL OTHER DISCHARGES – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days in a reporting month divided by the number of daily loadings determined. If the number of daily loadings determined is less than 7, the actual number of daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations in the reporting month. When required by the permit, report the maximum calculated 7-day loading for the month in the “MAXIMUM” column under “QUANTITY OR LOADING” on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

24-hour composite sample is a flow-proportioned composite sample consisting of hourly or more frequent portions that are taken over a 24-hour period. A time-proportioned composite sample may be used upon approval of the Department if the permittee demonstrates it is representative of the discharge.

PART II

Section B. Monitoring Procedures

1. Representative Samples

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Test Procedures

Test procedures for the analysis of pollutants shall conform to regulations promulgated pursuant to Section 304(h) of the Federal Act (40 CFR Part 136 – Guidelines Establishing Test Procedures for the Analysis of Pollutants), unless specified otherwise in this permit. **Test procedures used shall be sufficiently sensitive to determine compliance with applicable effluent limitations**. Requests to use test procedures not promulgated under 40 CFR Part 136 for pollutant monitoring required by this permit shall be made in accordance with the Alternate Test Procedures regulations specified in 40 CFR 136.4. These requests shall be submitted to the Section Manager of the Permits Section, Water Resources Division, Michigan Department of Environmental Quality, P.O. Box 30458, Lansing, Michigan, 48909-7958. The permittee may use such procedures upon approval.

The permittee shall periodically calibrate and perform maintenance procedures on all analytical instrumentation at intervals to ensure accuracy of measurements. The calibration and maintenance shall be performed as part of the permittee's laboratory Quality Control/Quality Assurance program.

3. Instrumentation

The permittee shall periodically calibrate and perform maintenance procedures on all monitoring instrumentation at intervals to ensure accuracy of measurements.

4. Recording Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information: 1) the exact place, date, and time of measurement or sampling; 2) the person(s) who performed the measurement or sample collection; 3) the dates the analyses were performed; 4) the person(s) who performed the analyses; 5) the analytical techniques or methods used; 6) the date of and person responsible for equipment calibration; and 7) the results of all required analyses.

5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, or longer if requested by the Regional Administrator or the Department.

PART II

Section C. Reporting Requirements

1. Start-up Notification

If the permittee will not discharge during the first 60 days following the effective date of this permit, the permittee shall notify the Department within 14 days following the effective date of this permit, and then 60 days prior to the commencement of the discharge.

2. Submittal Requirements for Self-Monitoring Data

Part 31 of the NREPA (specifically Section 324.3110(7)); and R 323.2155(2) of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, allow the Department to specify the forms to be utilized for reporting the required self-monitoring data. Unless instructed on the effluent limitations page to conduct "Retained Self-Monitoring," the permittee shall submit self-monitoring data via the Department's MiWaters system.

The permittee shall utilize the information provided on the MiWaters website, located at https://miwaters.deq.state.mi.us, to access and submit the electronic forms. Both monthly summary and daily data shall be submitted to the Department no later than the 20th day of the month following each month of the authorized discharge period(s). The permittee may be allowed to submit the electronic forms after this date if the Department has granted an extension to the submittal date.

3. Retained Self-Monitoring Requirements

If instructed on the effluent limits page (or otherwise authorized by the Department in accordance with the provisions of this permit) to conduct retained self-monitoring, the permittee shall maintain a year-to-date log of retained self-monitoring results and, upon request, provide such log for inspection to the staff of the Department. Retained self-monitoring results are public information and shall be promptly provided to the public upon request.

The permittee shall certify, in writing, to the Department, on or before January 10th (April 1st for animal feeding operation facilities) of each year, that: 1) all retained self-monitoring requirements have been complied with and a year-to-date log has been maintained; and 2) the application on which this permit is based still accurately describes the discharge. With this annual certification, the permittee shall submit a summary of the previous year's monitoring data. The summary shall include maximum values for samples to be reported as daily maximums and/or monthly maximums and minimum values for any daily minimum samples.

Retained self-monitoring may be denied to a permittee by notification in writing from the Department. In such cases, the permittee shall submit self-monitoring data in accordance with Part II.C.2., above. Such a denial may be rescinded by the Department upon written notification to the permittee. Reissuance or modification of this permit or reissuance or modification of an individual permittee's authorization to discharge shall not affect previous approval or denial for retained self-monitoring unless the Department provides notification in writing to the permittee.

4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

PART II

Section C. Reporting Requirements

Monitoring required pursuant to Part 41 of the NREPA or Rule 35 of the Mobile Home Park Commission Act (Act 96 of the Public Acts of 1987) for assurance of proper facility operation shall be submitted as required by the Department.

5. Compliance Dates Notification

Within 14 days of every compliance date specified in this permit, the permittee shall submit a *written* notification to the Department indicating whether or not the particular requirement was accomplished. If the requirement was not accomplished, the notification shall include an explanation of the failure to accomplish the requirement, actions taken or planned by the permittee to correct the situation, and an estimate of when the requirement will be accomplished. If a written report is required to be submitted by a specified date and the permittee accomplishes this, a separate written notification is not required.

6. Noncompliance Notification

Compliance with all applicable requirements set forth in the Federal Act, Parts 31 and 41 of the NREPA, and related regulations and rules is required. All instances of noncompliance shall be reported as follows:

a. 24-Hour Reporting
Any noncompliance which may endanger health or the environment (including maximum and/or minimum daily concentration discharge limitation exceedances) shall be reported, verbally, within 24 hours from the time the permittee becomes aware of the noncompliance. A written submission shall also be provided within five (5) days.

b. Other Reporting
The permittee shall report, in writing, all other instances of noncompliance not described in a. above at the time monitoring reports are submitted; or, in the case of retained self-monitoring, within five (5) days from the time the permittee becomes aware of the noncompliance.

Written reporting shall include: 1) a description of the discharge and cause of noncompliance; and 2) the period of noncompliance, including exact dates and times, or, if not yet corrected, the anticipated time the noncompliance is expected to continue, and the steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

7. Spill Notification

The permittee shall immediately report any release of any polluting material which occurs to the surface waters or groundwaters of the state, unless the permittee has determined that the release is not in excess of the threshold reporting quantities specified in the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code), by calling the Department at the number indicated on the second page of this permit (or, if this is a general permit, on the COC); or, if the notice is provided after regular working hours, call the Department's 24-hour Pollution Emergency Alerting System telephone number, 1-800-292-4706 (calls from **out-of-state** dial 1-517-373-7660).

Within ten (10) days of the release, the permittee shall submit to the Department a full written explanation as to the cause of the release, the discovery of the release, response (clean-up and/or recovery) measures taken, and preventive measures taken or a schedule for completion of measures to be taken to prevent reoccurrence of similar releases.

PART II

Section C. Reporting Requirements

8. Upset Noncompliance Notification

If a process "upset" (defined as an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee) has occurred, the permittee who wishes to establish the affirmative defense of upset, shall notify the Department by telephone within 24 hours of becoming aware of such conditions; and within five (5) days, provide in writing, the following information:

a. that an upset occurred and that the permittee can identify the specific cause(s) of the upset;

b. that the permitted wastewater treatment facility was, at the time, being properly operated and maintained (note that an upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation); and

c. that the permittee has specified and taken action on all responsible steps to minimize or correct any adverse impact in the environment resulting from noncompliance with this permit.

No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

In any enforcement proceedings, the permittee, seeking to establish the occurrence of an upset, has the burden of proof.

9. Bypass Prohibition and Notification

a. Bypass Prohibition
Bypass is prohibited, and the Department may take an enforcement action, unless:

1) bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

2) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass; and

3) the permittee submitted notices as required under 9.b. or 9.c. below.

b. Notice of Anticipated Bypass
If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least ten (10) days before the date of the bypass, and provide information about the anticipated bypass as required by the Department. The Department may approve an anticipated bypass, after considering its adverse effects, if it will meet the three (3) conditions listed in 9.a. above.

c. Notice of Unanticipated Bypass
The permittee shall submit notice to the Department of an unanticipated bypass by calling the Department at the number indicated on the second page of this permit (if the notice is provided after regular working hours, use the following number: 1-800-292-4706) as soon as possible, but no later than 24 hours from the time the permittee becomes aware of the circumstances.

PART II

Section C. Reporting Requirements

d. Written Report of Bypass
A written submission shall be provided within five (5) working days of commencing any bypass to the Department, and at additional times as directed by the Department. The written submission shall contain a description of the bypass and its cause; the period of bypass, including exact dates and times, and if the bypass has not been corrected, the anticipated time it is expected to continue; steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass; and other information as required by the Department.

e. Bypass Not Exceeding Limitations
The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to ensure efficient operation. These bypasses are not subject to the provisions of 9.a., 9.b., 9.c., and 9.d., above. This provision does not relieve the permittee of any notification responsibilities under Part II.C.11. of this permit.

f. Definitions

1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

10. Bioaccumulative Chemicals of Concern (BCC)

Consistent with the requirements of R 323.1098 and R 323.1215 of the Michigan Administrative Code, the permittee is prohibited from undertaking any action that would result in a lowering of water quality from an increased loading of a BCC unless an increased use request and antidegradation demonstration have been submitted and approved by the Department.

11. Notification of Changes in Discharge

The permittee shall notify the Department, in writing, as soon as possible but no later than 10 days of knowing, or having reason to believe, that any activity or change has occurred or will occur which would result in the discharge of: 1) detectable levels of chemicals on the current Michigan Critical Materials Register, priority pollutants or hazardous substances set forth in 40 CFR 122.21, Appendix D, or the Pollutants of Initial Focus in the Great Lakes Water Quality Initiative specified in 40 CFR 132.6, Table 6, which were not acknowledged in the application or listed in the application at less than detectable levels; 2) detectable levels of any other chemical not listed in the application or listed at less than detection, for which the application specifically requested information; or 3) any chemical at levels greater than five times the average level reported in the complete application (see the first page of this permit, for the date(s) the complete application was submitted). Any other monitoring results obtained as a requirement of this permit shall be reported in accordance with the compliance schedules.

PART II

Section C. Reporting Requirements

12. Changes in Facility Operations

Any anticipated action or activity, including but not limited to facility expansion, production increases, or process modification, which will result in new or increased loadings of pollutants to the receiving waters must be reported to the Department by a) submission of an increased use request (application) and all information required under R 323.1098 (Antidegradation) of the Water Quality Standards or b) by notice if the following conditions are met: 1) the action or activity will not result in a change in the types of wastewater discharged or result in a greater quantity of wastewater than currently authorized by this permit; 2) the action or activity will not result in violations of the effluent limitations specified in this permit; 3) the action or activity is not prohibited by the requirements of Part II.C.10.; and 4) the action or activity will not require notification pursuant to Part II.C.11. Following such notice, the permit or, if applicable, the facility's COC may be modified according to applicable laws and rules to specify and limit any pollutant not previously limited.

13. Transfer of Ownership or Control

In the event of any change in control or ownership of facilities from which the authorized discharge emanates, the permittee shall submit to the Department 30 days prior to the actual transfer of ownership or control a written agreement between the current permittee and the new permittee containing: 1) the legal name and address of the new owner; 2) a specific date for the effective transfer of permit responsibility, coverage and liability; and 3) a certification of the continuity of or any changes in operations, wastewater discharge, or wastewater treatment.

If the new permittee is proposing changes in operations, wastewater discharge, or wastewater treatment, the Department may propose modification of this permit in accordance with applicable laws and rules.

14. Operations and Maintenance Manual

For wastewater treatment facilities that serve the public (and are thus subject to Part 41 of the NREPA), Section 4104 of Part 41 and associated Rule 2957 of the Michigan Administrative Code allow the Department to require an Operations and Maintenance (O&M) Manual from the facility. An up-to-date copy of the O&M Manual shall be kept at the facility and shall be provided to the Department upon request. The Department may review the O&M Manual in whole or in part at its discretion and require modifications to it if portions are determined to be inadequate.

At a minimum, the O&M Manual shall include the following information: permit standards; descriptions and operation information for all equipment; staffing information; laboratory requirements; record keeping requirements; a maintenance plan for equipment; an emergency operating plan; safety program information; and copies of all pertinent forms, as-built plans, and manufacturer's manuals.

Certification of the existence and accuracy of the O&M Manual shall be submitted to the Department at least sixty days prior to start-up of a new wastewater treatment facility. Recertification shall be submitted sixty days prior to start-up of any substantial improvements or modifications made to an existing wastewater treatment facility.

PART II

Section C. Reporting Requirements

15. Signatory Requirements

All applications, reports, or information submitted to the Department in accordance with the conditions of this permit and that require a signature shall be signed and certified as described in the Federal Act and the NREPA.

The Federal Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

The NREPA (Section 3115(2)) provides that a person who at the time of the violation knew or should have known that he or she discharged a substance contrary to this part, or contrary to a permit, COC, or order issued or rule promulgated under this part, or who intentionally makes a false statement, representation, or certification in an application for or form pertaining to a permit or COC or in a notice or report required by the terms and conditions of an issued permit or COC, or who intentionally renders inaccurate a monitoring device or record required to be maintained by the Department, is guilty of a felony and shall be fined not less than $2,500.00 or more than $25,000.00 for each violation. The court may impose an additional fine of not more than $25,000.00 for each day during which the unlawful discharge occurred. If the conviction is for a violation committed after a first conviction of the person under this subsection, the court shall impose a fine of not less than $25,000.00 per day and not more than $50,000.00 per day of violation. Upon conviction, in addition to a fine, the court in its discretion may sentence the defendant to imprisonment for not more than 2 years or impose probation upon a person for a violation of this part. With the exception of the issuance of criminal complaints, issuance of warrants, and the holding of an arraignment, the circuit court for the county in which the violation occurred has exclusive jurisdiction. However, the person shall not be subject to the penalties of this subsection if the discharge of the effluent is in conformance with and obedient to a rule, order, permit, or COC of the Department. In addition to a fine, the attorney general may file a civil suit in a court of competent jurisdiction to recover the full value of the injuries done to the natural resources of the state and the costs of surveillance and enforcement by the state resulting from the violation.

16. Electronic Reporting

Upon notice by the Department that electronic reporting tools are available for specific reports or notifications, the permittee shall submit electronically all such reports or notifications as required by this permit.

PART II

Section D. Management Responsibilities

1. Duty to Comply

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit, more frequently than, or at a level in excess of, that authorized, shall constitute a violation of the permit.

It is the duty of the permittee to comply with all the terms and conditions of this permit. Any noncompliance with the Effluent Limitations, Special Conditions, or terms of this permit constitutes a violation of the NREPA and/or the Federal Act and constitutes grounds for enforcement action; for permit or Certificate of Coverage (COC) termination, revocation and reissuance, or modification; or denial of an application for permit or COC renewal.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

2. Operator Certification

The permittee shall have the waste treatment facilities under direct supervision of an operator certified at the appropriate level for the facility certification by the Department, as required by Sections 3110 and 4104 of the NREPA. Permittees authorized to discharge storm water shall have the storm water treatment and/or control measures under direct supervision of a storm water operator certified by the Department, as required by Section 3110 of the NREPA.

3. Facilities Operation

The permittee shall, at all times, properly operate and maintain all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes adequate laboratory controls and appropriate quality assurance procedures.

4. Power Failures

In order to maintain compliance with the effluent limitations of this permit and prevent unauthorized discharges, the permittee shall either:

a. provide an alternative power source sufficient to operate facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit; or

b. upon the reduction, loss, or failure of one or more of the primary sources of power to facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit, the permittee shall halt, reduce or otherwise control production and/or all discharge in order to maintain compliance with the effluent limitations and conditions of this permit.

5. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to the surface waters or groundwaters of the state resulting from noncompliance with any effluent limitation specified in this permit including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the discharge in noncompliance.

PART II

Section D. Management Responsibilities

6. Containment Facilities

The permittee shall provide facilities for containment of any accidental losses of polluting materials in accordance with the requirements of the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code). For a Publicly Owned Treatment Work (POTW), these facilities shall be approved under Part 41 of the NREPA.

7. Waste Treatment Residues

Residuals (i.e. solids, sludges, biosolids, filter backwash, scrubber water, ash, grit, or other pollutants or wastes) removed from or resulting from treatment or control of wastewaters, including those that are generated during treatment or left over after treatment or control has ceased, shall be disposed of in an environmentally compatible manner and according to applicable laws and rules. These laws may include, but are not limited to, the NREPA, Part 31 for protection of water resources, Part 55 for air pollution control, Part 111 for hazardous waste management, Part 115 for solid waste management, Part 121 for liquid industrial wastes, Part 301 for protection of inland lakes and streams, and Part 303 for wetlands protection. Such disposal shall not result in any unlawful pollution of the air, surface waters or groundwaters of the state.

8. Right of Entry

The permittee shall allow the Department, any agent appointed by the Department, or the Regional Administrator, upon the presentation of credentials and, for animal feeding operation facilities, following appropriate biosecurity protocols:

a. to enter upon the permittee's premises where an effluent source is located or any place in which records are required to be kept under the terms and conditions of this permit; and

b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect process facilities, treatment works, monitoring methods and equipment regulated or required under this permit; and to sample any discharge of pollutants.

9. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Act and Rule 2128 (R 323.2128 of the Michigan Administrative Code), all reports prepared in accordance with the terms of this permit, shall be available for public inspection at the offices of the Department and the Regional Administrator. As required by the Federal Act, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Act and Sections 3112, 3115, 4106 and 4110 of the NREPA.

10. Duty to Provide Information

The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or the facility's COC, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit such facts or information.

PART II

Section E. Activities Not Authorized by This Permit

1. Discharge to the Groundwaters

This permit does not authorize any discharge to the groundwaters. Such discharge may be authorized by a groundwater discharge permit issued pursuant to the NREPA.

2. POTW Construction

This permit does not authorize or approve the construction or modification of any physical structures or facilities at a POTW. Approval for the construction or modification of any physical structures or facilities at a POTW shall be by permit issued under Part 41 of the NREPA.

3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypass" (Part II.C.9. pursuant to 40 CFR 122.41(m)), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance, whether or not such noncompliance is due to factors beyond the permittee's control, such as accidents, equipment breakdowns, or labor disputes.

4. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee may be subject under Section 311 of the Federal Act except as are exempted by federal regulations.

5. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Federal Act.

6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize violation of any federal, state or local laws or regulations, nor does it obviate the necessity of obtaining such permits, including any other Department of Environmental Quality permits, or approvals from other units of government as may be required by law.

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

APPALACHIAN VOICES, et al.,	)	
Petitioners,	)	
v.	)	No. 20-2187 (L)
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,	)	
Respondents.	)	

UNOPPOSED MOTION TO HOLD MERITS BRIEFING SCHEDULE IN ABEYANCE

Respondents move for an order extending the abeyance of merits briefing in this case until July 24, 2021. In support of this motion, Respondents state as follows:

1. This action involves two consolidated petitions for review challenging EPA's final rule entitled "Steam Electric Reconsideration Rule," 85 Fed. Reg. 64,650 (Oct. 13, 2020).

2. Intervenor Utility Water Act Group filed a motion to transfer the consolidated petitions to the Fifth Circuit. Mot. to Transfer (Dec. 2,

2020), Doc. No. 17. That motion is fully briefed, and it remains pending. Doc. Nos. 37, 38, 39, 47, 48, 49.

3. On January 20, 2021, the Court granted the parties' joint motion to hold the merits briefing schedule in abeyance until February 24, 2021, which was the deadline for interested persons to petition for review of the Steam Electric Reconsideration Rule. Order (Jan. 20, 2021), Doc. No. 51; *see also* 33 U.S.C. § 1369(b)(1).

4. Also on January 20, 2021, the incoming presidential administration issued Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis," 86 Fed. Reg. 7037 (Jan. 20, 2021). The executive order directed agencies to review agency actions taken between January 20, 2017 and January 20, 2021 to ensure their consistency with certain policies stated in the executive order. *Id.* at 7037.

5. The Steam Electric Reconsideration Rule was part of the non-exclusive list of actions identified for EPA's review pursuant to the executive order. Doc. No. 52-2.

6. On March 1, 2021, the Court granted Respondents' unopposed motion to extend the abeyance of the merits briefing

schedule until May 25, 2021 to allow EPA to conduct its review of the Steam Electric Reconsideration Rule. Order (Mar. 1, 2021), Doc. No. 53.

7. Since then, EPA has been working diligently to review the Steam Electric Reconsideration Rule, including by gathering additional information and holding several substantive internal briefings for new agency leadership. Additional briefings for agency leadership on the technical, legal, and policy issues regarding the steam electric guidelines are planned for the near future. Due to the significance and complexity of this review, an additional 60 days is necessary to give senior EPA leadership sufficient time to complete their review.

8. Respondents request that merits briefing in this case continue to be held in abeyance for an additional 60 days beyond May 25, 2021 — i.e., until July 24, 2021 — to allow EPA the necessary additional time to review the Steam Electric Reconsideration Rule.

9. EPA intends to and expects to reach a decision on whether to initiate a new rulemaking to revise the Steam Electric Reconsideration Rule by no later than the end of that additional 60-day period.

10. Deferring merits briefing to allow EPA to continue to review the Steam Electric Reconsideration Rule would be most efficient for

both the Court and the parties. If EPA decides to initiate a rulemaking to revise any aspect of the Rule, then that rulemaking could obviate the need for the Court to decide certain issues in this case.

11. All other parties to this consolidated litigation have stated that they do not oppose this motion.

Respectfully submitted,

JEAN E. WILLIAMS
Acting Assistant Attorney General

<u>/s/ Tsuki Hoshijima</u>
TSUKI HOSHIJIMA
U.S. Department of Justice
Environment and Natural Resources Division
Environmental Defense Section
P.O. Box 7611
Washington, D.C. 20044
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Counsel for Respondents

CERTIFICATE OF COMPLIANCE

I certify that the foregoing filing complies with the word limit of Fed. R. App. P. 27(d)(2)(A) because it contains 529 words, excluding the parts of the filing exempted by Fed. R. App. P. 32(f). The filing complies with the typeface and type style requirements of Fed. R. App. P.

32(a)(5) and (a)(6) because it was prepared in a proportionately spaced typeface using Microsoft Word 2016 in Century Schoolbook fourteen-point font.

/s/ Tsuki Hoshijima

CERTIFICATE OF SERVICE

I hereby certify that on May 25, 2021, I filed the foregoing using the Court's CM/ECF system, which will electronically serve all counsel of record registered to use the CM/ECF system.

/s/ Tsuki Hoshijima

FILED: June 1, 2021

UNITED STATES COURT OF APPEALS
FOR THE FOURTH CIRCUIT

No. 20-2187 (L)
(EPA-HQ-OW-2009-0819; EPA-85FR64650)

APPALACHIAN VOICES; GOOD STEWARDS OF ROCKINGHAM; STOKES COUNTY BRANCH OF THE NAACP; WINYAH RIVERS ALLIANCE

Petitioners

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY; MICHAEL S. REGAN, in his official capacity as Administrator of the United States Environmental Protection Agency

Respondents

UTILITY WATER ACT GROUP; ELECTRIC ENERGY, INC.; COLETO CREEK POWER, LLC; DYNEGY MIAMI FORT, LLC; DYNEGY MIDWEST GENERATION, LLC; DYNEGY ZIMMER, LLC; ILLINOIS POWER GENERATING COMPANY; ILLINOIS POWER RESOURCES GENERATING, LLC; KINCAID GENERATION, L.L.C.

Intervenors

O R D E R

Upon consideration of respondent's unopposed motion to hold the merits briefing schedule in abeyance, the court grants the motion and extends the abeyance until July 24, 2021.

For the Court

/s/ Patricia S. Connor, Clerk

U20963-MEC-CE-027
Page **1** of **2**

Question:

20. Refer to the Direct Testimony of Scott A. Hugo. Is the Company requesting rate recovery of any capital and/or major maintenance expenditures at Campbell or Karn that were disallowed or deferred in Case No. U-20697? If yes, please identify each such expenditure, including the following information:
a. the specific unit or common area where the project was or would be performed;
b. the Work ID and project description (e.g., "5566 - JHC 2 PJFF bag replacement);
c. the actual or projected cost for the project, and the year(s) in which such costs would be incurred;
d. the project's Approval Criteria category (e.g., economic, safety/compliance/regulatory, etc.) at the time of the Company's initial filing in Case U-20697;
i. If the project's Approval Criteria category has changed since February 27, 2020, please identify the current Approval Criteria category and the date when that category changed. Please also produce any documentation and/or analysis supporting the Company's decision to change the Approval Criteria category.
e. Please identify:
i. the month and year in which the project was or will be commenced.
ii. the month and year in which the project was or will be completed.
f. Please identify which, if any, of these capital and major maintenance projects the Company contends would be necessary if Campbell Units 1 and/or 2 retired in 2024 or 2025.
i. For each project identified in your response to subpart (f), please provide any documentation supporting the Company's contention.
Note: this request seeks information regarding all disallowances at Campbell and Karn, regardless of timeframe (including projects before or after the 2022 test year in this case).

Response:

a. Please see Attachment U20963-MEC-CE-027 which contains a list of the Campbell and Karn capital and major maintenance projects which received either a partial or full disallowance in Case U-20697. The attachment includes the data requested in subparts (a) - (d). The approval criteria for these projects has not changed since February 27, 2020.

b. See response to subpart (a).

c. See response to subpart (a).

d. See response to subpart (a).

e.

i. See response to subpart (a).
ii. See response to subpart (a).

f.

i. All projects listed in U20963-MEC-CE-027_ATT_1 will be necessary except for 5589 – JHC1 SH Outlet Pendant Tube Panel Replacements. The approach taken to develop the decision to identify a project as avoidable or unavoidable is based on the philosophy of running the units in a safe, regulatory compliant manner through end of life and allowing for a reasonable decrease in availability and reliability. Ultimately these units need to continue to serve our customers when required. See also the Company's responses in U20963-MEC-CE-023 and U20963-MEC-CE-024.

Scott A. Hugo
April 12, 2021

Director – Generation Asset Strategy

	Coal Generation Capital	2020	2021	2022	Estimated Month/Year Commenced	Estimated Month/Year Completion
	Campbell 1					
Reliability	5543 -JHC1 Mill Overhaul		$ 696,000.00	$ -	5/21	7/21
General Maintenance	5589 -JHC1 SH Outlet Pendant Tube Panel Replacements		$ -	$ 20,000.00	2/22	12/24
General Maintenance	9650 -JHC1 Major Motor and Pump Overhauls		$ 200,000.00	$ 200,000.00	1/21	12/22
General Maintenance	9653 -JHC1 Balance of Plant Equipment		$ 135,000.00	$ 135,000.00	1/21	12/22
Other Environmental	9655 -JHC1 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
	Campbell 1&2 Commons					
316b	5538 -JHC 1&2 - 316B Deep Water Intake		$ 500,000.00	$ 7,600,000.00	12/21	12/23
	Campbell 2					
General Maintenance	3089 -JHC2 Mill Overhauls (grinding section & gearbox)		$ 400,000.00	$ -	10/21	12/21
Other Environmental	5462 -JHC2 SAH Baskets and Seals		$ 2,735,000.00	$ -	2/18	12/21
Reliability	5545 -JHC2 Overhaul Hydraulic Coupling Rotor		$ 459,000.00	$ -	2/20	12/21
Reliability	5573 -JHC 2 Overhaul CCWP & Motors		$ 580,000.00	$ -	1/21	12/21
General Maintenance	5577 -JHC2 - Overhaul JHC2 FD Fan Motors		$ 402,000.00	$ -	10/21	11/21
Reliability	5594 -JHC2 Main BFP overhaul		$ 359,000.00	$ -	10/21	11/21
Reliability	5663 -JHC 2 2A Condensate Pump Overhaul		$ 210,000.00	$ -	10/21	11/21
General Maintenance	9651 -JHC2 Major Motor and Pump Overhauls		$ 200,000.00	$ 200,000.00	1/21	12/22
General Maintenance	9654 -JHC2 Balance of Plant Equipment Replacements		$ 135,000.00	$ 135,000.00	1/21	12/22
Other Environmental	9656 -JHC2 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
	Campbell 3					
General Maintenance	5691 -JHC3 Replace O2 monitors		$ 944,600.00	$ 904,600.00	2/21	12/22
Reliability	5693 -JHC3 Mill Complete Overhauls		$ 1,335,000.00	$ 1,264,800.00	1/21	12/22
General Maintenance	5707 -JHC3 Reheater Sootblower		$ 1,350,000.00	$ -	9/20	12/21
General Maintenance	5708 -JHC3 Sootblowing Air Compressor Controls		$ -	$ 250,000.00	1/22	12/22
Reliability	9671 -JHC Fuel Handling/Infrastructure Replacements		$ 500,000.00	$ 750,000.00	1/21	12/22
Reliability	9690 -JHC3 Balance of Plant Equipment Replacements		$ 180,000.00	$ 180,000.00	1/21	12/22
Other Environmental	9692 -JHC3 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
	Campbell Site Commons					
Regulatory	9528 Bottom Ash Tanks Chemical Treatment System	$ 1,619,212.61	$ 100,000.00		7/19	4/22
Reliability	5480 -JHC FH Replace Fuel Handling Conveyor Belts		$ 427,000.00	$ -	4/21	12/21
Regulatory	9395 -JHC Dry Ash Landfill Cell Construction & Permitting		$ 5,482,830.00	$ -	1/21	12/21
SEEG	5523 -JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.		$ 1,928,742.00	$ 15,421,498.00	1/21	12/23
	Karn 1&2 Commons		$ 11,796,862.00	$ 15,900,064.00		
Asset Retirement Costs	9929 -Karn 1&2 Decommissioning		$ 11,295,862.00	$ 15,675,064.00	5/19	12/26

	Coal Generation O&M	2020	2021	2022		
	Campbell 1&2 Commons					
General Major Maintenance	5596 -JHC1-2 Breaker Maintenance		$ 100,000.00	$ 100,000.00	1/21	12/22
General Major Maintenance	5597 -JHC1&2 Medium Voltage Breaker Inspection & Cleaning		$ 60,000.00	$ 60,000.00	1/21	12/22

Question:

3. Refer to your response to MEC-CE-27, which states that "[t]he approval criteria for [the previously disallowed Campbell and Karn] projects has not changed since February 27, 2020."
a. Please reconcile this statement with attachment U20963-MEC-CE-027-Hugo_ATT_1, which lists different criteria than the criteria identified in Case No. U-20697. (For example, whereas project no. 5543 was identified as an "equipment condition" in Case U-20697, see U20697-MEC-CE-1014-Hugo_ATT_1, cell J92, this project is now listed as a "reliability" project. See U20963-MEC-CE-027-Hugo_ATT_1.)

Response:

The approval criteria has not changed for these projects. Column A on Attachment U20963-MEC-CE-027-Hugo_ATT_1 reflected the tier 4 portfolio name rather than the approval criteria. Attachment U20963-MEC-CE-638_ATT_1 includes the approval criteria for disallowed projects.

Scott A. Hugo
May 13, 2021

Director – Generation Asset Strategy

		Coal Generation Capital	2020	2021	2022	Estimated Month/Year Commenced	Estimated Month/Year Completion
		Campbell 1					
Reliability	Equipment Condition	5543 -JHC1 Mill Overhaul		$ 696,000.00	$ -	5/21	7/21
General Maintenance	Economic & Equipment Condition	5589 -JHC1 SH Outlet Pendant Tube Panel Replacements		$ -	$ 20,000.00	2/22	12/24
General Maintenance	Equipment Condition	9650 -JHC1 Major Motor and Pump Overhauls		$ 200,000.00	$ 200,000.00	1/21	12/22
General Maintenance	Equipment Condition	9653 -JHC1 Balance of Plant Equipment		$ 135,000.00	$ 135,000.00	1/21	12/22
Other Environmental	Equipment Condition	9655 -JHC1 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
		Campbell 1&2 Commons					
316b	Safety/Compliance/Regulatory	5538 -JHC 1&2 - 316B Deep Water Intake		$ 500,000.00	$ 7,600,000.00	12/21	12/23
		Campbell 2					
General Maintenance	Equipment Condition	3089 -JHC2 Mill Overhauls (grinding section & gearbox)		$ 400,000.00	$ -	10/21	12/21
Other Environmental	Economic & Equipment Condition	5462 -JHC2 SAH Baskets and Seals		$ 2,735,000.00	$ -	2/18	12/21
Reliability	Equipment Condition	5545 -JHC2 Overhaul Hydraulic Coupling Rotor		$ 459,000.00	$ -	2/20	12/21
Reliability	Equipment Condition	5573 -JHC 2 Overhaul CCWP & Motors		$ 580,000.00	$ -	1/21	12/21
General Maintenance	Equipment Condition	5577 -JHC2 - Overhaul JHC2 FD Fan Motors		$ 402,000.00	$ -	10/21	11/21
Reliability	Equipment Condition	5594 -JHC2 Main BFP overhaul		$ 359,000.00	$ -	10/21	11/21
Reliability	Equipment Condition	5663 -JHC 2 2A Condensate Pump Overhaul		$ 210,000.00	$ -	10/21	11/21
General Maintenance	Equipment Condition	9651 -JHC2 Major Motor and Pump Overhauls		$ 200,000.00	$ 200,000.00	1/21	12/22
General Maintenance	Equipment Condition	9654 -JHC2 Balance of Plant Equipment Replacements		$ 135,000.00	$ 135,000.00	1/21	12/22
Other Environmental	Equipment Condition	9656 -JHC2 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
		Campbell 3					
General Maintenance	Safety/Compliance/Regulatory	5691 -JHC3 Replace O2 monitors		$ 944,600.00	$ 904,600.00	2/21	12/22
Reliability	Equipment Condition	5693 -JHC3 Mill Complete Overhauls		$ 1,335,000.00	$ 1,264,800.00	1/21	12/22
General Maintenance	Economic	5707 -JHC3 Reheater Sootblower		$ 1,350,000.00	$ -	9/20	12/21
General Maintenance	Equipment Condition	5708 -JHC3 Sootblowing Air Compressor Controls		$ -	$ 250,000.00	1/22	12/22
Reliability	Equipment Condition	9671 -JHC Fuel Handling/Infrastructure Replacements		$ 500,000.00	$ 750,000.00	1/21	12/22
Reliability	Equipment Condition	9690 -JHC3 Balance of Plant Equipment Replacements		$ 180,000.00	$ 180,000.00	1/21	12/22
Other Environmental	Equipment Condition	9692 -JHC3 AQCS Projects		$ 250,000.00	$ 250,000.00	1/21	12/22
		Campbell Site Commons					
Regulatory	Safety/Compliance/Regulatory	9528 Bottom Ash Tanks Chemical Treatment System	$ 1,619,212.61	$ 100,000.00		7/19	4/22
Reliability	Equipment Condition	5480 -JHC FH Replace Fuel Handling Conveyor Belts		$ 427,000.00	$ -	4/21	12/21
Regulatory	Safety/Compliance/Regulatory	9395 -JHC Dry Ash Landfill Cell Construction & Permitting		$ 5,482,830.00	$ -	1/21	12/21
SEEG	Safety/Compliance/Regulatory	5523 -JH Campbell Site SEEG - Compliance - Closed Loop W/ Recirc.		$ 1,928,742.00	$ 15,421,498.00	1/21	12/23
		Karn 1&2 Commons		$ 11,796,862.00	$ 15,900,064.00		
Asset Retirement Costs	Unit Separation	9929 -Karn 1&2 Decommissioning		$ 11,295,862.00	$ 15,675,064.00	5/19	12/26

		Coal Generation O&M	2020	2021	2022		
		Campbell 1&2 Commons					
General Major Maintenance	Equipment Condition	5596 -JHC1-2 Breaker Maintenance		$ 100,000.00	$ 100,000.00	1/21	12/22
General Major Maintenance	Equipment Condition	5597 -JHC1&2 Medium Voltage Breaker Inspection & Cleaning		$ 60,000.00	$ 60,000.00	1/21	12/22

MEC-66C

CONFIDENTIAL EXHIBIT

Question:

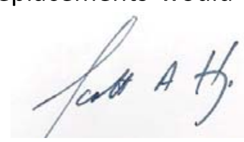
7. Refer to the "MEC-CE-044_ATT_1" and "MEC-CE-035_ATT_12 Revised" spreadsheets.
a. MEC-CE-035_ATT_12 Revised identifies IRRs for five capital projects at Campbell planned for 2021 (project nos. 5586, 5462, 9950, 5747, and 8639). Has the Company performed an IRR or PVR for any other capital project (regardless 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 controls 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

<u>Question:</u>

21. Refer to pages 49-57 of the Direct Testimony of Norman J. Kapala in Case No. U-20165, and to discovery response U20697-MEC-CE-53 from Case No. U-20697.

    a. Please produce in discovery in this case (or, alternatively, indicate permission to use in this case) the Karn community transition plan, which was provided in Case U-20796 as confidential discovery attachment "U20697-MEC-CE-053- Hugo_CONF_ATT_1."

    b. Further refer to U20697-MEC-CE-053(a)(i), which notes that the Karn community transition plan has not "been updates since [it was] provided in Case No. U-20165."

       At present – i.e., as of April 5, 2021 – has the community transition plan been updated since Case No. U-20165?

       i. If so, please provide a copy of the current version of the community transition plan.

       ii. If not, please explain why not.

    c. Please identify actual or projected expenditures for each of the years 2020-2024 associated with implementing (i) the community transition plan, and (ii) the future use study.

    d. Please describe in detail any plans by the Company to assist in the economic redevelopment of areas that will likely be affected by the retirement of Karn 1 and 2.

    e. Please describe any workforce retraining opportunities Consumers has made or is planning to make available for Karn employees.

    f. Please identify and describe any attempt Consumers has made since April 2020 to get community input or engage in public participation planning related to the Karn retirements. (Such attempts include, but are not limited to, holding formal or informal public meetings, meeting with local officials, and meeting with community stakeholders.)

    g. Has Consumers entered into any community benefit agreement related to the planned retirement of Karn 1 and 2? If so, please identify and provide a copy of such agreement.

    h. Further refer to discovery response U20697-MEC-CE-059(c) from Case No. U-20697, which notes the Company's intention to complete a future use study for the Karn site "between the 3rd quarter of 2020 and 2nd quarter of 2021." Please provide an update on the status of these efforts, and produce the current version of any future use study related to Karn.

<u>Response:</u>

<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request to the extent that it is irrelevant and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:

a. The Company grants the permission for use in this case the Karn community transition plan which was provided as confidential discovery attachment U20697-MEC-CE-053-Hugo_CONF_ATT_1.

b. No changes have been made to this document since it was provided in U-20165.
   i. Not applicable.
   ii. The community transition plan is based on the planned retirement of Karn Units 1 and 2. In Case No. U-20165, the parties to the approved IRP Settlement Agreement agreed that Karn Units 1 and 2 will retire in 2023. There have been no changes to the agreed upon retirement date of Karn Units 1 and 2.

c. Please see attachment U20963-MEC-CE_028_ATT_1 for a preliminary estimate of costs for 2020-2024. The Company is currently in the process of developing an updated IRP to be filed in June 2021, which may influence any updates/revisions to the document. Additional questions regarding this document would be more appropriate for that proceeding.

d. An alternatives analysis will be completed during the upcoming Karn Unit 1 and 2 retirement process identifying which redevelopment scenarios may best fit the relevant available properties. This will occur during the course of 2021.

e. The Company is currently assembling a workforce planning team to identify, review and implement actionable retraining opportunities. However, the Company is not yet at a point of detail where individual areas of identification have occurred. This is expected to be accomplished in a late 2021-2022 timeframe.

f. Due to COVID19 restrictions, update and alignment opportunities with local Stakeholders have been restrained. The Company plans to begin virtual quarterly updates again in 2021 starting 1st to 2nd quarter. An organic meeting with Hampton Township Supervisor was held on Monday, April 5th 2021 to provide an opportunity for any questions or relevant updates in Karn Site activity related to ongoing decommissioning efforts. Similarly, a meeting with Bay Future is taking place on April 7th 2021.

g. No. Consumers Energy has not entered into any such agreement.

h. The future use/alternatives analysis study process is in progress and as mentioned in the referenced statement, "between the 3rd quarter of 2020 and 2nd quarter of 2021". Solicitation and award has been completed and the awarded Contractor will provide a draft according to the communicated schedule.

Scott A. Hugo
April 13, 2021

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

<u>Question:</u>

24. Refer to your response to MEC-CE-28.
a. Further refer to your response to MEC-CE-28(b)(ii). Please confirm that the Company does not intend to update or supplement the community transition plan
for Karn 1 and 2.
i. If not confirmed, please describe any plans to update/supplement the plan, including the timeline for such supplementation.
ii. Will the Company submit an updated community transition plan with its June 2021 IRP filing?
b. Refer to your response to MEC-CE-28(d) which discusses the development of an alternatives analysis.
i. Please identify the person(s) or entity(ies) that will be performing this analysis.
ii. When will this analysis will be completed?
iii. Will the results of this analysis be presented in the Company's IRP filing?
If not, please describe any plans to share the results of this analysis publicly.
c. Refer to your response to MEC-CE-28(e). Please describe the composition of the workforce planning team. Will this team be led by the Company, or an outside contractor?
d. Refer to your response MEC-CE-28(f)
i. Please share any written materials that the Company presented at the meetings with the Hampton Township Supervisor and Bay Future.
ii. Does the Company plan to take any follow-up actions as a result of these meetings?
iii. Who will be invited to the virtual quarterly update meetings? Are those meetings open to the interested public?
iv. Please state whether the first quarterly update has been scheduled, and if so, when such meeting has or will be held.
e. Refer to your response to MEC-CE-28(h). When is the contractor scheduled to provide a draft of the future use study?

<u>Response:</u>

a. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is irrelevant and not proportional to the needs of this case. Subject to that objection, and without waiving it, the Company provides the following response:**

   i. The plan presented in the 2018 IRP is the current plan.

   ii. See subpart (i).

b. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

c. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

d. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

e. **<u>Objection of Counsel:</u> Consumers Energy Company objects to this discovery request because it is unclear, irrelevant, overly broad, and not proportional to the needs of this case.**

Scott A. Hugo
May 14, 2021

Director – Generation Asset Strategy

<u>Question:</u>

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?

<u>Response:</u>

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 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

MEC-69C

CONFIDENTIAL EXHIBIT

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-20963 ALJ Sharon Feldman

PROOF OF SERVICE

On the date below, an electronic copy of **PUBLIC VERSION of the Direct Testimony 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, and CUB

Date: June 22, 2021

By: Karla L Gerds
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Date: 2021.06.22 16:52:39 -04'00'

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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-20963 ALJ Sharon Feldman

CONFIDENTIAL
PROOF OF SERVICE

On the date below, an electronic copy of **CONFIDENTIAL VERSION of the Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

Name/Party	E-mail Address
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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, and CUB

Date: June 22, 2021

Karla L Gerds

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