BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-7
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 1

May Order

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

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[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id*.
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

<u>Michigan Public Service Commissioners</u>
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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Exhibit 2

Grid Strategies June Report

A Review of DOE's 202(c) Order for the Campbell Coal Plant

Michael Goggin

June 18, 2025

I. Executive Summary

On May 23, 2025, the U.S. Department of Energy ("DOE") issued an order under Section 202(c) of the Federal Power Act directing the Midcontinent Independent System Operator ("MISO") and utility Consumers Energy to take "all measures necessary" to ensure the continued availability of the J.H. Campbell coal power plant in Michigan for three months, past its scheduled retirement date on May 31, 2025.[1] The DOE order claims there is an emergency due to insufficient "dispatchable capacity" in MISO. The order does not define dispatchable capacity and does not clearly indicate the basis on which the Energy Secretary believes there is a shortfall of dispatchable resources. In my experience, "dispatchable" generally refers to generating resources that can change their level of output on command, and a stated lack of "capacity" is a claim that there will be insufficient electricity supply during periods of peak demand, a need often referred to as "resource adequacy."

This report is organized into four sections. First, it provides brief background on the methods grid planners use to ensure electricity supply is adequate to meet demand. Next, it reviews how utilities, state regulators, regional grid operators, and reliability regulators use planning, regulatory, and market mechanisms to ensure electricity generating supply is adequate to meet demand. Third, it reviews the determinations Consumers Energy, Michigan, and MISO have already made that the Campbell plant is not necessary for meeting anticipated electricity demand this summer, in large part because MISO has a summer capacity surplus of more than 2,600 MW. That section also documents why the North American Electric Reliability Corporation ("NERC") Summer Reliability Assessment that DOE cites to justify its order does not indicate that an emergency exists in the MISO region. Finally, the report explains why the aging Campbell plant is a poor choice for meeting electricity demand this summer, as evidenced by its low availability rates during recent summer peak demand periods.

II. Background on Resource Adequacy Methods

At the outset, it is helpful to explain some relevant terms. "Resource adequacy" generally means having enough supply during periods of peak net system need from generators and from other resources like demand response (programs by which electricity users are compensated for reducing consumption) and energy storage.

There is no one correct amount of resource adequacy: what level is appropriate depends in part on what system planners, regulators, industry, utilities, customers, government, and other stakeholders want to pay for. This question is one of risk versus reward. More resources can always be added to achieve more resource adequacy, but there are diminishing returns if more is invested. As a result, the usual benchmark for acceptable risk of such events occurring is one day of lost load in ten years. In other words, system planners typically seek to have a set of

[1] U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) available at https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

resources such that the system can expect to experience no more than one day containing an outage in ten years. Utilities, state regulators, and regional grid operators have coalesced around this benchmark, and have generally concluded that it appropriately balances the cost of building and maintaining generating capacity versus the cost of potential generation shortfalls. Many state regulators use the one day in ten years criterion to ensure profit-maximizing utilities do not burden ratepayers with the cost of excessive generating capacity. This is largely due to the diminishing marginal returns from a higher planning reserve margin,[2] which is the amount of extra generating capacity that exists in a system above peak load projections, expressed as a percentage of peak load.

To calculate the target reserve margin that achieves a specific risk threshold, planners use sophisticated statistical analyses to simulate electricity demand and supply availability scenarios based on decades of historical weather patterns. The reserve margin thus accounts for interannual variability in peak electricity demand due to extreme weather events and other factors. Planners also use these sophisticated methods to determine the expected contribution of each resource towards meeting peak needs, often called a resource's "capacity value" or "accredited capacity." These methods account for how weather patterns affect the timing of wind and solar output, and how unplanned outages and other factors can cause any resource to have reduced availability during periods of need.[3] Thus, planners account for all of these risks in setting the target reserve margin.

II. Existing State and Regional Measures Already Ensure Reliability and Resource Adequacy.

The regulation and oversight of power grid reliability and resource adequacy have become far more sophisticated and robust since Section 202(c) of the FPA was enacted in 1935. For most of the past century, states and the electric utilities they regulate have had front-line responsibility for ensuring that adequate resources are available to serve the electric power needs of customers in their jurisdictions. In recent decades, two key developments have layered regional and national assurance mechanisms onto the existing state resource adequacy regulations.

First, the Federal Energy Regulatory Commission ("FERC") approved the formation of Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"),

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[2] For example, see K. Carden and A. Dombrowsky, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (Final),* (January 2021) available at https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf, at 34-40; and PJM, *2023 PJM Reserve Requirement Study,* (October 2023) available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx, at 27.

[3] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report,* available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 20-23.

such as MISO. The RTOs and ISOs operate the bulk power transmission system within their service areas – which in several cases (including MISO) cover multiple states – and manage wholesale electricity markets that help ensure resource adequacy.

Second, Congress enacted Section 215 of the FPA in 2005, creating a new reliability regulatory regime overseen by FERC. Pursuant to Section 215, FERC designated NERC as the national Electric Reliability Organization, with responsibility for setting and enforcing national reliability standards, subject to FERC approval. NERC also designates "Regional Entities" that help implement the national standards in their regions and develop region-specific standards, subject to FERC and NERC approval. ReliabilityFirst Corporation ("RFC") is the Regional Entity for Michigan and most of eastern MISO. Together, state utility regulators, ISOs and RTOs, NERC and its subsidiary regional reliability organizations, and FERC share responsibility for assuring the electric grid operates reliably.

A. States and Utilities

The states are responsible for ensuring that the utilities they regulate have adequate resources to meet demand for electric power. In most states, including Michigan, utility regulators have processes through which they evaluate utilities' plans to add new generators, retire old generators, and undertake a host of other activities, with the goal being to identify a prudent resource plan that minimizes costs and risks for ratepayers. I have participated in many of these "integrated resource plan" or "IRP" proceedings, which are detailed, fact-intensive processes in which the regulator and other stakeholders closely review a utility's proposed assumptions and methods. A primary focus of IRP proceedings is ensuring resource adequacy. State regulators have strong incentives to ensure resource adequacy, as a generation shortfall in a state can result in localized blackouts or increased costs for ratepayers.

B. MISO

MISO plays two important roles in ensuring resource adequacy. First, as discussed further below, MISO is a designated Planning Coordinator responsible for implementing the resource adequacy planning standard adopted by RFC. Pursuant to that standard, MISO performs and documents an annual resource adequacy analysis, which is based on the "one day in ten years" loss of load standard. MISO uses that analysis to determine a planning reserve margin for the region, for each season of the upcoming year. MISO then applies that margin to each zone's load projections to determine the planning reserve margin requirement for each zone and season.

Second, MISO runs a residual capacity market that allows utilities and generators to buy and sell capacity to meet each of their four seasonal planning reserve margin requirements. MISO and other grid operators also use energy markets and other tools to ensure that electricity supply meets demand at all times. Each of these markets is discussed in more detail below.

1. Capacity Market

First, MISO sets the planning reserve margin that it determines is required to meet the "one day in ten years" benchmark, and determines resources' capacity accreditation, as discussed above. MISO then applies the planning reserve margin to each zone of MISO. As part of this, MISO uses power flow models to assess how transmission constraints affect the need for generation in each zone in the MISO region.[4] This ensures that there are sufficient resources to meet demand in each zone, after accounting for the transmission capacity available to import power from other zones.

Based on these inputs and zonal requirements, MISO then conducts an annual capacity market auction, and this price signal provides an additional mechanism to incentivize the development and construction of new generation to help meet future resource adequacy needs. The core elements of MISO's capacity market processes have been approved by FERC under its authority to ensure that rates are just, reasonable, and not unduly discriminatory under Section 205 of the Federal Power Act.[5]

If a utility falls short of its resource adequacy obligation to meet its needs plus MISO's reserve margin, it must make up for that shortfall through purchases in the capacity market. If supply is short or import purchases begin to approach the import limit MISO has calculated for a given zone, the price of capacity in that zone will increase. State regulators are cognizant of that risk, and thus have a strong incentive to ensure their utilities have adequate supplies in advance.

2. Real-Time and Near-Term Operations

Each day MISO runs a day-ahead energy market in which generators offer to produce electricity each hour of the next day at a certain price. MISO then compares this supply curve of offers to its demand forecast for the next day, and then "commits" the generators that can meet this demand forecast at lowest cost subject to reliability and transmission constraints. Generators that are committed but were offline start and take other steps required to be online by the next day. The vast majority of electricity is procured in the day-ahead market, but MISO also runs a real-time energy market to fine-tune deviations in supply and demand that occur after the day-ahead market has concluded. The energy markets play an important role in ensuring supply is adequate to meet demand by sending a powerful price signal for generators to maximize their output and for utilities to import power from neighboring regions during periods of need.

MISO also operates "ancillary services" markets, which procure other services like operating reserves from flexible resources that help balance fast variability in supply and demand. Prices in these markets are typically very low as MISO has a large supply of flexible

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[4] *Id.* at 36-55.
[5] FERC Docket Nos. 11-4081; EL15-70 *et al*.; ER22-495; ER23-2977; ER24-1638.

resources,[6] and that supply is increasing as batteries and other flexible resources replace inflexible coal and nuclear generators.

As a result, there is no indication of a need for "dispatchable" resources, as claimed by DOE's Order, to provide additional flexibility in MISO. If a need for more flexibility arose at any point in time, prices for ancillary services would simply increase, spurring flexible generators that were offline to start up and provide flexibility until the need has passed. Regardless, coal plants like Campbell are not very dispatchable compared to other generating resources, with long startup times, slow output ramp rates, and high minimum output levels. This can also reduce their capacity contribution to meeting peak demand needs, particularly those that arise on short notice.

If MISO encounters a risk of a generation shortage in real-time operations, it has numerous additional tools that it can deploy in a stepwise fashion to help ensure supply is adequate to meet demand.[7] The impact of many of these steps is not fully accounted for in MISO's loss of load analysis, making that planning conservative.

Days in advance of expected extreme heat, cold, or other severe weather, MISO can issue an alert or declare Conservative System Operations, directing transmission and generating resources on planned outages to return to service and make other preparations.[8] NERC notes this step helped ensure resource adequacy in MISO last summer.[9] As noted below, NERC's "elevated risk" designation for MISO is based on the assumption that many generators are on outage, so by taking steps to reduce generator outages MISO can reduce that risk.

Next, MISO can progress to issuing a capacity warning, which activates numerous additional steps to increase supply, including activating emergency pricing, and curtailing non-firm exports.[10] If the event then progresses to step 1a, MISO activates demand response resources, which are customers that are compensated for reducing their demand during periods of need. If an event progresses to step 1b, generating units are directed to operate at their

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[6] Potomac Economics, 2023 State of the Market Report for the MISO Electricity Markets, (June 2024) available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 8-9.
[7] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 37-39.
[8] MISO, *Conservative System Operations*, available at https://cdn.misoenergy.org/SO-P-NOP-00-449%20Rev%2010%20Conservative%20System%20Operations688847.pdf
[9] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 51, referring to summer 2024: "MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages."
[10] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 10-12.

emergency maximum limits. If the event escalates further, MISO can then progress through additional steps including activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed.[11]

C. NERC

Pursuant to Section 215 of the Federal Power Act, FERC certified NERC as the Electric Reliability Organization responsible for developing mandatory reliability standards, subject to FERC's review and approval. NERC also annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance.

1. Mandatory Reliability Standards

NERC Regional Entity RFC has imposed a mandatory standard for Planning Resource Adequacy Analysis, Assessment, and Documentation for the region that includes Michigan. As the Planning Coordinator for Michigan, MISO is required to annually calculate the planning reserve margin required to meet the one day in ten years benchmark.[12] The standard also requires certain methods for the load forecast and the capacity accreditation for resources and imports.

Like other NERC and Regional Entity standards, this requirement is enforceable with fines of up to $1 million per day per violation. This further ensures MISO conducts robust and standardized resource adequacy planning, and each year MISO extensively documents that its planning methods fully meet this standard.[13]

2. Reliability Assessments

NERC also conducts periodic assessments of reliability in the country, including a summer, winter, and long-term reliability assessment every year. In the seasonal assessments, NERC groups regions into three categories for risk of resource adequacy shortfalls, as shown in the NERC figure below.[14] MISO's categorization as "elevated" risk in this year's NERC Summer Reliability Assessment is the middle of three risk categories, below "high" and above

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[11] *Id.* at 38-39.
[12] NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf
[13] *See, e.g.*, MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 56-60.
[14] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.

"normal." In its 2023[15] and 2024[16] Summer Reliability Assessments, NERC respectively identified 8 and 5 out of 13 U.S. regions as having elevated risk. Despite half of U.S. regions being designated as having elevated risk, there were no resource adequacy shortfalls in either summer.

Table 1: Seasonal Risk Assessment Summary	
Category	**Criteria[1]**
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels; or • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios[2]**
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Figure 1: NERC table showing categories used for regions' seasonal risk

III. There Is No Evidence Consumers Energy, Michigan, or MISO Has a Resource Adequacy Emergency this Summer.

Michigan utility regulators and Consumers Energy have determined that Campbell was not needed to meet resource adequacy needs, a conclusion confirmed by MISO's resource adequacy analysis and capacity market results showing a capacity surplus for this summer. Moreover, NERC's Summer Reliability Assessment does not indicate MISO has a supply emergency.

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[15] NERC, *2023 Summer Reliability Assessment*, (May 2023) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf, at 6.
[16] NERC, *2024 Summer Reliability Assessment*, (May 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, at 6.

A. Michigan

Consumers Energy completed comprehensive reliability and economic modeling in its 2021 IRP, overseen by the Michigan Public Service Commission with robust engagement from stakeholders. As explained above, a cornerstone of this and all IRPs is ensuring resource adequacy needs are met. The utility,[17] the Commission,[18] and other stakeholders concluded that it was more economic and reliable to replace Campbell with a variety of other resources, including by (1) acquiring the nearby 1,200 MW gas-fired Covert Generating Station, which Consumers Energy subsequently purchased in May 2023, and (2) adding nearly 1,600 MW of demand response and energy efficiency by 2025.[19]

Michigan utilities are also bound by the state's Public Act 341 of 2016, which requires them to demonstrate to the Michigan Public Service Commission that they have sufficient generating capacity to meet their capacity obligations. The Commission can impose a state reliability mechanism capacity charge on utilities that fail to meet that requirement. In June 2022, the Commission approved Consumers Energy's demonstration for the 2025/2026 planning year,[20] and more recently Consumers successfully made this demonstration for the 2027/2028 planning year[21] and filed its demonstration for 2028/2029.[22]

Confirming that state and regional officials stand by their determination that the Campbell plant is not needed, the Chair of the Michigan Public Service Commission recently indicated that MISO, Michigan, and Consumers Energy did not ask to keep the Campbell plant online.[23]

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[17] CMS Energy, *Integrated Resource Plan*, (June 2021) available at https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf
[18] Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)
[19] *Id.* at 4 (101 in the pdf).
[20] See the discussion of Case No. U-21099 at Michigan Public Service Commission, *MPSC approves Consumers Energy integrated resource plan settlement agreement, takes additional steps to boost electric capacity*, (June 2022) available at https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp_takes-steps-improve-capacity
[21] Michigan Public Service Commission, *Order*, Case Nos. U-21393 and U-21775, (August 2024) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000005gPyUAAU
[22] Consumers Energy, *Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029*, (February 2025) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000bz8crAAA
[23] C. Brown and H. Stevens, *Coal and Gas Plants Were Closing. Then Trump Ordered Them to Keep Running*, (June 2025) available at https://www.nytimes.com/2025/06/06/climate/trump-coal-gas-plants-energy-emergency.html

B. MISO

Based on the loss of load analysis discussed above, MISO has concluded that it has "surplus capacity" for this summer, without Campbell.[24] The 2025/26 capacity auction yielded summer capacity supplies 2,623 MW or 2.2 percentage points above the summer reserve margin target of 7.9%, which was calibrated to meet the one day in ten years loss of load benchmark.[25] In other words, MISO would still meet this stringent reliability benchmark this summer even if an additional 2,623 MW of additional capacity unexpectedly were unavailable, and retaining Campbell would only increase MISO's already-generous capacity surplus for this summer beyond 4 GW. As noted above, capacity supply above the reserve margin target provides diminishing marginal returns.

The zonal results from MISO's 2025/26 capacity auction also confirm there is no resource adequacy shortfall this summer in Zone 7, which is the MISO footprint in Michigan's Lower Peninsula. Zone 7 has 1.2 GW of supplies above the summer Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.[26]

C. NERC's Summer Reliability Assessment Does Not Indicate a Supply Emergency.

The NERC Summer Reliability Assessment that DOE cites in an attempt to justify the Campbell 202(c) order is based on information reported by MISO and other regional grid operators. Thus, the NERC assessment does not contradict MISO's conclusion that it has a capacity surplus above what it needs to meet its reliability target. In fact, NERC notes that for MISO, "Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level," which is MISO's reserve margin target calibrated to achieve a loss of load risk of one day in 10 years.[27]

NERC including MISO in the "elevated" summer risk category does not indicate a supply emergency. This year's Summer Reliability Assessment identifies four U.S. regions as having elevated risk, plus one region each in Canada and Mexico. As noted above, across the 2023 and 2024 Summer Reliability Assessments NERC identified half of U.S. regions as having elevated risk, yet there were no resource adequacy shortfalls in either summer.

This year's Summer Reliability Assessment finds that MISO has a 24.7% reserve margin, which NERC calculates corresponds to a 9.3% reserve margin with typical generator outage

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[24] MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf at 4.
[25] *Id.* at 3, 4, 37.
[26] *Id.* at 18.
[27] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 12.

rates. NERC's finding of elevated risk only indicates a "Potential for insufficient operating reserves in above-normal conditions."[28] NERC finds that MISO would only see a generation shortfall with a perfect storm of 90th percentile demand (*i.e.*, demand is higher than expected in 9 out of 10 years) at the same time that MISO sees its highest historical rate for generator outages and derates due to "extreme conditions," and even in that worst case scenario it would only have a 1.9% shortfall.[29] By way of comparison, NERC's 2023 and 2024 Summer Reliability Assessments projected MISO would have a 6.9% and 6.3% shortfall under that worst case scenario, respectively, yet NERC still did not designate the risk as "high," and MISO ultimately had more than adequate supplies in both summers.

As explained above, MISO and utility reserve margins are already designed to accommodate wide interannual variability in electricity demand and generator outages, and MISO has calibrated its summer reserve margin to the stringent requirement that it only experience one day of shortfall in 10 years. Moreover, NERC notes that Michigan and the rest of MISO have the lowest risk of any region for seeing above average temperatures this summer.[30]

D. The NERC and MISO resource adequacy studies are likely conservative.

NERC's Summer Reliability Assessment and MISO's loss of load analysis both use conservative assumptions for the availability of imports and renewable output in MISO.

NERC's analysis does not fully account for MISO's ability to import power during periods of need, even though MISO successfully tapped into the supply and demand diversity provided by its neighbors to import more than 13 GW during Winter Storm Uri[31] and 4.5 GW during Winter Storm Elliott.[32] Other studies have documented significant diversity between MISO and its neighbors in the timing of peak demand, lulls in renewable output, and correlated thermal generator outage and derate events, including summer heat waves.[33] These geographic diversity benefits are due to inherent climate and weather diversity, and the fact that extreme heat and cold events are only at their most severe in small geographic areas that move over the course of an event.

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[28] *Id.* at 6.
[29] *Id.* at 10, 16.
[30] *Id.* at 9.
[31] M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) available at https://gridstrategiesllc.com/wp-content/uploads/2024/05/transmission-makes-the-power-system-resilient-to-extreme-weather.pdf, at 7.
[32] M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) available at https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf
[33] A. Brooks, A. Silverstein, and R. Gramlich, *Resource Adequacy Value of Interregional Transmission*, (June 2025) available at https://gridstrategiesllc.com/wp-content/uploads/GridStrategies_RAValueInterregionalTx_250601.pdf; M. Goggin, Z. Zimmerman, and A. Sherman, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) available at https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf

DOE's National Transmission Planning Study documented the geographic diversity phenomenon with a compelling set of maps.[34] Those maps show that during the event when MISO saw the highest demand in the period 2007-2013, the Southwest Power Pool and the Southeast had significantly lower demand. Similar maps in the study show significant diversity in when MISO and its neighbors experience lulls in wind or solar output.[35]

NERC has previously noted that "MISO benefits from significant transfer capacity with neighboring assessment areas…"[36] Data in NERC's 2025 Summer Reliability Assessment documents that these neighboring grid operators have large reserve margin surpluses this summer, which further increases the availability of imports from those regions. NERC projects the summer reserve margin surplus under typical generator outage rates for the Southwest Power Pool at 18.2%, Ontario at 23.4%, PJM at 15.0%, the SERC Central region at 12.7%, and Manitoba at 11.2%.[37] As a result, at least some of those regions are highly likely to have surplus generating resources if MISO experiences periods of high demand or low supply this summer.

When calculating the reserve margin needed to meet the 1 day in 10 year target, MISO's loss of load study also makes conservative assumptions for the availability of imports from other regions. While MISO conducts robust statistical modeling of historical import availability, this analysis is conservative because hours in which MISO was exporting or minimally importing due to a lack of need are included in the dataset, even though MISO likely could have imported or at least reduced exports in those hours if needed.[38]

If there were a true resource adequacy emergency in MISO, a potential solution would be to issue a Section 202(c) order to facilitate interchange with neighboring grid operators. As the MISO independent market monitor[39] and others[40] have documented, inefficient pricing of market transactions along MISO's seams with neighboring grid operators can interfere with the efficient flow of power during shortage events. DOE could work with MISO and other stakeholders to improve the efficient flow of power across MISO's seams, improving the availability of imports during periods of peak need.

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[34] DOE, *National Transmission Planning Study: Chapter 2*, (October 2024) available at https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf, at 53.
[35] *Id.* at 51 and 52.
[36] NERC, *2024 Long Term Reliability Assessment*, (December 2024) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf, at 44.
[37] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.
[38] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 33.
[39] Potomac Economics, *2023 State of the Market Report*, (June 2024) available at https://cdn.misoenergy.org/2023%20State%20of%20the%20Market%20Report636641.pdf, at xiv-xv.
[40] J. Pfeifenberger and N. Bay, *Intertie Optimization: Efficient Use of Interregional Transmission (Update)*, (April 2024) available at https://www.brattle.com/wp-content/uploads/2024/04/Intertie-Optimization-Efficient-Use-of-Interregional-Transmission-Update.pdf

If DOE's claim of resource adequacy risk in MISO were true, facilitating interchange with neighboring grid operators would be more appropriately tailored to address the risk. This is because loss of load probability is concentrated into a narrow slice of hours on a small number of days when high demand coincides with low supply. Increased interchange can occur during just those hours, tapping into diversity in the timing of peak need between MISO and its neighbors. In contrast, retaining the Campbell coal plant for the entire summer is not well-tailored for meeting DOE's claimed emergency.[41]

MISO and NERC also appear not to have accounted for the fact that low wind speed events are negatively correlated with low solar output events. For example, wind speeds tend to be low during high pressure heat dome events, which tend to cause high solar output because there are fewer clouds during such events. Conversely, stormy conditions that result in reduced solar output due to clouds tend to be correlated with high wind output. As NERC notes, MISO has over 31 GW of wind and 18 GW of solar, so one resource can make up for shortfalls of the other.[42] As noted above, there is also significant diversity in when MISO and its neighboring regions experience lulls in renewable output. MISO meteorologists have also "projected normal to above-normal wind generation" for this summer.[43]

<u>IV. Consumers Energy May Need to Buy Coal to Comply with DOE's Order.</u>

The DOE data shown below indicate that coal supplies at the plant appear to have been drawn down in advance of its anticipated retirement, with enough coal remaining onsite as of the end of March 2025 to operate the plant for only about two to three weeks.[44] The DOE data indicate the plant is supplied via rail deliveries from a coal mine in Wyoming.[45]

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[41] As DOE's Campbell order notes, "FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts." U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf, at 2.

[42] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 16.

[43] MISO, *2025 Summer Readiness Workshop*, (May 2025) available at https://cdn.misoenergy.org/20250508%20Summer%20Readiness%20Workshop%20Items%2002-04%20Presentation695282.pdf, at 17.

[44] DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/, with monthly stocks calculated by taking coal stock data as of December 2023 and then subtracting monthly consumption and adding monthly deliveries.

[45] *Id.*

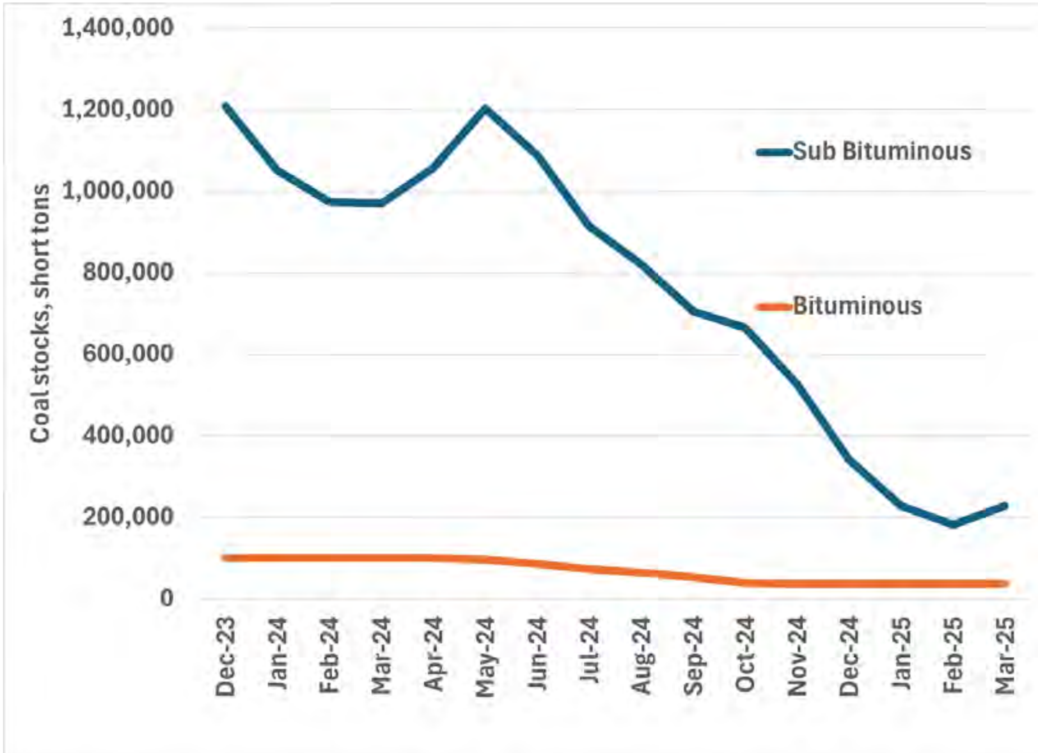

Figure 2: Coal supplies at Campbell, per DOE data

V. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

In the course of that work, Michael has co-authored more than one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; published academic articles and conference presentations on renewable integration, transmission, and policy; and been elected to the Standards, Operating, and Planning Committees of NERC. He graduated with honors from Harvard University. His recent publications are available at https://gridstrategiesllc.com/reports/.

VI. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, available at https://campd.epa.gov/data/custom-data-download

-NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

-NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

-Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)

DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/

Michael Goggin

Michael Goggin
Vice President
Grid Strategies, LLC

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 3

Powers June Decl.

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received “Engineer of the Year” awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity (“NEESA”) office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a “Productivity Award of Excellence” from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps shore installation of coal-fired power plants in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. For example, in 2022 I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal that was justified in part on the company's belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the operation of, and control of pollution from, coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas.

7. I am very familiar with "peaking" units that are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas

turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") May 23, 2025 order regarding Consumers Energy Company's ("CECo") J.H. Campbell coal-fired power plant (Order No. 202-25-3) ("Order").

9. The J.H. Campbell coal-fired power plant ("Campbell") consists of three coal-fired generating units. The in-service dates for Units 1, 2, and 3 are 1962, 1967, and 1980 respectively.[1] The nameplate capacity for Unit 1 is 265.2 MW; for Unit 2 is 378.8 MW; and for Unit 3 is 916.8 MW.[2] Under CECo's 2021 integrated resource plan ("IRP"), which was approved with modifications by the Michigan Public Service Commission ("Michigan PSC") in 2022, the Campbell units were scheduled to retire on or before May 31, 2025.

10. I was asked by Earthjustice to develop an opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts. A list of materials I reviewed in developing my opinion is attached (Attachment B).

11. While there may be alternatives to Campbell available to DOE to address the circumstances DOE describes in the Order, I do not opine on these alternatives. I also do not opine on the claimed energy emergency described in the Order.

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[1] Michigan PSC Case No. U-21585, Direct Testimony of Richard T. Blumenstock on Behalf of CECo, p. 7, Tbl. 1 (May 2024).

[2] EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), https://www.eia.gov/electricity/data/eia860m/ (showing nameplate capacity).

A. <u>The extent to which Campbell can operate reliably beginning June 1, 2025</u>

12. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of June 2025.[3] This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions.

13. Even before the scheduled retirement date of May 31, 2025, Campbell suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.[4] In contrast, Campbell Units 1-3 had forced outage rates in 2024 of 14.84 percent, 48.07 percent, and 19.25 percent, respectively[5]—well above the average coal unit forced outage rate. The forced outage rates in 2023 were similarly high: Units 1-3 had forced outage rates of 18.66 percent, 57.32 percent, and 22.41 percent, respectively.[6]

14. "Availability" is a measure of the percent of time a unit is not in planned or forced outage and is available to generate electricity. Campbell has lower availability than coal units of comparable size. When CECo compared the availability of the Campbell units in 2019-2023 to similarly sized and fueled generating units, the company found that "[t]he availability of Campbell Units 1, 2, and 3 were all below the five-year comparisons."[7]

15. The nature of the Unit 1-3 outages in 2023 and 2024 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Unit 1-3 outages by description and duration in 2024 and 2023, respectively. The long outages on Units 1 and 2, and the types of

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[3] CECo filed testimony regarding Campbell on June 2, 2025, in its most recent rate case before the Michigan PSC.
[4] NERC, *2024 State of Reliability*, p. 59 (June 2024).
[5] Michigan PSC Case No. U-21424, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-15 (Mar. 2025).
[6] Michigan PSC Case No. U-21258, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-14 (Mar. 2024).
[7] U-21424, Hoffman Direct Testimony, p. 22 & Ex. A-16.

failures, are the predictable result of old equipment, no capital investment, and minimal maintenance.

Table 1. Longest 2024 Outages by Type, Units 1-3 - Description and Duration[8]

Unit	Outage description	Total duration (hours)
1	• degraded governing valve (3 outages) • worn leaking superheater tube (1 outage)	911 491
2	• obsolete boiler feedwater pump failure (1 outage) • degraded valve(s) malfunction (3 outages) • worn equipment leaks, various (4 outages)	1,417 1,723 854
3	• worn/failed turbine turning gear[9] (1 outage) • worn tube leak (1 outage)	1,104 356

Table 2. Longest 2023 Outages by Type, Units 1-3 - Description and Duration[10]

Unit	Outage description	Total duration (hours)
1	• worn leaking valve and superheater tube (2 outages)	661
2	• obsolete boiler feedwater pump failure (4 outages) • worn equipment leaks (3 outages)	3,445 571
3	• worn leaking boiler/superheater tubes (3 outages) • worn/vibrating turbine bearings (1 outage)	1,857 426

16. In my professional opinion, Campbell will continue to degrade in 2025 due to the continued lack of capital investment and minimal major maintenance spending.

17. CECo dramatically reduced capital and major maintenance spending on Units 1-3 following the IRP that established a May 2025 retirement date. CECo reduced its capital spending on the units in the 2022-2025 period by approximately 91 percent compared to the amount the company projected to spend in the same period if Units 1-2 operated until 2031 and Unit 3 operated until 2039 (the retirement dates CECo originally proposed in its IRP). Likewise, CECo reduced its major maintenance spending on the units in the 2022-2025 period by 62-78

[8] U-21424, Hoffman Direct Testimony, Ex. A-11.
[9] *Ibid.*, Ex. A-13. The stated scope of the turbine turning gear repair was to "[f]abricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025."
[10] U-21258, Hoffman Direct Testimony, Ex. A-10.

percent (approximately 72% total across all three units). The reductions in capital and major maintenance spending are summarized in Table 3.[11]

Table 3. Reductions in CECo Capital and Major Maintenance Spending on Campbell Units 1-3, 2022-2025

Capital spending	Pre-IRP projected spend 2022-25 ($MM)	Post-IRP actual/projected spend 2022-25 ($MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

18. Some of the capital and major maintenance projects that CECo cancelled in 2022-2025 were reliability projects, while others were air emission control system projects. Regarding the reliability projects that CECo originally planned to carry out (before deciding to retire Units 1-3 in May 2025), CECo likely believed they were necessary to maintain adequate unit reliability and that failure to carry out the projects could compromise that reliability. But CECo then determined that those projects were unnecessary with the May 2025 retirement. Therefore, it is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

19. A detailed listing of the 2022-2025 capital projects that CECo projected carrying out before deciding to retire the units in May 2025 is shown in the left-hand column of Tables 4a (Units 1 and 2) and 4b (Unit 3).[12] As can be seen from the middle column in these tables,[13] CECo did not carry out most of those projects.

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[11] Table 3 summarizes the information presented in Tables 4a, 4b, 5a, and 5b, which are based on CECo filings with the Michigan PSC.

[12] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 13-18 (Oct. 2021).

[13] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-12 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case Nos. U-21389 (May 2023), U-21585 (May 2024), and U-21870 (June 2025).

20. Table 4a compares (i) the capital projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with (ii) those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by two-thirds on Units 1 and 2 in 2022, from the proposed $12.6 million to $4.1 million. No capital spending occurred in 2023-2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled capital projects with a direct impact on unit reliability include, among others, partial replacement of the Unit 1 superheat outlet pendant and replacement of the Unit 2 burner assemblies and horizontal reheat system.

Table 4a. Units 1&2 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $12,556,500 $7,300,000 at Campbell Unit 1, including: • PJFF Bag Replacement ($1,578,000) • Superheat Outlet Pendant – partial replacement ($3,490,000) • Five additional projects totaling $2,232,000 $5,256,500 at Campbell Unit 2, including: • Catalyst Management ($1,120,000) • Replace Burner Assemblies ($1,350,000) • Six additional projects totaling $2,786,500	**2022 actual expenditure: $4,067,000** The 2022 actual capital expenditure primarily consisted of two projects, both on Unit 1: air preheater baskets and seals ($1,819,000), and pulse jet fabric filter bags ($1,040,000).	**$8,489,500**
2023 projected spend (in 2021): $16,686,700 $7,214,680 at Campbell Unit 1, including: • PJFF Filter Bag Replacement ($1,514,100) • Replace Air Preheater Baskets and Seals ($1,113,400) • Distributed Control System and Simulator Upgrade ($1,500,000) • Ashpit Rebuild ($1,000,000) • Twelve additional projects totaling $2,087,180 $9,472,020 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($5,053,000) • SCR Reactor Catalyst Replacement ($2,000,000) • Nine additional projects totaling $2,419,020	**2023 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,479,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0.	**$16,686,700**
2024 projected spend (in 2021): $21,005,000 $9,753,000 at Campbell Unit 1, including: • Replace Burners Corner 1-8 ($2,700,000) • Replace Air Preheater Baskets and Seals ($1,137,100) • Boiler Component Replacement ($3,000,000) • Balance of Plant Equipment Replacement ($1,500,000) • Six additional projects totaling $1,415,900 $11,252,000 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($7,952,000) • Distributed Control System and Simulator Upgrade ($1,500,000) • Four additional projects totaling $1,800,000	**2024 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,510,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.[14]	**$21,005,000**
2025 projected spend (in 2021): $10,350,000 $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually $7,800,000 at Campbell Unit 2, including: • Replace turbine right side Reheat Stop Valve body ($1,850,000) • Boiler Component Replacement ($3,000,000) • Five additional projects totaling $2,950,000	**2025 projected expenditure: $0** CECo projected no capital expenditures at Unit 1 or Unit 2 in 2025.	**$10,350,000**
	TOTAL	**$56,531,200**

[14] *See* U-21585, Blumenstock Direct Testimony, p. 62.

21. Table 4b compares the capital projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by more than half on Unit 3 in 2022, from a proposed $17.1 million to $7.9 million, and dropped almost entirely in 2023, from a proposed $20.5 million to less than $0.5 million. No capital spending occurred in 2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled Unit 3 capital projects with a direct impact on unit reliability include, among others, complete coal mill overhauls, boiler wall panel replacements, and fuel handling repairs.

Table 4b. Unit 3 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $17,125,333 • PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601) • SCR Reactor Catalyst Management ($1,866,200) • Complete Mill Overhauls ($1,264,800) • Replace CO-O2 Monitors ($967,400) • Design and Install New Large Particle Ash Screen ($1,485,100) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Sixteen additional projects totaling $6,047,032	**2022 actual expenditure: $7,935,000** The 2022 actual capital expenditure included three projects: air compressor replacement ($1,207,000); selective catalytic reduction catalyst management ($1,196,000); and diesel generator controls ($1,172,000). The actual expenditure represented about 46 percent of the pre-IRP projection.	**$9,190,333**
2023 projected spend (in 2021): $20,478,187 • PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331) • Complete Mill Overhauls ($1,295,300) • Design and Install New Large Particle Ash Screen ($1,008,700) • Secondary Air Heater basket & seal replacement ($2,425,000) • High Pressure Feedwater Heater 8A replacement ($5,039,800) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Seventeen additional projects totaling $6,954,257	**2023 actual expenditure: $456,000** The actual capital expenditure represented about 2 percent of the pre-IRP projection.	**$20,022,187**
2024 projected spend (in 2021): $33,395,569 • SCR Reactor Catalyst Management ($1,959,510) • Turbine Drain Modifications ($2,535,000) • Superheat Terminal Drain Replacement ($3,023,100) • Replace Boiler Sidewall Panels ($2,425,000) • Replace Boiler Front And Rear Wall Panels ($2,482,900) • Secondary Air Heater basket & seal replacement ($1,562,000) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Cell Construction and Permitting ($5,482,830) • and twenty-one additional projects totaling $12,425,229	**2024 actual expenditure: $0** The precise value reported in Consumers' filing is negative (-$1,264,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.	**$33,395,569**
2025 projected spend (in 2021): $14,512,045 • GSU Replacement ($6,485,045) • SCR Reactor Catalyst Management ($3,000,000) • AQCS Equipment repair/replacement ($1,000,000) • Cell Construction and Permitting ($2,000,000) • and four additional projects totaling $2,027,000	**2025 projected expenditure: $0** CECo projected no Unit 3 capital budget in 2025.	**$14,512,045**
	TOTAL	**$77,120,134**

22. A detailed listing of the 2022-2025 major maintenance projects that CECo projected carrying out before deciding in 2022 to retire the units in May 2025 is shown in the left-hand column of Tables 5a (Units 1 and 2) and 5b (Unit 3).[15] As can be seen from the middle column in these tables,[16] CECo did not carry out most of those projects.

23. Table 5a compares the major maintenance projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 62 percent across 2022-2025, from a proposed total of $14.4 million to $5.5 million. CECo does not specify the nature of most of its major maintenance projects in its rate case filings. However, one cancelled major maintenance project with a direct impact on unit reliability is the Unit 2 turbine valve inspection project.

[15] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 28-30 (Oct. 2021).
[16] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-41 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case No. U-21389 (May 2023) and Ex. A-43 to witness Blumenstock's testimony in Case Nos. U-21585 (May 2024), and U-21870 (June 2025).

Table 5a. Units 1&2 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $3,537,000 • Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000) • Thirteen additional projects totaling $2,289,000	**2022 actual expenditure: $3,307,000** The 2022 actual maintenance expenditure was slightly less than the Unit 1&2 maintenance budget projected by CECo in 2021.	**$230,000**
2023 projected spend (in 2021): $2,905,000 • Covering 10 projects	**2023 actual expenditure: $1,054,000** The 2023 actual maintenance expenditure was approximately one-third the Unit 1&2 maintenance budget proposed for 2023 by CECo in 2021.	**$1,851,000**
2024 projected spend (in 2021): $3,405,167 • Covering 12 projects	**2024 actual expenditure: $903,000** The 2024 actual maintenance expenditure was approximately 27 percent of the Unit 1&2 maintenance budget proposed for 2024 by CECo in 2021.	**$2,502,167**
2025 projected spend (in 2021): $4,569,000 • Campbell 2 Turbine Valve Inspection ($1,300,000) • Seven additional projects totaling $3,269,000	**2025 projected expenditure:**[17] **$268,000** The 2025 projected maintenance expenditure was approximately 6 percent of the Unit 1&2 maintenance budget proposed for 2025 by CECo in 2021.	**$4,301,000**
	TOTAL	**$8,884,167**

[17] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Units 1&2 as well as the additional months those units would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

24. Table 5b compares the major maintenance projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 78 percent across 2022-2025, from a proposed total of $23.5 million to $5.1 million. CECo does not specify most of its major maintenance projects in its rate case filings. However, as discussed in more detail below, one cancelled major maintenance project with a direct impact on unit reliability is the $7.9 million Unit 3 turbine overhaul project. The project was originally scheduled to take place in 2024. The turbine failed in April 2024 resulting in a 46-day forced outage.[18]

[18] *See infra* Tbl. 1.

Table 5b. Unit 3 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $4,208,040 • Boiler Feed Pump Turbine Inspection ($1,680,000) • Fourteen additional projects totaling $2,528,040	**2022 actual expenditure: $3,196,000** The 2022 actual maintenance expenditure was sufficient to do about 75 percent of the Unit 3 maintenance projects budgeted for 2022 by CECo in 2021.	**$1,012,040**
2023 projected spend (in 2021): $2,523,970 • Covering 12 projects	**2023 actual expenditure: $995,000** The actual expenditure represented about 40 percent of the pre-IRP projection.	**$1,528,970**
2024 projected spend (in 2021): $12,954,250 • Campbell 3 Turbine Overhaul ($7,931,350) • Campbell 3 Boiler Chemical Cleaning ($1,429,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000) • Campbell 3 Periodic Outage Maintenance ($933,100) • Eight additional projects totaling $1,660,800	**2024 actual expenditure: $591,000** The 2024 projected actual maintenance expenditure was sufficient to do about 5 percent of the Unit 3 maintenance projects budgeted for 2024 by CECo in 2021. The highest cost proposed 2024 project, the Campbell 3 Turbine Overhaul ($7,931,350), was not carried out. The turbine failed in April 2024 resulting in a 46-day forced outage.	**$12,363,250**
2025 projected spend (in 2021): $3,810,600 • Campbell 3 Turbine Valve Inspection ($1,200,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000) • Six additional projects totaling $1,410,600	**2025 projected expenditure:**[19] **$277,000** The actual expenditure represented about 7 percent of the pre-IRP projection.	**$3,533,600**
	TOTAL	**$18,437,860**

[19] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Unit 3 as well as the additional months that unit would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

25. It is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

26. Moreover, Campbell Units 1 and 2 were built in the 1960s. Units 1 and 2 are beyond both a typical coal unit economic design life of 30-40 years and a typical operational lifetime of 40-50 years.[20,21]

27. Replacement parts are not readily available or do not exist for Units 1 and 2, as described by CECo witness Hoffman: "Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist."[22]

28. CECo witness Blumenstock states that CECo discontinued capital investment in Units 1-3 in 2023 and is only doing sufficient maintenance to keep Units 1-3 operable through May 2025: "The Company does not plan to invest any capital in the Campbell units during the bridge period [2024 and early 2025] or test year . . . [T]he Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025."[23] Witness Blumenstock also indicates that Unit 1 would be retired early, on April 1, 2025.[24]

29. In my professional opinion, witness Blumenstock is describing CECo's transition from a preventative capital investment and maintenance structure, intended to maintain the

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[20] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).
[21] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).
[22] U-21424, Hoffman Direct Testimony, p.6.
[23] U-21585, Blumenstock Direct Testimony, p. 62.
[24] *Ibid*., p. 20.

Campbell units' long-term reliability, to a reactive, "fix it if breaks" approach to operating Units 1-3. CECo's objective shifted from maintaining long-term reliability to keeping the units operating—to the extent possible with little or no spending—*up until* May 31, 2025 *and no longer.* CECo's objective was *not* to achieve the high level of Unit 1-3 reliability that would be necessary for the units to ramp up and work reliably under emergency demand conditions.

30. A case in point is the cancelled $7.9 million Unit 3 turbine overhaul project that was originally scheduled for 2024.[25] In late April 2024, the Unit 3 turbine suffered a turning gear failure that resulted in a 1,104-hour (46 day) forced outage.[26] The turbine turning gear was repaired to achieve the limited objective of allowing Unit 3 to continue to operate until the planned retirement in (May) 2025.[27] It is reasonable to assume that the turning gear failure would not have occurred if the Unit 3 turbine had already been overhauled. This failure incident calls into question how many other Unit 3 components are vulnerable to near-term failure due to lack of investment and preventative maintenance by CECo. Given the limited maintenance, it would be unreasonable for DOE to assume that Unit 3 can run much longer without CECo doing a substantial amount of deferred maintenance.

31. While it is not possible based on publicly available information to put an exact price tag on the cost of ensuring that Campbell could reliably operate at full capacity, CECo cancelled **approximately $161 million** in planned capital and major maintenance projects at Campbell over the past four years ($133.6 million in capital projects; $27.3 million in major maintenance projects). It is reasonable to assume that much of this investment was necessary to ensure continued, nominally reliable operation of Campbell. It is also reasonable to assume that

[25] U-21090, Kapala Revised Direct Testimony, p. 29.
[26] U-21424, Ex. A-11 to Hoffman Direct Testimony.
[27] *Ibid*., Ex. A-13.

some of this investment was necessary to ensure compliance with environmental requirements, as discussed more below. Those capital and major maintenance investments are what *CECo determined* in 2021 that it would need to spend on a year-to-year basis to operate the Campbell units reliably and in conformance with environmental requirements in 2022-2025, if these units were to continue to operate past May 2025 (i.e. until 2031 for Units 1 and 2 and until 2039 for Unit 3).

B. <u>Whether Campbell can operate effectively as a peaking unit</u>

32. In my opinion, Campbell cannot operate effectively as a peaking unit that would be dispatched with only a few hours of notice to meet an extreme demand condition.

33. Coal units generally, and Campbell's three units specifically, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, round-the-clock operation.[28] Coal units started "cold" (room temperature) typically take approximately 12 hours to reach full load operation.[29] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[30] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[31]

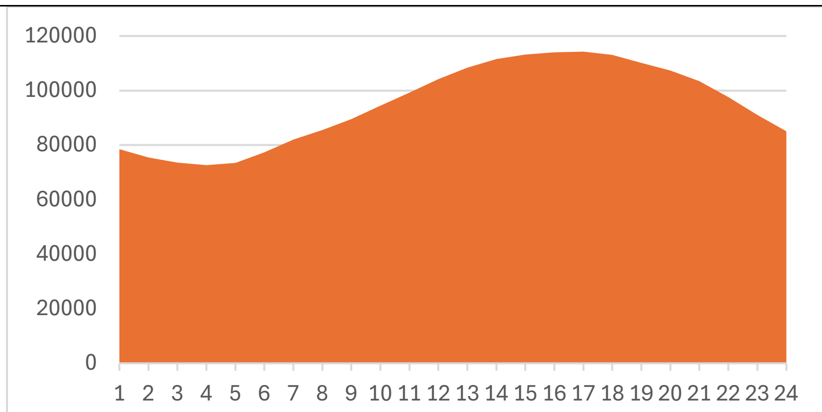
34. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need

[28] U-21258, Hoffman Direct Testimony, pp. 4-5.
[29] IEA Clean Coal Centre, *Increasing the flexibility of coal-fired power plants*, p. 26 (Sept. 2014).
[30] NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . . .").
[31] General Electric, *Get to know the LM6000* (webpage) (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").

substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

35. Grid demand often increases rapidly on peak demand days. MISO may have only a few hours of notice that an extreme peak demand day is developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the period immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a 24-hour demand curve for the MISO control area on the high demand summer day of September 5, 2023.[32] MISO actual demand was rising as fast as 5,000 MW per hour during the day, adding the equivalent of Campbell's 1,561 MW capacity every 20 minutes to meet demand.

Figure 1. MISO 24-hour demand curve (MW), September 5, 2023



36. Bringing Campbell from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[33] The total nameplate capacity of Campbell Units 1-3 is 1,561 MW. Therefore, the

[32] Figure 1 was developed using data from U.S. EIA, csv dataset, "MISO_load-temp_hr_2023" (accessed June 13, 2025).
[33] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, p. 16 (Jan. 2020).

estimated cost to start up Campbell from a cold start condition would be approximately $650,000. (1,561 MW × $417 per MW = $650,937).

37. Alternatively, instead of starting cold, CECo could be forced to run Campbell for hours unnecessarily solely to be prepared for a potential near-term high-peak demand. That approach would be expensive and polluting.

C. **<u>Easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts</u>**

38. In my opinion, for DOE's order to be consistent with environmental requirements, CECo must demonstrate, prior to restarting Units 1-3, that (1) the pulse jet fabric filters on Units 1-3 are in sound, leak-free condition, and (2) the SCRs on Units 2 and 3 have sufficient remaining catalyst life to adequately control NO_x emissions.

39. As noted above, some of the capital and major maintenance projects cancelled in 2022-2025 were air emission control system projects. Cancelled capital projects with a direct impact on maintaining environmental compliance included, among others, PJFF filter bag(s) replacement on Unit 1 (for particulate/opacity control); SCR reactor catalyst replacement on Unit 2 (for nitrogen oxide control); and replacement of PJFF filter bag(s), "cleaning air manifold," and SCR reactor catalyst on Unit 3.[34] These projects were planned likely because CECo believed they were necessary to maintain adequate air emission control system performance and that failure to carry out the projects could compromise that performance.

40. Table 6 shows the multiple air emission control system capital projects that were cancelled in 2022-2025. The implications of these cancelled air quality control system projects are: (1) degraded fabric filter performance on Units 1 and 3, potentially resulting in particulate

[34] *See infra* Tables 4a and 4b.

and/or opacity exceedances, and (2) degraded performance of nitrogen oxide (NO_x) control systems (SCR) on Units 2 and 3, potentially resulting in NO_x exceedances. Degraded fabric filter performance, caused by torn or improperly secured filter bags, could lead to elevated levels of opacity and particulate emissions. A degraded SCR catalyst could lead to poor NO_x conversion and elevated NO_x emissions at the stack.

Table 6. Cancelled 2022-2025 Campbell Unit 1-3 air quality control capital projects

Year	Unit	Project[35]	Budget ($)
2022	2 3	• (SCR) catalyst management • Fabric filter bag(s) & cleaning air manifold replacement	1,120,000 3,994,601
2023	1 2 3	• Fabric filter bag replacement • SCR reactor catalyst replacement • Fabric filter bag(s) & cleaning air manifold replacement	1,514,100 2,000,000 3,263,331
2025	3	• SCR reactor catalyst management • Air quality control system (AQCS) equipment repair/replacement	3,000,000 1,000,000

41. In light of these cancelled projects, DOE should require that CECo demonstrate that the Campbell Unit 1-3 pulse jet fabric filters are currently leak free prior to authorizing further operation. DOE also should require that CECo provide records demonstrating that the catalysts in the Units 2 and 3 SCRs have sufficient remaining useful life to reasonably assure compliance with NO_x limits.

42. It is my opinion that DOE should require verification of the good working order of the Unit 1-3 air emission control systems before authorizing Campbell to operate under extreme demand conditions. DOE should also require that any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO_2 that occur during operation of Units 1-3, as registered on the continuous opacity, NO_x, or SO_2 monitors installed on each unit, be shut down.

[35] *See* U-21090, Kapala Revised Direct Testimony; U-21389, Blumenstock Direct Testimony, Ex. A-12 (not listed as carried-out); U-21585, Blumenstock Direct Testimony, A-12 (not listed as carried-out).

43. It is also my opinion that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm.

44. Any air emissions that result from running Campbell would not occur if the plant is retired. Additionally, according to its NPDES wastewater discharge permit, Campbell is cooled with ~1 billion gallons per day of Lake Michigan water in a once-through cooling configuration (NPDES permit). Therefore, the plant will use up to 1 billion gallons per day if called to operate. That is a potentially significant impact on Lake Michigan marine fauna that does not occur if Campbell is retired. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is another impact that would not occur if Campbell is retired.

45. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp time and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 15th day of June 2025, in San Diego, California.

Bill Powers, P.E.

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ºF and 13 ºF were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ºF and 13 ºF. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ºF. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

Non-Wires Alternatives to Transmission Lines

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

Combustion Equipment Permitting, Testing and Monitoring

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County. Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District. Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling. Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle “repower” project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide “cap.” Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM. Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion (SCONO$_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 °F) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 °F and 20 °F were evaluated. The annualized cost of the fin-fin air-cooler with a 20 °F approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

List of reviewed materials

1. U.S. Energy Information Administration, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), https://www.eia.gov/electricity/data/eia860m/.

2. U.S. EIA, Form EIA-923 detailed data with previous form data (EIA-906/920) (Apr. 2025), https://www.eia.gov/electricity/data/eia923/.

3. U.S. EIA, csv dataset, "MISO_load-temp_hr_2023" (accessed June 13, 2025).

4. Michigan PSC Case No. U-21090, Revised Direct Testimony and Exhibits of Norman J. Kapala on Behalf of Consumers Energy Company (Dec. 2021)

5. Michigan PSC Case No. U-21389, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2023)

6. Michigan PSC, Case No. U-21258, Direct Testimony and Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2024).

7. Michigan PSC Case No. U-21585, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2024)

8. Michigan PSC, Case No. U-21424, Direct Testimony and Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2025).

9. Michigan PSC Case No. U-21870, Direct Testimony and Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (June 2025)

10. M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics* (2022).

11. International Energy Agency, *The Role of CCUS in Low-Carbon Power Systems* (2021).

12. NERC, 2024 State of Reliability (June 2024).

13. International Energy Agency, *Increasing The Flexibility of Coal-Fired Power Plants* (Sept. 2014).

14. NERC, *Energy Storage: Overview of Electrochemical Storage* (Feb. 2021), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf.

15. General Electric, *Get to know the LM6000* (2025) https://www.gevernova.com/gas-power/products/gas-turbines/lm6000.

16. National Association of Regulatory Utility Commissioners ("NARUC"), *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan. 2020).

17. Energy Innovation, *Coal Power 28 Percent More Expensive in 2024 Than in 2021* (June 5, 2025)

18. Campbell National Pollutant Discharge Elimination System Permit No. MI000142 (Oct. 2021)

19. Campbell Renewable Operating Permit No. MI-ROP-B2835-2020b and Permit to Install (MI-PTI-B2835-2020b)

20. Air permitting documents uploaded to the Michigan Department of Environment, Great Lakes, and Energy ("EGLE") webpage for Campbell between May 28, 2025 and June 6, 2025 (available at https://mienviro.michigan.gov/nsite/map/results/detail/-977712189711639421/documents)

    a. PM and HCI 40 CFR 63 Subpart UUUUU Test Protocol EUBOILER1 (uploaded May 28, 2025)

    b. Air Quality Test Observation Report (uploaded May 29, 2025)

    c. Air Quality Test Observation Form (uploaded June 3, 2025)

    d. Hg CEMS Relative Accuracy Test Audit Test Protocol EUBOILER1 (uploaded June 5, 2025)

    e. CEMS Relative Accuracy Test Protocol EUBOILER1 (uploaded June 6, 2025)

    f. Two letters approving Protocol for Emissions Testing (both uploaded June 6, 2025)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 4

DOE Campbell Memorandum

Department of Energy
Washington, DC 20585

May 23, 2025

MEMORANDUM FOR THE SECRETARY

FROM: ALEX FITZSIMMONS
DIRECTOR
OFFICE OF CYBERSECURITY, ENERGY SECURITY, AND EMERGENCY RESPONSE (CESER)

SUBJECT: **ACTION:** Decision on an Order, Pursuant to Section 202(c) of the Federal Power Act for J.H. Campbell Power Plant

ISSUE: Heading into the summer months, the Midcontinent Independent System Operator (MISO) faces potential tight reserve margins, particularly during periods of high demand or low generation resource output. Upcoming planned generation retirements contribute to these tight reserve margins, including the planned retirement of the 1,560 MW J.H. Campbell ("Campbell") coal-fired power plant in West Olive, Michigan. As such, staff of the U.S. Department of Energy (DOE) have prepared an emergency order, pursuant to section 202(c) of the Federal Power Act (FPA), to help address potential generation shortfalls in the summer months.

The order directs MISO, in coordination with Consumers Energy ("Consumers"), to take all measures necessary to ensure that the Campbell Plant is available to operate and to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Although the Campbell Plant is owned and operated by Consumers, MISO is the balancing authority for the region and is responsible for dispatching generation. The order can be issued for up to 90 days and can subsequently be renewed in additional 90-day increments to address the ongoing emergency. Under the FPA, the DOE is required to consult with the Environmental Protection Agency (EPA) on all renewals.

BACKGROUND ON AUTHORITY UNDER SECTION 202(c): Section 202(c) of the FPA[1] allows the Secretary of Energy to order temporary interconnections of facilities or the production and delivery of electricity to resolve emergencies, and actions necessary to comply with these orders will not be found to violate Federal, state, or local environmental laws or regulations. Section 202(c) applies to any entity that owns or operates electric power generation, transmission, or distribution facilities. 202(c) orders typically order either temporary transmission interconnections or allow specific generators to operate beyond the limits that would otherwise be allowed under environmental regulations.

[1] Section 202(c) can be found at 16 U.S.C. § 824a(c), which is available here: https://www.law.cornell.edu/uscode/text/16/824a

BACKGROUND ON ENERGY EMERGENCY: The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025.[2] In its assessment, NERC notes that "Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output." In particular, the retirement of generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the period of highest capacity shortfall for MISO will occur in August.

Multiple generation facilities located in Michigan have retired in recent years. MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" and that the results "demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance."[3]

The results reinforce the need to increase capacity during the 2025 summer peak to address the emergency that exists. In addition, demand is expected to grow with new large load additions. According to the Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired [in Michigan] and no new coal-fired facilities are planned."[4] Additionally, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned. The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022."[5] Indeed, the Palisades nuclear power plant is now scheduled to restart in Fall 2025, underscoring the importance of thermal generation to the Michigan region and the need to reevaluate planned closures to address increasing demand. Palisades will not be available during the peak demand period this summer.

SENSITIVITIES: Consumers announced in 2021 that it planned to "speed closure" of Campbell in 2025, which is several years before the end of its scheduled design life.[6] Since then, MISO and Consumers have incorporated the planned retirement into their supply forecasts and taken action to mitigate the impact of the plant's shutdown. This includes Consumers' recent purchase of a 1,200 MW natural gas power plant in Covert, Michigan, although the NERC Assessment still anticipates tight reserve margins.

Past the planned retirement date of May 31, Consumers has ended its contracts for coal procurement, coal delivery, and power plant staffing and may face challenges with addressing these issues on short notice. The order provides reasonable last-minute contract extensions for fuel and operations, if feasible.

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[2] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[3] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf
[4] https://www.eia.gov/state/print.php?sid=MI
[5] https://www.eia.gov/state/print.php?sid=MI
[6] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

POLICY IMPACT: None.

URGENCY: To address the ongoing energy emergency and minimize the continued risk of power outages, the order needs to be issued as soon as possible. The plant is slated to close on May 31, 2025.

RECOMMENDATION:

- **Concurrence on 202(c) Order for the J.H. Campbell Power Plant:**
    - Recommendation: That you approve the order pursuant to section 202(c) of the Federal Power Act related to the generation system.

APPROVE: CAW DISAPPROVE: _____ NEEDS DISCUSSION: _____ DATE: 5/23/25

Attachments:

1. 202(c) order for the J.H. Campbell Power Plant

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 5

DOE Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 6

DOE Order No. 202-17-4
Summary of Findings

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it “agrees with the Renewal Application and will operate in accordance with its provisions.” Further, Dominion acknowledged that a 202(c) order “is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula.” The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM’s renewal request. On September 13, 2017, the Department received an answer to Sierra Club’s comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part, outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-7
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 7

DOE Order No. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 8

Cooke Email to Alle-Murphy

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy

Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 9

Order Approving Campbell Settlement Agreement and Settlement Agreement

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	)	Case No. U-21090

At the June 23, 2022 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Tremaine L. Phillips, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

On June 30, 2021, Consumers Energy Company (Consumers) filed an application, together with supporting testimony and exhibits, pursuant to: (1) Section 6t of Public Act 341 of 2016 (Act 341), MCL 460.6t; (2) the November 21, 2017 order in Case No. U-18418, Exhibit A, which approved the Michigan Integrated Resource Planning Parameters; (3) the December 20, 2017 order in Case Nos. U-15896 *et al*., Exhibit A, which approved the Integrated Resource Plan (IRP) Filing Requirements; and (4) the February 18, 2021 order in Case Nos. U-20633 *et al*., which adopted additional modeling scenarios to assist in achieving the objectives of Executive Directive 2020-10 (ED 2020-10) and Governor Gretchen Whitmer’s MI (Michigan) Healthy Climate Plan.

On July 22, 2021, a prehearing conference was held before Administrative Law Judge Sally L. Wallace (ALJ). Intervenor status was granted to the Michigan Environmental Council, Natural

Resources Defense Council, Inc., and Sierra Club (collectively, MNS); the Michigan Department of Attorney General (Attorney General); the Great Lakes Renewable Energy Association, Inc. (GLREA); the Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar (collectively, the Clean Energy Organizations (CEOs)); Hemlock Semiconductor Operations LLC (HSC); Cadillac Renewable Energy, LLC, Genesee Power Partner Limited Partnership, Decker Energy-Grayling, Inc., Hillman Power Company, L.L.C., Tondu Corporation, Viking Energy of Lincoln, LLC, and Viking Energy of McBain, LLC, (collectively, the Biomass Merchant Plants (BMPs)); the Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan; Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance (jointly, EIBC/IEI/CGA); Midland Cogeneration Venture Limited Partnership (MCV); Michigan Electric Transmission Company, LLC (METC); Wolverine Power Supply Cooperative, Inc. (WPSC); Michigan Public Power Agency (MPPA); Residential Customer Group (RCG); Citizens Utility Board of Michigan (CUB); and Urban Core Collective (UCC). Permissive intervention was granted to the Mackinac Center for Public Policy (Mackinac). Consumers and the Commission Staff (Staff) also participated in the proceeding.

The ALJ issued a Proposal for Decision (PFD) on March 7, 2022. On or before March 21, 2022, exceptions were filed by Consumers, HSC, the Attorney General, the Staff, MNS, the CEOs, GLREA, Mackinac, ABATE, the BMPs, UCC, EIBC/IEI/CGA, and WPSC. On March 28, 2022, replies to exceptions were filed by Consumers, Energy Michigan, HSC, the Attorney General, the Staff, MNS, the CEOs, GLREA, ABATE, the BMPs, UCC, EIBC/IEI/CGA, and WPSC.

On April 20, 2022, Consumers entered into a settlement agreement with the following parties: the Staff, MNS, the Attorney General, the CEOs, UCC, CUB, HSC, EIBC/IEI/CGA, METC, and

GLREA. The settlement agreement recommends approval of Consumers' proposed course of action (PCA) with changes and covers issues such as: the acquisition of new resources; investments in demand response (DR), conservation voltage reduction (CVR), and energy waste reduction (EWR); deployment of energy storage; retirement of certain coal-fired generation units and associated decommissioning costs; a financial compensation mechanism (FCM); avoided cost methodology under the Public Utility Regulatory Policies Act of 1978 (PURPA); and implementation of competitive bidding. MPPA, MCV, RCG, and ABATE did not join the settlement, but offered statements of non-objection.

On April 20, 2022, Consumers and the Staff jointly filed a motion to extend the statutory deadline found in Section 6t(7) of Act 341, MCL 460.6t(7). In its April 25, 2022 order in the present case (April 25 order), the Commission granted the joint motion and extended the deadlines for the Commission's 300-day and 360-day orders. In addition, the Commission set a tentative schedule for the remainder of this proceeding. *See*, April 25 order, p. 5.

On May 4, 2022, Energy Michigan, Mackinac, WPSC, and the BMPs filed responses objecting to the settlement agreement. MNS, the CEOs, Energy Michigan, the Staff, the BMPs, and WPSC filed direct testimony in the contested settlement phase of this proceeding on May 9, 2022. MNS, the Staff, EIBC/IEI/CGA, WPSC, the BMPs, Consumers, and the CEOs filed rebuttal testimony on May 13, 2022. Initial briefs on the contested settlement were filed by MNS, Mackinac, EIBC/IEI/CGA, the Attorney General, the CEOs, HSC, the Staff, Consumers, CUB, the BMPs, and WPSC on May 25, 2022, and reply briefs were filed by MNS, the Staff, the CEOs, Consumers, WPSC, and the BMPs on May 27, 2022. UCC filed a letter in support of the settlement agreement on May 25, 2022. The evidentiary record in this contested settlement proceeding consists of 315 pages of transcript and 22 exhibits, all of which appear in Volume 10 of the transcript. Unless otherwise noted, all citations to briefing in this order refer to the briefing in the contested settlement phase of this case and not the contested IRP phase.

II. Applicable Law

Act 341 requires the Commission to approve an IRP if the proposed IRP "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs" based on whether the proposed plan: (1) appropriately balances a series of statutorily listed factors; (2) uses a workforce comprised of residents of this state to the extent practicable in the completion of construction or investment in new or existing capacity resources; and (3) meets the requirements of subsection 6t(5) of Act 341, which enumerates the information to be included in an IRP. MCL 460.6t(8).

In addition, Rule 431 of the Michigan Administrative Code, Mich Admin Code, R 792.10431, governs proceedings before the Commission where a settlement is filed. Pursuant to Rule 431(5)(a)-(c), the Commission may approve a contested settlement agreement when the Commission determines the following conditions are met: (1) objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, and (3) the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, and is supported by substantial evidence on the record as a whole.

III. Proposed Settlement Agreement

Under the terms of the settlement agreement, the parties to the settlement (settlement parties) agree that Consumers' PCA, as modified, should be approved by the Commission as the most reasonable and prudent means of meeting the company's energy and capacity needs for the 5-year, 10-year, and 15-year time horizons as required by Sections 6t(3) and 6t(8)(a) of Act 341, MCL 460.6t. Settlement Agreement, p. 3. The settlement parties agree that Consumers will file its next IRP consistent with the requirements of Section 6t. *Id*. The settlement agreement, attached to this order as Exhibit A, contains the following provisions relevant to the arguments in the contested settlement proceeding:

The settlement agreement provides that Consumers' PCA shall include the proposed purchase of the New Covert Generating Facility (Covert plant) in 2023 but shall not include the ownership of the Dearborn Industrial Generation Plant (DIG), the Livingston Generating Station (Livingston), and the Kalamazoo River Generating Station (Kalamazoo) (collectively, CMS plants). Settlement Agreement, pp. 2-3. The parties agree that the identified capital costs that Consumers will incur for DR, CVR, and the purchase of the Covert plant in the next three years are reasonable and prudent, should be approved for cost recovery purposes, and will be included in Consumers next electric rate case, consistent with Sections (11) and (17) of Act 341, MCL 460.6t(11),(17). *Id*., p. 4. The parties agree to the projected capacity values provided by the Covert plant, and DR, CVR, and EWR resources in the next three years. *Id*.

The settlement provides for the approval of a battery deployment program as proposed in rebuttal testimony of company witness Blumenstock in the principal case. *Id*.; *see also*, 3 Tr 185, 203-205.

The settlement agreement provides that D.E. Karn (Karn) Units 3 and 4 will be retired on or before May 31, 2031, and J.H. Campbell (Campbell) Units 1, 2, and 3 will be retired on or before May 31, 2025. Settlement Agreement, pp. 4-5.

The settlement agreement provides that Consumers shall issue a one-time competitive solicitation following the approval of the settlement agreement that includes the following parameters:

> a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO [Midcontinent Independent System Operator, Inc.] Zone 7 starting in the 2025 Planning Year;
>
> b. The One-Time Solicitation will include two all source tranches:
>
> > i. The first tranche will seek up to 500 ZRCs [zonal resource credits] of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs [power purchase agreements] with terms up to 10 years. This tranche will seek dispatchable, nonintermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
> >
> > ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the OneTime Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs [requests for proposals] and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
>
> c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the OneTime Solicitation;
>
> > i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated 7 with the project(s) that

> prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.
>
> d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

Id., pp. 6-7.

The settlement agreement provides for an extension of the annual competitive bidding process used to acquire supply-side resource technologies as approved in the settlement agreement in Case No. U-20165 with modifications. *Id*., pp. 7-9.

The settlement agreement provides that Consumers "will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers." *Id*., p. 11. The settlement agreement also provides that Consumers will donate $2 million annually to the same fund during the amortization period for the regulatory asset created to recover the unrecovered book balance of Campbell Units 1, 2, and 3. *Id*. These donations will not be recovered in rates. *Id*., p. 12.

The settlement agreement provides that in future IRPs, Consumers will: "(i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential." *Id*.

The settlement agreement provides that Consumers will "develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources . . . ." *Id*. The settlement also provides that in its next IRP, Consumers will "consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system." *Id*., p. 13.

The settlement agreement provides that Consumers' next IRP will include further analyses on environmental emissions, health impacts from emissions, and environmental justice. The settlement agreement also provides that Consumers will "take . . . steps to engage and gather input from the public prior to the filing of its next IRP with the Commission . . . ." *Id.*, pp. 13-14.

IV. Evidentiary Record

Because the Commission has decided to read the record for purposes of evaluating the settlement agreement, a summary of the evidentiary record related to the settlement agreement follows.[1]

A. Direct Testimony

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

MNS and CUB presented the direct testimony of Douglas B. Jester. Mr. Jester testifies that the settlement agreement is in the public interest and recommends that the Commission approve the settlement agreement. Mr. Jester opines that "retiring the entire Campbell plant will benefit both customers and the environment and is therefore in the public interest." 10 Tr 4327. Mr. Jester notes that no party in this case opposed the retirement of Campbell Units 1 and 2 and adds that the ALJ also recommended approval of these retirements. Mr. Jester posits that "[t]he Campbell plant has a greater carbon impact than any other resource owned by [Consumers], and its retirement is critical to meeting state and federal climate goals, including the Michigan Healthy Climate Plan." 10 Tr 4327 (footnote omitted). Mr. Jester presents tables compiling Michigan's greenhouse gas emissions and the associated goals from the MI Healthy Climate Plan to

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[1] The Commission notes that, in the original IRP proceeding that resulted in a PFD, the evidentiary record included 4,094 pages of transcript across nine volumes and over 500 exhibits with certain transcript pages and exhibits designated as confidential. PFD, p. 3. The Commission references this evidence throughout this order.

demonstrate that it is “not possible to meet the 2025 goal of the Michigan Healthy Climate Plan without the retirement of the Campbell plant by 2025[,]” adding that, “the Michigan Healthy Climate Plan calls for the retirement of all coal generation by 2030, which would necessarily include the Campbell units.” 10 Tr 4330.

Mr. Jester adds that because the Campbell plant emits other pollutants, such as sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter ($PM_{2.5}$), the retirement of the entire Campbell plant is likely to have health benefits beyond those of reducing the company’s carbon output. 10 Tr 4327.

In addition to the environmental and health benefits outlined above, Mr. Jester testifies that “[e]xtensive modeling conducted by Consumers and by MNS in this case demonstrated that retiring Campbell in 2025 is economic for customers.” 10 Tr 4327.

Mr. Jester provides that “paragraph 1 of the [settlement] agreement approves Consumers’ continued ramp-up of solar resources—an initiative first approved as part of Consumers’ 2018 IRP.” 10 Tr 4330. Additionally, Mr. Jester provides that:

> In the 2018 case, the Commission approved a plan that included approximately 5 GW [gigawatts] nameplate [capacity] of new solar resources in the 2020s. In this case, Consumers proposed to continue those additions and also procure an additional 2 GW of solar in the 2030s above the levels included in the 2018 IRP. Paragraph 8 of the settlement agreement provides that Consumers will continue to utilize annual competitive solicitations to procure these solar resources.

10 Tr 4330. Mr. Jester posits that the Consumers’ proposed procurement is a reasonable and beneficial settlement term. 10 Tr 4330. Mr. Jester notes that the benefits the Commission recognized in 2018 IRP, such as the environmental benefits of additional renewable energy resources and the use of annual solicitations to promote competitive pricing, will continue with the new settlement agreement. 10 Tr 4331.

With respect to the proposed gas plant acquisitions, Mr. Jester opines that the settlement agreement terms regarding the acquisition of the Covert gas plant are reasonable and prudent. 10 Tr 4331. Mr. Jester provides that these terms include the approval of the acquisition of Covert and the recovery of the associated $815 million purchase cost. The parties also agreed that Consumers would not obtain the CMS plants from its affiliate, CMS Enterprises Company (CMS Enterprises). 10 Tr 4331.

Mr. Jester notes that no party opposed the acquisition of the Covert plant and the ALJ recommended the Commission approve the acquisition. 10 Tr 4331. Mr. Jester posits that both the Staff and Consumers testified in the primary proceeding that "because Covert is currently in PJM [PJM Interconnection, L.L.C.'s American Electric Power (AEP) Zone], Consumers' acquisition of Covert will add 1,114 Zonal Resource Credits or ZRCs to MISO Zone 7." 10 Tr 4331. Mr. Jester adds that the addition of these ZRCs to Zone 7 "will support reliability for Consumers as well as overall resource adequacy for Zone 7." 10 Tr 4331. Mr. Jester concludes that "[f]or these reasons, acquisition of Covert is both in the public interest from a reliability and resource adequacy standpoint" and is supported by the record in this case. 10 Tr 4331.

Mr. Jester asserts that Consumers' agreement not to acquire the CMS plants is also in the public interest. Mr. Jester posits that the record demonstrated numerous concerns with acquisition of these plants from CMS Enterprises including, "issues with respect to affiliate transactions" and "the nature of the gas plant RFP solicitation that led to the proposed purchase of these plants . . . ." 10 Tr 4331-4332. Finally, Mr. Jester notes that the ALJ and the Staff also recommended the Commission deny the acquisition of the affiliate plants from CMS Enterprises. 10 Tr 4332.

Mr. Jester supports the proposed one-time solicitation of capacity and energy for the 2025 planning year (PY). Mr. Jester outlines the terms of the one-time solicitation as follows:

> In paragraph 6 of the settlement [agreement], the parties agree that Consumers will issue a one-time competitive solicitation for PPAs to begin in PY 2025. The solicitation will contain two tranches. The first tranche will seek up to 500 ZRCs of energy and capacity for up to 10 years from dispatchable, non-intermittent generation. The second tranche will seek up to 200 ZRCs of energy and capacity for up to 25 years from clean energy resources (including battery storage).

10 Tr 4333. Mr. Jester posits that "[t]he first tranche will provide energy and capacity of similar characteristics to what Consumers sought via the proposal to acquire the CMS plants[,]" adding that "soliciting 10-year PPAs instead of acquiring affiliate assets planned to remain in rate base until 2040 will reduce risks to customers." 10 Tr 4333. Mr. Jester also notes that a solicitation for PPAs addresses some of the issues identified with the earlier RFP by parties and the ALJ's decision, which include that the earlier RFP only sought assets for purchase, and risks related to environmental permitting and fixed operating and maintenance expenses. 10 Tr 4333. Mr. Jester testifies that the second tranche is also in the public interest as it will "provide additional clean energy resources for Consumers' portfolio . . . ." 10 Tr 4334.

Mr. Jester provides that "[p]aragraph 4(i) of the settlement [agreement] provides that Karn units 3-4 will not retire in 2023 but instead will continue operating and retire on or before their previously planned retirement date of May 31, 2031, absent extraordinary circumstances." 10 Tr 4334. Mr. Jester posits that Karn Units 3 and 4 "provide substantial capacity but operate infrequently." 10 Tr 4334. Mr. Jester testifies that "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements [PRMR] by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. Further, Mr. Jester notes that Karn Units 3 and 4 staying online supports resource adequacy in MISO Zone 7 by maintaining these additional ZRCs. Mr. Jester testifies that keeping Karn Units 3 and 4 in operation removes the "unrecovered net book value from the total balance of the regulatory asset that Consumers seeks . . . lowering the costs of the regulatory asset for customers." 10 Tr 4334-4335.

Mr. Jester supports the regulatory asset provisions of the settlement agreement mentioned above. Mr. Jester provides that “[i]n paragraph 5 of the settlement, the parties agree that after retirement of the Campbell plan in 2025, the return on equity used to calculate the WACC [weighted average cost of capital] for the regulatory asset will be 9.0%.” 10 Tr 4335. Mr. Jester posits that:

> Consumers has taken a very firm position that it will not retire Campbell in 2025 without being able to recover a return of and on the unrecovered balance. Therefore, it was necessary for the other parties to agree with a regulatory asset based on WACC for this settlement [agreement] to occur and to facilitate Consumers’ permanent exit from coal generation three years from now.

10 Tr 4335. Mr. Jester notes, however, that “setting the ROE [return on equity] at 9.0% for the calculation of the WACC on the regulatory asset is a significant compromise for Consumers, as that figure is substantially lower than the authorized ROE of 9.9% that the Commission approved in Consumers Energy’s last electric rate case, [Case No.] U-20963.” 10 Tr 4335.

Mr. Jester posits that Consumers’ low-income customer bill assistance donations are a beneficial settlement term. Mr. Jester provides that “Consumers agreed in paragraph 13 of the settlement [agreement] to donate funds to its low-income bill assistance programs.” 10 Tr 4336. Mr. Jester notes that these funds will not be recovered in rates. Specifically, “Consumers will donate $5 million in 2022 and $2 million per year for the rest of the term of the regulatory asset for the Campbell plant.” 10 Tr 4336. Mr. Jester asserts that “[t]he need for additional low-income customer bill assistance has been demonstrated both in recent Consumers electric rate cases and in recent Consumers EWR cases, and recognized by the Commission in a variety of orders.” 10 Tr 4336 (footnote omitted).

Mr. Jester provides that “[p]aragraph 9 of the settlement [agreement] requires Consumers to use commercially reasonable efforts to maintain the 50/50 split between owned resources and

PPAs for new solar procurements" that was first approved in the settlement agreement in Case No. U-20165. 10 Tr 4336. Mr. Jester also notes that paragraph 9 "creates an absolute cap of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while setting no cap on the amount of new solar the Company may acquire via PPA" and "maintains the bar on Consumers affiliates participating in the PPA portion of the solicitations." 10 Tr 4337. Mr. Jester opines that "[t]he Commission found this allocation reasonable and in the public interest" in Consumers last IRP and that "this term maintains the essential components of that agreement." 10 Tr 4337. Mr. Jester posits that making a commercially reasonable efforts to maintain the 50/50 split "promotes competition among third-party developers which reduces customer costs" and "helps support the solar industry in Michigan." 10 Tr 4337. Mr. Jester notes that this provision of the settlement agreement is consistent with the ALJ's recommendations on the issue. 10 Tr 4337.

Mr. Jester testifies that paragraph 10 of the settlement agreement provides for an extension of the FCM approved in Case No. U-21065, Consumers' 2018 IRP. 10 Tr 4337. Mr. Jester opines that "[a]n FCM is a reasonable incentive for the Commission to authorize" given that "Consumers has substantially changed its business model by agreeing to shift its resource portfolio away from coal generation and toward solar generation, and by agreeing to procure the solar generation via competitive solicitations under which half of that capacity will be in the form of PPAs." 10 Tr 4338.

Mr. Jester provides that paragraph 16 of the settlement agreement "states that the parties agree in Consumers' next IRP to consider how transmission investments can improve reliability and access to economic sources of power from areas outside Zone 7." 10 Tr 4338. Mr. Jester supports the transmission provision as a reasonable and beneficial settlement term and notes that the ALJ's decision "found that Consumers' transmission analysis in this case was deficient and did not meet the terms of the settlement agreement in [Case No.] U-21065." 10 Tr 4338-4339.

Mr. Jester supports the proposed battery storage investments outlined in the settlement agreement. Mr. Jester provides that the "parties agree to approval of a battery deployment program in paragraph 3 of the settlement agreement" as proposed in the principal rebuttal testimony in this case. 10 Tr 4339. Mr. Jester outlines that "Consumers proposed . . . to advance investment in 75 MW [megawatts] of battery storage resources. The settlement [agreement] reserves approval of the costs of the program to future electric rate cases." 10 Tr 4339. Mr. Jester posits that Consumers made the battery proposal in response to testimony from the Staff, MNS, and other parties that "called for acceleration of battery storage investments as part of Consumers' resource portfolio for this IRP." 10 Tr 4339. Mr. Jester notes that "battery deployment will provide another clean energy resource to bolster Consumers' maintenance of its PRMR and support resource adequacy in Zone 7." 10 Tr 4339.

Mr. Jester provides that in paragraph 14 of the settlement agreement, Consumers agrees "to collect further data on marginal line losses and to include marginal line losses and avoided transmission and distribution (T&D) costs in the evaluation of all distributed resources, including residential demand response, for its next IRP." 10 Tr 4340. Mr. Jester defers to testimony of CUB witness David Gard and MNS witness Chris Neme in explaining "the importance of these issues to the evaluation of EWR potential and DR potential for future IRPs." 10 Tr 4340.

Mr. Jester notes that paragraphs 17 and 18 of the settlement agreement contain provisions regarding an environmental justice analysis and community outreach for Consumers' next IRP. Mr. Jester supports these settlement terms and posits that "[t]he environmental justice analysis will provide vital information regarding the people and communities who bear disproportionate impacts of electric generation activities—information that has been lacking in Michigan IRP cases up until now." 10 Tr 4341.

Finally, Mr. Jester provides that "[p]aragraph 7 of the settlement agreement requires Consumers to publicly file its community transition plans for the Campbell and Karn sites." 10 Tr 4341. Mr. Jester defers to testimony of MNS witness Tyler Comings regarding the need for public filing of transition plans. 10 Tr 4341.

Mr. Jester concludes that "[t]he settlement agreement in this case continues and significantly extends the progress of the settlement [agreement] in [Case No.] U-20165." 10 Tr 4341. Mr. Jester posits that the settlement agreement is "supported by the great weight of evidence in the record of this case and consistent with many of the findings and recommendations in the PFD." 10 Tr 4342. Thus, Mr. Jester recommends the Commission approve the proposed settlement agreement.

2. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

The CEOs presented the direct testimony of James Gignac, Senior Midwest Energy Analyst employed by the Union of Concerned Scientists. Mr. Gignac posits that the proposed settlement supports the public interest. Mr. Gignac posits that the settlement agreement "supports the public interest in three main ways: (1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company's next IRP." 10 Tr 4375.

Mr. Gignac avers that "Consumers approach of retiring all its coal-fired power plants by 2025 aligns with Governor Whitmer's MI Healthy Climate Plan's goal to phase out Michigan's remaining coal plants by 2030" and "the Company's plans to add 8,000 megawatts of solar by

2040 is an important step toward the MI Healthy Climate Plan's target for renewable energy to be providing 60 percent of Michigan's electricity generation by 2030." 10 Tr 4375.

Mr. Gignac posits that "the proposed settlement [agreement] helps reduce financial and public health costs related to Consumers' resource plan" because "the Company has agreed to a lower rate of return for its retiring coal plants and will commit tens of millions of dollars of shareholder funds to support bill assistance for lower-income customers." 10 Tr 4376. Mr. Gignac opines that expert testimony in this case "demonstrated the benefits of earlier coal plant retirements in the form of avoided negative health outcomes." 10 Tr 4376.

Finally, Mr. Gignac argues that commitments made by Consumers for its future IRPs "will ensure that additional information and perspectives are available to inform both the Company's assessment of its future resource options as well as Commission and stakeholder review of its proposals." 10 Tr 4376-4377. Mr. Gignac includes the agreement to model distributed generation as a resource, to conduct public health and environmental justice analyses, and to expand opportunities and forums for community input among the beneficial modeling and community engagement commitments made by Consumers. 10 Tr 4376-4377.

For the reasons outlined above, Mr. Gignac concludes that the Commission should approve the settlement agreement as it "represents a reasonable resolution of the issues . . . ." 10 Tr 4377.

3. Energy Michigan

Energy Michigan presented the direct testimony of Alexander J. Zakem. Mr. Zakem testifies that in the contested settlement agreement, Consumers fails to address the impacts the PCA will have on resource adequacy and the competitive market. Mr. Zakem explains that the settlement agreement does not require that the 500 ZRC capacity need that Consumers is seeking to fill through the one-time solicitation agreed to under subsection 6.b.i of the settlement agreement "be additional to what is already being counted toward MISO Zone 7's resource adequacy requirements." 10 Tr 4297. Mr. Zakem opines that because the settlement agreement does not require that the capacity being added by Consumers be additional to that already available in Zone 7, the settlement agreement is subject to concerns about "insufficient resources in the zone for a competitive pricing market." 10 Tr 4298. Mr. Zakem therefore recommends the Commission "examine the [s]ettlement [agreement] carefully and review its effects on resource adequacy and competitive pricing in Zone 7" and if the Commission finds that the settlement agreement "fails to adequately address resource adequacy or anti-competitive concerns, then the Commission should reject the [s]ettlement [agreement]." 10 Tr 4298.

4. The Commission Staff

In the Staff's direct testimony, Paul Proudfoot, the Director of the Energy Resources Division, asserts that Consumers' PCA, as modified by the settlement agreement, meets the statutory requirements of Section 6t(8) of Act 341, MCL 460.6t(8). 10 Tr 4400. For this reason, Mr. Proudfoot recommends the Commission approve the contested settlement agreement in its entirety without recommending changes under Section 6t(7). 10 Tr 4400. Mr. Proudfoot also states that the contested settlement agreement meets the requirements of Rule 431. 10 Tr 4400.

5. Biomass Merchant Plants

The BMPs presented the direct testimony of Richard A. Polich, a Managing Director with GDS Associates, Inc. Mr. Polich testifies that the continued operation of the biomass plants can offset some deficiencies he posits are present in the proposed contested settlement agreement.

Mr. Polich opines that the settlement inconsistently results in Consumers having excess generation capacity in some years and capacity shortages in other years, which he argues is contrary to IRP best practices. Mr. Polich explains:

> The settlement [agreement] includes procurement of the Covert Generation Facility (Covert) in 2023 which results in Consumers' having 20.1% excess capacity. It then adds 700 MW (ZRC) of generation resources in 2025 that is procured through a competitive solicitation that is deeply flawed. Although Consumers retires 1,344 MW (ZRC) of generation in 2025, the [s]ettlement [agreement] would result in 16.2% excess generation in 2025 and an average of 18.7% excess generation over the next six years, assuming solar generation continues to be accredited at 50% of real capacity by MISO.

10 Tr 4277. Further, Mr. Polich adds that "[t]he addition of Covert in 2023 means Consumers' rate payers will be paying 2 years of unnecessary costs for Covert capacity that is unnecessary." 10 Tr 4277. Mr. Polich likens the biomass plants to solar generation as they are net zero carbon generation and to natural gas plants as they are baseload generation. Mr. Polich concludes that:

> If it is reasonable and prudent for Consumers to acquire both fossil and renewable capacity from 2023 through 2030 that results in excess capacity for the period of 2023-2030, the prudent course of action is for Consumers to continue to purchase capacity and energy from the Biomass Plants after the expiration of their current contracts through at least 2035 when Consumers is likely to be capacity deficient.

10 Tr 4278.

Mr. Polich argues that the one-time solicitation outlined in section 6 of the settlement agreement is "deeply flawed." 10 Tr 4278. Mr. Polich posits that the timing of the competitive solicitation is flawed as "Consumers is proposing to start the procurement process so the capacity of both tranches will provide capacity in 2025." 10 Tr 4278. Mr. Polich opines that:

> The timing of the procurement process will not result in new capacity being added to the Michigan market and will likely favor existing generation facilities such as the Kalamazoo Plant, Livingston Plant and Dearborn Industrial Generation because it will be impossible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing and construct the plant by 2025.

10 Tr 4279. Mr. Polich concludes that, given the timeline to obtain a MISO interconnection agreement, complete project engineering, and obtain financing, "it is very unlikely that there will be sufficient time to complete a power generation project for operation in 2025." 10 Tr 4279.

Mr. Polich also argues that "MISO Zone 7 is projected to be short 397.4 MW (ZRC) in 2023." 10 Tr 4279. Mr. Polich notes that "MISO's recent [sic] completed 2022/2023 Planning Resource Auction (PRA) resulted in capacity shortages in all northern MISO regions due to planned retirements of fossil generation resources . . . . The PRA resulted in capacity costs of $236.66/MW-day in MISO Zone 7, which is equal to the cost of new entry [CONE] or cost of adding new gas fired generation." 10 Tr 4279. Mr. Polich posits that this "shows the volatility of the MISO planning process to which Consumers and its customers will be subject." 10 Tr 4279.

Mr. Polich posits that the one-time solicitation outlined in the settlement agreement "results in a preference for non-intermittent fossil generation . . ." 10 Tr 4280. As outlined in the settlement agreement, the one-time solicitation seeks projects that will provide the company with capacity in MISO Zone 7 starting in the 2025 planning year. The settlement agreement also states that the first tranche will seek "dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7." Settlement Agreement, p. 6. Mr. Polich argues that these requirements preclude the participation of the BMPs as they will still be under contract in 2025 and can be dispatched on 24 hours-notice, as opposed to hourly. 10 Tr 4280. Mr. Polich further asserts that "only generation resources which are currently operating, not under contract with Consumers, have obtained MISO interconnection approval, and completed primary engineering are likely to be able to bid into the One-Time Solicitation." 10 Tr 4280.

Mr. Polich takes issue with the language in the settlement agreement describing the second tranche of the one-time solicitation that states, "[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources." 10 Tr 4280 (quoting Settlement

Agreement, p. 6). Mr. Polich posits that "[t]he term 'clean capacity resources' is an undefined term and can mean any generation resource that is cleaner that [sic] Consumers existing generation resources. Thus, natural gas plants could offer proposals into the second tranche because the language is very ambiguous." 10 Tr 4280.

Mr. Polich opines that "the One-Time Solicitation will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity." 10 Tr 4281. Mr. Polich argues that an increase in the average price of natural gas over the last two years "clearly demonstrates the volatility of natural gas pricing and highlights the risk of becoming totally dependent on such a single, volatile fuel source." 10 Tr 4281.

Mr. Polich also posits that the one-time solicitation in the second tranche of the settlement agreement "will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials[,]" specifically lithium carbonate. 10 Tr 4281.

Mr. Polich opines that if MISO changes the solar ZRC accreditation from its current 50% accreditation to a 30% accreditation, Consumers will face a capacity shortfall in 2031 due to closing of Karn Units 3 and 4 and the expiration of Consumers contract with Midland Cogeneration Venture. 10 Tr 4282.

Mr. Polich avers that the settlement agreement does not meet the stated goals of paragraph 16 "to be Carbon Neutral by 2040[,]" as the Covert plant and 200 MW of generation from PPAs originating under the one-time solicitation "are fossil fuel generation resources and are not carbon neutral." 10 Tr 4283.

In conclusion, Mr. Polich requests, on behalf of the BMPs that "the Commission approve the Settlement Agreement only if it is amended to include a provision whereby Consumers Energy continues to purchase capacity and energy from the Biomass Plants" through amended PPAs. 10 Tr 4286.

6. Wolverine Power Supply Cooperative

WPSC presented the direct testimony of Thomas King, Jr. Mr. King argues that "Consumers Energy's and Michigan's reliability and resource adequacy situation is no better (and arguably, worse) under the proposed Settlement Agreement than in the originally filed IRP." 10 Tr 4301. Mr. King posits that "the changes reflected in the proposed Settlement Agreement continue to assume capacity replacements that add no incremental capacity to MISO Zone 7." 10 Tr 4302. Mr. King provides MISO's 2022 PRA results as exhibit WPSC-6. Mr. King argues that this exhibit demonstrates why MISO's North and Central Zones cleared at CONE in 2022. Mr. King quotes MISO as stating "that previous projections of surplus were 'eroded by an increased load forecast, less capacity entering the auction as result of retirements, and the decreased accredited capacity of new resources.'" 10 Tr 4303 (quoting Exhibit WPSC-6, slide 2)(emphasis omitted). Mr. King posits that "[w]hen load growth is under-forecasted, dispatchable resources are retired too quickly, and intermittent resources are over-accredited, reliability is at risk." 10 Tr 4303. Mr. King further quotes the MISO 2022 PRA results as stating that "[u]nless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue." 10 Tr 4303 (quoting Exhibit WPSC-6, slide 9).

Mr. King further avers that under the settlement agreement, Consumers' plan is "based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources that likely cannot be built in time and, therefore, is likely to result in the purchase from the affiliated plants because they will be the only dispatchable resources in Zone 7 . . . .” 10 Tr 4302-4303.

Finally, Mr. King argues that “when Consumers’ PCA and proposed Settlement Agreement assumptions are updated to reflect more current data from Consumers’ own capacity demonstration filing in Case No. U-21099 and more reasonable assumptions, Consumers will likely be capacity negative in 2025[,]” meaning it will be “unlikely to serve its own load with its own resources in 2025.” 10 Tr 4303-4304. Mr. King posits that the assumptions Consumers used in its capacity demonstration are unreasonable. Specifically, Mr. King states that it is unreasonable for Consumers to assume a declining PRMR in its PCA and capacity demonstration as “it conflicts with MISO’s statements of increasing load forecasts (see Exhibit WPSC-6), Wolverine’s own growth, and publicly disclosed growth in Michigan.” 10 Tr 4305. Similar to the BMPs, Mr. King avers that “MISO is considering changes to solar capacity accreditation to move from a static solar accreditation value to an Effective Load Carrying Capability (ELCC) approach, similar to what is used for wind.” 10 Tr 4306-4307. Mr. King also outlines similar concerns regarding supply chain challenges causing disruptions to solar project developments. Specifically, Mr. King opines that “disruptions in the solar industry due to the United States Department of Commerce [DOC] investigation into Chinese solar tariff avoidance, are likely to result in project development delays.” 10 Tr 4307.

Mr. King concludes that the Commission “should reject this settlement [agreement]” and “adjust the timeline for retirement of Campbell 3 in a way that reasonably ensures replacement is possible—not only for the joint owners of Campbell 3, but for all LSEs [load serving entities] who rely on the grid to ensure their own reliability . . . .” 10 Tr 4309.

B. Rebuttal Testimony

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

Mr. Jester, on behalf of MNS and CUB, responds to the direct settlement testimony of WPSC, Energy Michigan, and the BMPs. Mr. Jester focused his rebuttal testimony on "the objecting parties' claims regarding resource adequacy, the procurement of new clean energy resources by 2025, and MISO capacity credit for solar resources." 10 Tr 4346.

Mr. Jester responds to claims by WPSC and Energy Michigan that the settlement agreement would worsen the resource adequacy measures in Zone 7 by arguing that "[u]nder the settlement, more than 2,000 ZRCs of capacity will be added to Zone 7 over the next several years." 10 Tr 4349. Mr. Jester posits that "[t]hese resource additions will not only provide replacement capacity for the retiring Campbell coal plant in 2025, they will result in a significant net increase of capacity when compared to the status quo." 10 Tr 4349. Specifically, Mr. Jester provides that "the settlement [agreement] will add 1,114 ZRCs to MISO Zone 7 through the acquisition of the Covert combined-cycle gas plant in 2023." 10 Tr 4349 (footnote omitted). Mr. Jester adds that "the settlement [agreement] provides that Consumers will deploy a new, utility-scale battery storage program in the years 2024-27, which will add approximately 71 ZRCs of new capacity." 10 Tr 4349-4350 (footnote omitted). Mr. Jester posits that "because the settlement agreement preserves the solar ramp-up proposed as part of the original PCA, the settlement [agreement] would add 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029 with further increases throughout the 2030s." 10 Tr 4350 (footnote omitted). Finally, Mr. Jester argues that "by preserving the EWR and DR provisions from Consumers' original PCA, the settlement [agreement] will provide 94 ZRCs of demand-side resources by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years."

10 Tr 4350 (footnote omitted). Mr. Jester concludes that these resource additions will support resource adequacy by providing replacement capacity for the retiring Campbell Units in May 2025. Specifically, Mr. Jester avers that "[i]n the 2025/2026 planning year . . . the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected increase will be at least 923 ZRCs." 10 Tr 4350. Mr. Jester notes that these calculations are conservative as they only account for the first tranche of the one-time solicitation seeking up 500 ZRCs of energy and capacity for up to 10 years from dispatchable generation and do not include the resources from the second tranche seeking up to 200 ZRCs of energy and capacity for up to 25 years from clean capacity resources. Mr. Jester posits that the calculations also assume that all of the dispatchable ZRCs come from existing generation sources. Mr. Jester concludes that "the settlement [agreement] will bolster Zone 7's resource adequacy" and as such, the Commission should disregard resource adequacy concerns raised by WPSC and Energy Michigan. 10 Tr 4352.

Mr. Jester responds to claims by WPSC and posits that "the settlement agreement will improve Consumers' capacity position relative to the original IRP." 10 Tr 4352. Mr. Jester opines that WPSC's claim that the proposed settlement agreement continues to assume capacity replacements that add no incremental capacity to Zone 7 is "plainly incorrect" as "the settlement provides for more than 2,000 ZRCs of new Zone 7 capacity over the next six years, including the addition of the Covert plant (1,114 ZRC) in 2023. 10 Tr 4353. Mr. Jester posits that, as explained above, the one-time solicitation will result in a net increase of ZRCs in both the 2025/26 and 2028/29 planning years. 10 Tr 4353.

Mr. Jester responds to WPSC's arguments that solicited resources cannot be built in time to provide energy and capacity in the 2025/26 planning year. Mr. Jester posits that "no party has claimed that the dispatchable generation tranche will be supplied with new resources" and thus, "the evidence does not support Mr. King's speculative claims about the difficulty of developing new clean energy resources by 2025/26." 10 Tr 4353. Further, Mr. Jester avers that "Consumers would have enough capacity resources to meet customer needs in 2025/26 even if the one-time solicitation failed entirely." 10 Tr 4353.

Finally, regarding Consumers' capacity position, Mr. Jester rebuts WPSC's claim that Consumers will be capacity negative in 2025. Mr. Jester posits that the testimony provided by Mr. King "does not explain some of the assumptions reflected in [Exhibit WPSC-7]" and "does not present independent sources to support his claims about increased load and the PRMR margin." 10 Tr 4355 (footnote omitted). Mr. Jester also avers that Mr. King's projected capacity position assumes that Karn Units 3 and 4 were operating in planning year 2025/2026 when Consumers capacity demonstration filing assumed Karn Units 3 and 4 would have retired in 2023, and the CMS plants would be acquired in 2025, in line with the implementation of the original PCA. Mr. Jester notes that in Case No. U-21099, the Staff concluded that "all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2025/26." 10 Tr 4356 (quoting Case No. U-21099, filing #U-21099-0060, p. iii).

Mr. Jester addresses the arguments of the BMPs and WPSC about recent PRA results. As Mr. Jester summarizes, "Mr. Polich asserts that MISO Zone 7 is projected to be short in 2023, and Mr. King cites the PRA results in warning more broadly about reliability risks." 10 Tr 4358 (footnote omitted). Mr. Jester opines that "[a]lthough . . . MISO should carefully scrutinize the PRA results and pursue solutions to improve resource adequacy for MISO North/Central, the auction results do not undercut the settlement agreement in this case." 10 Tr 4358. Mr. Jester reiterates that "the settlement agreement will *improve* Zone 7's resource adequacy." 10 Tr 4358-

4359 (emphasis in original). Further, Mr. Jester posits that “[b]ecause the settlement improves the capacity position of MISO Zone 7, it therefore also improves the capacity position of MISO’s North/Central region.” 10 Tr 4360.

Mr. Jester responds to the BMPs’ and WPSC’s concerns that there is not enough time to develop new resources capable of bidding into the one-time solicitation for clean energy resources and the possible decline of the ELCC of solar. Mr. Jester posits that concerns about developing clean energy resources by the 2025/2026 planning year are based on the assumption that the development process would not start until 2023. 10 Tr 4361. Mr. Jester first reiterates his position that “no one has suggested that the dispatchable generation tranche (500 ZRCs) of the one-time solicitation will be filled with new resources. . . .” 10 Tr 4362. Mr. Jester then opines that while the witnesses for the BMPs and WPSC assume that projects will not begin development until 2023, “[i]n reality, there are numerous clean energy projects already in the MISO generator interconnection queue. Because these projects are already in development, many of them will likely be capable of bidding into the solicitations for planning year 2025/26.” 10 Tr 4362-4363. Mr. Jester posits that there are currently “more than 13,011 MW of solar, battery, and solar/battery hybrid projects located in the MISO Zone 7 that have an application in-service date by or before June 1, 2025” including “9,842 MW of solar, 1,249 MW of solar/battery hybrid, and 1,920 MW of battery storage.” 10 Tr 4363-4364 (footnotes omitted). Mr. Jester notes that a number of the projects have completed phase 2 or phase 3 of interconnection studies and are therefore highly likely to proceed. 10 Tr 4364. Mr. Jester thus concludes that the concerns raised by the BMPs and WPSC are misplaced.

Regarding the concerns of the BMPs and WPSC about the potential decline of solar ELCC from 50%, Mr. Jester posits that “[a]lthough MISO has had discussions about adjusting solar’s

ELCC as part of its future shift to a seasonal capacity market, no such proposal has been finalized nor submitted for FERC [Federal Energy Regulatory Commission] approval." 10 Tr 4365. Mr. Jester notes that a MISO stakeholder process subcommittee has been using modeling assumptions including an "ELCC of 50% through 2026, and with the ELCC linearly declining in subsequent years until it hits 20% in 2041." 10 Tr 4365-4366 (footnote omitted). In his footnote, Mr. Jester elaborates that "[f]or the previous year's analysis, the subcommittee modeled a decline to 30%, which may be where Mr. Polich got his figure." 10 Tr 4366, n. 51. However, Mr. Jester opines that "[t]his modeling document does not undercut the reasonableness of the settlement agreement[,]" providing that "this document is simply describing a modeling analysis; it does not reflect a policy change." 10 Tr 4366. Mr. Jester also provides that "accreditation for each solar facility begins at 50% until operational records from that facility become available, after which it is based on average production during the hours of 2pm to 5pm ET in the months of June, July, and August." 10 Tr 4366 (footnote omitted). Mr. Jester argues that this distinction is important as "there is on-the-ground evidence in Michigan that the ELCC for solar facilities may be much higher." 10 Tr 4367. Specifically, "Consumers currently has three solar facilities whose MISO capacity credit ranges between 56.67% and 67%." 10 Tr 4367 (footnote omitted). Finally, Mr. Jester notes that "although the ELCC of new solar may decline if solar achieves high levels of penetration in Michigan, that effect can be mitigated, and this dynamic will not affect the capacity provided by solar deployed in the earlier years of Consumers' resource plan." 10 Tr 4367.

2. <u>Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar</u>

Kevin Lucas, Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association (SEIA), responds to the direct settlement testimony of WPSC on behalf of the CEOs. Mr. Lucas responds to the assertion by WPSC's witness, Mr. King, that the solar capacity sought by Consumers "will not be available by 2025 due to the current United States Department of Commerce . . . investigation regarding avoidance of tariffs from Chinese-made solar cells." 10 Tr 4382. Mr. Lucas provides that "the DOC is investigating whether solar imports from Cambodia, Malaysia, Thailand, and Vietnam are circumventing antidumping and countervailing duties on Chinese-made crystalline silicon cells" and further, "[i]f imposed, tariffs would increase the cost of solar products from these countries 50-250% . . . ." 10 Tr 4382. Mr. Lucas avers that "[b]ecause of the uncertainty surrounding pricing of solar panels due to the retroactive nature of potential tariffs, panel shipments to the US have largely frozen since DOC initiated its investigation. This in turn impacts projects that are under construction and planned to come online in the near future as they are unable to secure a supply of solar panels." 10 Tr 4383. However, Mr. Lucas posits that "SEIA believes the current supply chain issue is largely short-term and that it will be mitigated when a decision is reached and as domestic manufacturing capacity comes online." 10 Tr 4384. Thus, Mr. Lucas concludes that Mr. King's arguments are not supported by analysis and "[w]hile there may be some projects in Michigan that experience schedule impacts from the DOC investigation, these impacts are concentrated in the relatively near-term period." 10 Tr 4384.

3. <u>The Commission Staff</u>

Mr. Proudfoot, on behalf of the Staff, responds to the direct settlement testimony of Energy Michigan and WPSC. Mr. Proudfoot limits his rebuttal testimony to the issues of the resource acquisition methodology of the one-time solicitation, resource adequacy, and the application of the settlement agreement factors outlined in Rule 431(5) parts (b) and (c). Addressing Mr. Zakem's concerns that the settlement agreement does not require that the 500 ZRCs acquired through the one-time solicitation be additional resources to those present in Zone 7, Mr. Proudfoot posits that

"Mr. Zakem fails to recognize that Subsection 6.b.1. does not require the 500 ZRCs to be pre-existing (already counted towards MISO Zone 7 resource adequacy)." 10 Tr 4404. Mr. Proudfoot notes that under the terms of the settlement agreement, these resources will be competitively bid, thus "respondents to the solicitation could be from some of the projects currently in the MISO Queue (ITC Transmission, Michigan only) that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3." 10 Tr 4404 (footnote omitted).

Mr. Proudfoot states that, in contrast to the RFP conducted by the company in its IRP filing which was limited to pre-existing gas resources within Zone 7, "the Company is now requesting dispatchable, non-intermittent resources (not specifically gas) with no requirement to be pre-existing." 10 Tr 4404. Mr. Proudfoot argues that "between existing projects and the intermittent and dispatchable projects in the MISO Queue, there is opportunity to add new capacity within MISO Zone 7." 10 Tr 4404. Mr. Proudfoot also notes that in the second tranche of the one-time solicitation provided for in subsection 6.b.1.ii of the settlement agreement, "the Company will request 200 ZRCs from unaffiliated third parties via Power Purchase Agreements (PPAs) for intermittent and dispatchable resources." 10 Tr 4405. Thus, Mr. Proudfoot concludes that "[b]etween the two tranches, the Settlement Agreement provides the opportunity for a wide variety of new resources to bid in and ultimately be built within MISO Zone 7 . . . ." 10 Tr 4405.

Mr. Proudfoot responds to resource adequacy concerns made by Energy Michigan and WPSC. Mr. Proudfoot asserts that the settlement agreement is "a resource adequacy improvement over the Company's original PCA." 10 Tr 4405. Mr. Proudfoot cites the key difference between the resource adequacy of the company's original PCA and the settlement agreement to be the delayed retirement of Karn Units 3 and 4. Mr. Proudfoot explains that the original PCA called for the retirement of Karn Units 3 and 4 by May 31, 2023, while the settlement agreement delays the retirement until May 31, 2031. Mr. Proudfoot posits that Consumers "was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7" while the settlement agreement "only retires a portion of that amount, approximately 1500 MW . . . ." 10 Tr 4405. Further, Mr. Proudfoot notes that along with the commitment to retire the entire Campbell plant, Consumers "is proposing to add approximately 1176 MW to Zone 7 through the acquisition of the Covert Power Plant." 10 Tr 4405. Further, Mr. Proudfoot provides that Consumers "continues its solar build out and is expected to add 300 MW of solar resources in 2023, 500 MW of solar resources in 2024, and 500 MW of solar resources in 2025[,]" noting that under the current MISO ELCC construct, "that is approximately 400 ZRC's [sic] of new resources within MISO Zone 7." 10 Tr 4406 (footnote omitted). Mr. Proudfoot adds that the one-time solicitation for 700 MW set forth in the settlement agreement is additional to the resources outlined above. 10 Tr 4406. Mr. Proudfoot concludes that the "Staff does not believe the [settlement agreement] is likely to result in the Company being short on capacity in 2025." 10 Tr 4406. Mr. Proudfoot opines that the 7.4% reserve margin used by Consumers in its Capacity Demonstration in Case No. U-21099 is reasonable as it "comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report." 10 Tr 4406 (footnote omitted).

Regarding Rule 431(5)(a), Mr. Proudfoot testifies that all parties have been given an opportunity to present arguments in opposition to the settlement agreement through direct and rebuttal testimony. 10 Tr 4407. In regard to Rule 431(5)(b) and (c), Mr. Proudfoot asserts that the "Staff believes that Consumers has adequately met its requirements under [Public Act] 341 of 2016 . . . and provided a reasonable revised PCA." 10 Tr 4407. Mr. Proudfoot posits that not only did Consumers and the Staff sign the settlement agreement, but so did other parties who represent residential customers (the Attorney General, CUB, and Urban Core Collective); commercial and industrial customers (HSC, MCV, and MPPA); businesses in Michigan's advanced energy sector (EIBC/IEI/CGA); environmental groups (MNS and the CEOs); a transmission company (METC); and third-party developers (GLREA). 10 Tr 4407-4408. Mr. Proudfoot opines that the signatories to the settlement agreement "represent most, if not all, of Michigan's sectors concerned with the future of energy related issues." 10 Tr 4408. Mr. Proudfoot concludes that "it is Staff's opinion that this [settlement agreement] meets the requirements of Rule 431." 10 Tr 4408.

4. Biomass Merchant Plants

Mr. Polich, on behalf of the BMPs, filed rebuttal testimony to reassert his position that the continued operation of the biomass plants fosters resource adequacy and contributes to Consumers goal of being carbon neutral by 2040. 10 Tr 4289. Mr. Polich takes the position that "it is in the Public Interest for the continued utilization of the Biomass Plants to be incorporated into the [s]ettlement [agreement] by extending their contracts through at least 2035" as it will "help alleviate Consumers' capacity deficiency that occurs in several years of 2025 through 2038 . . . ." 10 Tr 4289. Mr. Polich poses that there are "significant risks associated with adding 7,800 MW of solar capacity as proposed[,]" including the magnitude of the capacity; the possible lowering of MISO's current 50% solar accreditation; and MISO interconnection, development, financing, and construction risks. 10 Tr 4290-4291. Mr. Polich also notes the settlement agreement's "reliance on natural gas generation as the only form of non-intermittent generation to supplement the renewable generation." 10 Tr 4291.

Mr. Polich responds to MNS' position that the settlement agreement improves upon Consumers' initially filed PCA by eliminating the purchase of certain gas plants from Consumers' affiliate CMS Enterprises. Mr. Polich asserts that "[s]ince the only bidders in the One-Time Solicitation first tranche will likely be existing generation, the bidders will be the same entities that bid into Consumers' solicitation that resulted in three CMS plants being successful bidders." 10 Tr 4292. Mr. Polich also responds to Mr. Jester's testimony that the second tranche of the one-time solicitation is beneficial to the public interest. Mr. Polich argues that "the timing of the solicitation and 2025 in-service date will limit bidders to those with MISO interconnection agreements, preliminary engineering, major equipment under contract, and rights to construction sites already procured" adding that "it is highly unlikely any generation project can be constructed by the summer of 2025 in-service date." 10 Tr 4293.

5. Wolverine Power Supply Cooperative

Mr. King, on behalf of WPSC, responds to the direct testimony of MNS and the BMPs. Mr. King focuses his testimony on Mr. Jester's claims regarding "the clear reliability deficiencies resulting from the proposed: (1) one-time solicitation; (2) retirement dates for Campbell Unit 3 and Karn Units 3 and 4; and (3) transmission considerations." 10 Tr 4311. Additionally, Mr. King focuses on Mr. Polich's "statements identifying Zone 7 and Consumers as import dependent." 10 Tr 4311.

Mr. King disagrees with Mr. Jester's position that "the one-time solicitation of 700 ZRCs contemplated in the disputed [settlement] agreement is a reasonable and beneficial settlement [agreement] term sufficient to replace the retirement of Campbell Unit 3." 10 Tr 4311. Mr. King reasserts that "500 of the 700 ZRC[s] are unlikely to result in any new capacity to Zone 7 due to the solicitation requirements being 'dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year…[in] Zone 7.'" 10 Tr 4312 (quoting Settlement Agreement, p. 6). Mr. King further provides that "only the CMS plants, or a portion thereof, are available today in Zone 7. And nothing new exists in MISO's interconnection queue." 10 Tr 4312. Mr. King posits that, "the second tranche of 200 ZRCs are likely to be procured from intermittent resources . . . because much like Tranche 1, there are unlikely any nonintermittent resources available today or in the MISO interconnection queue." 10 Tr 4312. Mr. King asserts that there are reliability implications if the CMS plants are the only resources available to participate in the one-time solicitation. Specifically, "[r]eplacing Campbell Unit 3 with existing Zone 7 capacity produces a net negative capacity position in the Zone." 10 Tr 4312.

Mr. King opines that by supporting the retirement of Campbell Unit 3, Mr. Jester, "fails to analyze, or even consider, the public health and safety impacts resulting from lower reliability." 10 Tr 4313.

Mr. King addresses Mr. Jester's position that delaying the retirement of Karn Units 3 and 4 from 2023 to 2031 is a reasonable and beneficial settlement term. Mr. King argues that "[w]hile the continued operation of existing resources is prudent in order to maintain reliability, extending the retirement date for Karn Units 3 and 4 does not appear to be a reasonable or prudent path as the units are, [sic] less reliable and provide insufficient additional capacity." 10 Tr 4314. Specifically, Mr. King provides that the settlement agreement proposes to extend the operation Karn Units 3 and 4 which have an installed capacity of 1,120 MW and accredited capacity of 790 MW (70.5% accredited) while continuing to expedite the retirement of the Campbell Units which have an installed capacity of 1,393 MW and an accredited capacity of 1,346 MW (96.6% accredited). 10 Tr 4314.

Mr. King refutes Mr. Jester's testimony supporting the settlement terms that require Consumers to consider the reliability and economic value of transmission in its next IRP to access resources outside Zone 7. Mr. King posits that this consideration must happen sooner than Consumers' next IRP as "Zone 7 is already import reliant in the upcoming 2022/23 Planning Year (and has been for seven of the last nine capacity auctions) to meet its PRMR . . . ." 10 Tr 4314.

Mr. King avers that "[w]hen Consumers and Zone 7 are import reliant . . . [i]f one of a few existing ties fails or export capability (elsewhere) is reduced (e.g., retirements or forced outage), proportional load shed is the next step." 10 Tr 4315.

Finally, Mr. King encourages improving access to external resources. 10 Tr 4315. Mr. King posits that "Michigan should demand greater, more resilient, and more diverse ties to the greater market/grid." 10 Tr 4315.

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

EIBC/IEI/CGA presented the rebuttal testimony of Edward Burgess, the Senior Director at Strategen Consulting. Mr. Burgess responds to the direct testimony of Mr. Polich on behalf of the BMPs on "timing delays and other risks associated with solar development[,]" specifically, that the settlement "simply ignores risks associated with intermittent solar generation." 10 Tr 4388-4389 (footnote omitted). Mr. Burgess opines that the settlement addresses some of these potential risks by turning them into opportunities, such as better utilization of Michigan manufactured components and low-carbon manufacturing. 10 Tr 4389. Mr. Burgess rebuts Mr. Polich's position that the one-time solicitation outlined in the settlement agreement is flawed. Mr. Burgess posits that Mr. Polich's assumptions that "the second tranche procurement Settlement Paragraph 6.b.ii 'will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of material'" is an improper reading of the settlement [agreement]. 10 Tr 4389-4390 (quoting 10 Tr 4281) (footnote omitted). Mr. Burgess asserts that "[t]he fact that the 'duration of the contract length' will be taken into account for all new supply side resources, including solar and battery storage capacity options, will enable especially battery storage capacity options to be evaluated on par with intermittent resources in terms of the full price of the contract." 10 Tr 4390 (quoting Settlement Agreement, p. 6). Further, Mr. Burgess adds that "the fact that the solicitation is tailored towards ZRCs that meet the Local Clearing Requirements of MISO Zone 7 means that it already inherently accounts for any intermittency concerns through the MISO capacity accreditation process." 10 Tr 4390.

Finally, Mr. Burgess posits that the technology neutral language of the one-time solicitation in section 6.b.ii of the settlement agreement rectifies concerns that Consumers' initial PCA "did not adequately model nor otherwise address the potential inclusion of battery storage resources." 10 Tr 4391.

7. Consumers

Consumers presented the rebuttal testimony and exhibits of Richard T. Blumenstock, Thomas P. Clark, and Michael A. Torrey. Each witness' testimony will be addressed here in turn.

Mr. Blumenstock, Executive Director of Electric Supply at Consumers, focuses his rebuttal testimony on responding to assertions raised by Energy Michigan, WPSC, and the BMPs.

Mr. Blumenstock provides an overview of how the settlement agreement aligns with subsection 6t(8)(a)(i-vii) of Act 341, MCL 460.6t(8)(a)(i-vii), on pages 7-15 of his rebuttal testimony.

Mr. Blumenstock responds to the testimony of Energy Michigan's witness Zakem by claiming:

> Energy Michigan is continuing to rely on its direct testimony as previously submitted in this case before the Settlement Agreement was reached . . . . The problem with that approach is that Mr. Zakem's direct testimony was focused on the Company's purchase of the Dearborn Industrial Generation ("DIG"), the Kalamazoo River Generating Station ("Kalamazoo"), and the Livingston Generating Station ("Livingston") plants . . . and the Settlement Agreement no longer provides for the purchase of those plants in the manner initially proposed by the Company. Mr. Zakem has also made no adjustment to his initial position to account for the fact that the Settlement Agreement continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially proposed by the Company.

10 Tr 4128-4129. Thus, Mr. Blumenstock posits that Mr. Zakem's assessment "no longer accurately describes the elements of the PCA, as modified by the Settlement Agreement."

10 Tr 4129. Mr. Blumenstock also claims that Mr. Zakem's position that the one-time solicitation provided for in the settlement agreement may result in resources that are already being counted toward resource adequacy requirements in MISO Zone 7 is speculative. 10 Tr 4129.

Mr. Blumenstock responds to WPSC's arguments on purported reliability issues that Mr. King claims are at risk in the settlement agreement. Addressing Mr. King's argument that Consumers will likely be capacity negative in 2025, Mr. Blumenstock argues that the 28 ZRC capacity shortfall Mr. King calculated is insignificant as "a small magnitude surplus *or* shortfall can shift over a relatively short period of time. This is why the Company implements a strategy of maintaining approximately 200 ZRCs of capacity surplus." 10 Tr 4131 (emphasis in original). Mr. Blumenstock posits that Mr. King's capacity position calculation is also flawed as it "relies on the <u>exclusion</u> of capacity acquired through the one-time solicitation . . ." 10 Tr 4131 (emphasis in original). Mr. Blumenstock further provides that Mr. King's "claim that the Company could be capacity negative in 2025 would assume the Company is wholly unsuccessful in its one-time solicitation—that 0 ZRC of capacity are acquired through a Request for Proposals soliciting up to 700 ZRCs." 10 Tr 4131. Mr. Blumenstock avers that Mr. King's testimony fails to explain how the equalization adjustment factor used in his capacity position is calculated or appropriately used. 10 Tr 4133.

Mr. Blumenstock responds to the BMPs' testimony by Mr. Polich that "the Company did not appropriately consider biomass plants in this IRP . . . ." 10 Tr 4135. Mr. Blumenstock opines that "the Company is not under any obligation to enter new PPAs with the BMPs or extend the BMPs' existing contracts." 10 Tr 4135. Mr. Blumenstock asserts that "the Company did consider biomass plants in the development of the IRP. The Company considered biomass plants as it began its modeling process, but due to the fact that those resources were not viable options on an economic or cost basis, biomass plants did not pass the Company's resource screen process. 10 Tr 4136. Mr. Blumenstock notes that "the plants which make up the BMPs are included in the PCA through the end of their current PPA terms." 10 Tr 4136. Mr. Blumenstock opines that "the flaw in the BMPs' position is that the Company did not have adequate information to determine the cost of new PPAs or PPA extensions with the BMPs in the development of this IRP" and "throughout this proceeding, the BMPs have failed to produce any evidence in the record establishing the costs that the BMPs could agree to in new PPAs or PPA extension[s]." 10 Tr 4136.

Mr. Blumenstock addresses Mr. Polich's testimony making recommendations to the proposed settlement agreement, arguing that "Paragraph 22 of the Settlement Agreement provides that if the Commission rejects or modifies the Settlement Agreement or any provision of the Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn." 10 Tr 4137. Mr. Blumenstock also asserts that the BMPs' requested modifications to the settlement agreement are "beyond the scope of this contested settlement." 10 Tr 4138.

Mr. Blumenstock responds to Mr. Polich's claims that the settlement agreement will result in Consumers having "excess capacity between 2023 and 2030 and capacity shortages between 2031 and 2038." 10 Tr 4139. Mr. Blumenstock elaborates that "the Purchase Sale Agreement ('PSA') for [the Covert] plant provides for the purchase in 2023" and "Mr. Polich has also not established that the Company has any ability to move the start date of the Covert Plant purchase." 10 Tr 4140. Further, Mr. Blumenstock posits that "even if the Covert Plant does provide surplus energy and capacity for a short period, the Company can monetize the energy and capacity of the Covert Plant by selling it into the MISO markets and using the resulting revenue to lower power supply costs to the benefit of customers." 10 Tr 4141. Responding to Mr. Polich's assertion that the one-time solicitation is not needed until 2030, Mr. Blumenstock opines that:

> the one-time solicitation included in the proposed Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent and non-intermittent clean resources will provide sufficiency of supply to support retirement of the Campbell Units. However, until such resources are acquired and operational on behalf of customers, the Settlement Agreement provides for continued operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of customers. The continued operation of Karn Units 3 and 4 further addresses reliability concerns for customers.

10 Tr 4141. Mr. Blumenstock concludes that "[b]ecause the one-time solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for continued operations of Karn 3 and 4 can be assessed in the future, the BMPs have not established that the one-time solicitation is unnecessary or to the detriment of customers." 10 Tr 4141-4142,

Mr. Blumenstock rebuts Mr. Polich's claim that the settlement agreement will result in a capacity shortfall position in the years 2031 through 2038. Mr. Blumenstock explains that "Mr. Polich suggests that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity shortfalls eight years into the future." 10 Tr 4142 (emphasis in original). Mr. Blumenstock posits that "the PCA was developed using current MISO solar capacity accreditation practices." 10 Tr 4142. Mr. Blumenstock opines that "[w]hile discussions in MISO have raised the possibility of changes to solar capacity accreditation, it would be premature to adopt such changes ahead of MISO itself issuing the rule change." 10 Tr 4142. Further, Mr. Blumenstock provides that "at the Company's existing solar facilities, capacity accreditation, based on actual performance, has been as high as 65%" and "[w]hile the possibility of lowering the accreditation is under consideration, actual performance will ultimately dictate the levels of capacity customers receive from these resources." 10 Tr 4142. Additionally, Mr. Blumenstock notes that Mr. Polich's projected capacity shortfall is to occur eight years in the future. Mr. Blumenstock avers that Consumers "will file at least one, if not multiple IRPs between now and that time. If changes to solar accreditation occur at MISO, the Company has ample time to respond and adjust the PCA." 10 Tr 4143-4144.

Mr. Blumenstock responds to Mr. Polich's arguments that the one-time solicitation proposed in the settlement agreement is "deeply flawed." 10 Tr 4144; 10 Tr 4289. In response to Mr. Polich's claims that "the one-time solicitation will favor existing generation facilities[,]" specifically due to "engineering, financing, and construction time limitations, as well as delays in the MISO interconnection process[,]" Mr. Blumenstock "disagrees that this is a flaw in the design of the solicitation." 10 Tr 4144. Mr. Blumenstock posits that "the resources acquired in the one-time solicitation will help replace the capacity and energy lost by Campbell Units 1, 2, and 3 in 2025" and "[f]urthermore, beyond speculating what plants can participate, Mr. Polich fails to establish anything unreasonable about the solicitation." 10 Tr 4144. Mr. Blumenstock avers that the resources sought in the one-time solicitation are consistent with the modeling presented by the company in its principal case.

In response to Mr. Polich's argument that Consumers chose to exclude the BMPs from its IRP, Mr. Blumenstock avers that the settlement provides that the first tranche of the solicitation requires "dispatchable, nonintermittent generation *capable* of dispatching up or down in every hour of the year in response to wholesale energy market signals." 10 Tr 4146 (emphasis in original) (quoting Settlement Agreement, p. 6); *see also*, 10 Tr 4272. Mr. Blumenstock argues that Mr. Polich has asserted throughout these proceedings "that the BMPs' 'generation facilities can provide *around the clock*, renewable, *dispatchable* and reliable power generation.'" 10 Tr 4146 (emphasis in original) (quoting 7 Tr 2684). Mr. Blumenstock concludes that Mr. Polich's testimony with regard to the fact that the BMPs are dispatchable has been inconsistent. 10 Tr 4146. Additionally, Mr. Blumenstock provides that "certain BMPs are offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis. Since the MISO Day-Ahead Market clears the day prior to operation, the plants are provided dispatch notice prior to actual operation." 10 Tr 4147.

Mr. Blumenstock rebuts Mr. Polich's claim that the term "clean capacity resources," is not defined in the settlement agreement. Mr. Blumenstock asserts that "[t]he Company's generation portfolio includes fossil fuel and clean capacity resources such as solar and hydro generation." 10 Tr 4147. Mr. Blumenstock provides that "[t]he Settlement Agreement specifically provides that '[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources *(including battery storage resources)* <u>providing capacity which meets the Local Clearing Requirement of MISO Zone</u> 7.'" 10 Tr 4148 (emphasis in original) (quoting Settlement Agreement, p. 6). Mr. Blumenstock argues that "[s]ince the Settlement Agreement provides 'battery storage resources' as an example of the 'dispatchable, nonintermittent clean capacity resources' that can participate in the second tranche, the Settlement Agreement is not 'very ambiguous,' as Mr. Polich claims." 10 Tr 4148 (citing 10 Tr 4280).

Mr. Blumenstock addresses Mr. Polich's arguments that the one-time solicitation "'will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity'" and "'volatility of natural gas pricing.'" 10 Tr 4148 (quoting 10 Tr 4281). Mr. Blumenstock dismisses Mr. Polich's arguments as speculation and asserts that Consumers witness Brian D. Gallaway addressed gas prices in the initial record of this case and "established that gas price volatility is not expected to continue into the future." 10 Tr 4148. Further, Mr. Blumenstock asserts that "the Company will have an incredibly diverse resources portfolio that includes: pumped storage and hydro generation, gas generation, wind generation, solar generation, energy efficiency, DR, and emerging technologies such as grid modernization and battery storage to meet the future demand of its customers." 10 Tr 4148-4149. Mr. Blumenstock also posits that "[t]he Company maintains PPAs with numerous technology types." 10 Tr 4149.

Mr. Blumenstock addresses Mr. Polich's final concern with the one-time solicitation, that the one-time solicitation will result in "'only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials.'" 10 Tr 4149 (quoting 10 Tr 4281). Mr. Blumenstock again dismisses this argument as speculation and opines that "[t]he one-time solicitation is a competitive bidding process which will consider the value of the resources which are bid. If certain resources are 'too expensive,' as Mr. Polich claims, that issue will naturally be resolved through the ranking of eligible bids." 10 Tr 4149.

Addressing Mr. Polich's testimony that the settlement agreement does not meet the intent of being carbon neutral by 2040 as stated in the settlement agreement, Mr. Blumenstock replies that "[p]aragraph 16 of the Settlement Agreement merely reiterates that the Company's filed IRP 'set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025.'" 10 Tr 4149 (quoting Settlement Agreement, p. 13). However, Mr. Blumenstock posits that "there is nothing in the Settlement Agreement that will necessarily impede the Company's ability to meet its goal." 10 Tr 4149. Further, Mr. Blumenstock provides that "the 20-year capacity plan provided by the Company in this IRP assumed cessation of the Covert Plant by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets." 10 Tr 4150.

Turning to Mr. Polich's assertion that Karn Units 3 and 4 could be designated as a system support resource (SSR) by MISO, Mr. Blumenstock posits that "[a]n SSR designation would not be due to a capacity or energy shortfall. An SSR designation would result from an electric transmission system deficiency that must be mitigated before Karn Units 3 and 4 could be retired." 10 Tr 4152. Mr. Blumenstock avers that "Karn Units 3 and 4 will continue to operate to ensure near-term reliability for the benefit of Consumers Energy customers. These units may be operated through May 31, 2031, depending on the Company's capacity needs and the outcome of the Company's resource procurement efforts." 10 Tr 4152. Mr. Blumenstock also provides that the cost burden associated with designating Karn Units 3 and 4 as SSR units would shift to the entirety of Zone 7 and would thus not pose an increased risk to customers. 10 Tr 4152.

Mr. Blumenstock concludes that Energy Michigan, WPSC, and the BMPs have not established any basis for the Commission to reject the settlement agreement. 10 Tr 4154.

In his rebuttal testimony, Mr. Clark responds to claims raised by Energy Michigan, WPSC, and the BMPs. Specifically, Mr. Clark focuses his rebuttal testimony on: (1) reliability concerns raised by these witnesses in connection with Consumers' retirement of Campbell Unit 3; (2) the potential volatility of MISO's capacity planning process and its impact on the company's customers; (3) claims that the settlement agreement fails to address the forthcoming MISO seasonal capacity construct; (4) claims that the settlement agreement will impact reliability for residents in the lower peninsula and result in a capacity shortfall between 2031 and 2038; and (5) claims regarding competitive pricing in Michigan resulting from the settlement agreement. 10 Tr 4223.

Mr. Clark responds to Mr. King's positions on behalf of WPSC with regard to the company's projected solar capacity additions and their accreditations. Mr. Clark posits that the company is confident that its solar capacity expansion will be successful despite issues with supply chain and local zoning and "to the extent that the Company experiences minor delays beyond the 2025-2026 planning year, it continues to have sufficient capacity to reliably serve its load as a result of the continuing operation of Karn Units 3 and 4 and the one-time solicitation proposed in the Settlement Agreement." 10 Tr 4227. With respect to a potential reduction in solar capacity accreditation, Mr. Clark opines that "the current ELCC is 50% of a solar generator's installed capacity, and there is no certainty of timeline for a reduction from the current MISO practice." 10 Tr 4227.

Mr. Clark rebuts Mr. King's testimony "that a continued reduction to the Company's PRMR is not reasonable," stating that "[w]hile the Company's forecasted load may be increasing, the Company's internal waste reduction and demand response programs are also increasing, thereby offsetting a large portion of the growth." 10 Tr 4227. Mr. Clark adds that "the planning reserve margin ('PRM') provided by MISO is decreasing, thereby allowing the Company's PRMR to decrease rather than increase." 10 Tr 4227-4228 (footnote omitted). Mr. Clark provides that "[t]he Company's most recent capacity demonstration filing reflects that the PRM provided by MISO dropped from 8.70% for planning year 2022-2023 to 7.40% for planning year 2025-2026." 10 Tr 4228 (footnote omitted). Mr. Clark notes that "[t]he Planning Year 2022-2023 Loss of Load Expectation Study Report indicates that the 2025-2026 planning year PRM decreased slightly from the 2022-2023 planning year PRM primarily based upon expected new unit additions." 10 Tr 4228.

Addressing Mr. King's argument that Consumers' IRP is "based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources[,]" Mr. Clark posits that "the Company has projected sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation." 10 Tr 4228 (quoting 10 Tr 4302-4303). Mr. Clark opines that "neither a short delay in the onboarding of this additional capacity nor a lack of available additional economic capacity would have a material, detrimental impact to the Company's immediate capacity position[,]" which would be reviewed subsequently in later IRP filings. 10 Tr 4229.

Mr. Clark responds to Energy Michigan's testimony from Mr. Zakem that "the Settlement Agreement will impact resource adequacy and the competitive market because the 500 ZRCs of dispatchable capacity that the company is seeking via solicitation will not necessarily be in addition to what is already being counted toward LRZ 7's resource adequacy requirements." 10 Tr 4229. Mr. Clark argues that "Consumers Energy, like all other LSEs, is responsible for ensuring that it has adequate supply to meet its customers' needs." 10 Tr 4229. Mr. Clark posits that "the Company has a requirement to serve its own customers' load while meeting applicable MISO requirements. The Company does not have an obligation to ensure LRZ 7 has adequate capacity for all LSEs to meet their customers' supply needs." 10 Tr 4229.

Addressing Mr. Zakem's concerns that the settlement agreement is anti-competitive, Mr. Clark adds that:

> Other LSE's, [sic] like Energy Michigan's AES [alternative electric supplier] members maintain the obligation to serve their own load and to ensure equitable contribution to reliability requirements. Consumers Energy is not responsible to provide a reliability backstop for the benefit of AESs unless the requirement to provide backup capacity is triggered by an AES's failure to meet its own four-year forward capacity obligations as required under Public Act 341 of 2016.

10 Tr 4230. Mr. Clark avers that "[o]ther LSEs have been aware of the Company's PCA since June of 2021[,] which has provided ample time to secure resources they may need to satisfy their own capacity obligations." 10 Tr 4231. Further, Mr. Clark argues that "the Company has not issued the one-time solicitation yet and therefore, other LSEs continue to have the opportunity and ability to secure resources they may need to satisfy their own capacity obligations prior to the issuance of the one-time solicitation." *Id*. Mr. Clark posits that "[b]ased on Staff's March 25,

2022 Capacity Demonstration Results report[2] filed in Case No. U-21099, all LSEs met their filing requirement detailing how the necessary capacity resources will be met for the Planning Year 2025-2026 (with one exception)." *Id*. (footnote omitted). Mr. Clark opines that "since all LSEs provided capacity projections through Planning Year 2025-2026, the 500 ZRCs of capacity that the Company will solicit for starting in 2025 should have no impact on an LSE who should have already committed capacity for the Planning Year 2025-2026." 10 Tr 4231.

Mr. Clark then turns to the assertion of Mr. King on behalf of WPSC and Mr. Zakem on behalf of Energy Michigan on the impact the settlement agreement will have on resource adequacy. Mr. Clark avers that neither party provided specific information showing reliability risks to WPSC or Energy Michigan's members. 10 Tr 4233.

C. <u>Initial Briefs</u>

1. <u>Energy Michigan</u>

Energy Michigan contends that the Commission is required to determine that an electric utility's IRP "represents <u>the most</u> reasonable and prudent means of meeting the electric utility's energy and capacity needs." Energy Michigan's initial brief, pp. 1-2 (quoting MCL 460.6t(8)(a)) (emphasis in original). Energy Michigan further posits that Rule 431 requires that for approval of a proposed contested settlement agreement, the Commission must find that "the settlement is in the public interest, represents a fair and reasonable resolution to the proceeding, and, if the settlement is contested, is supported by substantial evidence on the record as a whole." Energy Michigan's initial brief, p. 2 (quoting Rule 431(5)(c)). Energy Michigan avers that "[t]he Commission's administrative rules may not overrule the underlying statute." Energy Michigan's

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[2] Consumers testimony references the Capacity Demonstration Results which can be accessed on the Commission's website at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002Qy56AAC (accessed June 6, 2022).

initial brief, p. 2. Energy Michigan argues that "when a statute and an administrative rule conflict, the statute necessarily controls. While administrative agencies have what have been described as 'quasi-legislative' powers, such as rulemaking authority, these agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature." *Id*. (quoting *Emagine Entertainment, Inc v Dep't of Treasury*, 334 Mich App 658, 664; 965 NW2d 720 (2020)). Energy Michigan posits that under this precedent, the Commission must consider whether the IRP appropriately balances the factors enumerated under Section 6t(8)(a) of Act 341, including: (1) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (2) reliability; and (3) competitive pricing. Energy Michigan's initial brief, pp. 2-3 (citing MCL 460.6t(8)(a)(i)(iii-iv)). Energy Michigan argues that "[b]ecause Consumers' proposed settlement [agreement] would have a detrimental effect on resource adequacy, reliability and competitive pricing in Michigan, the Commission should reject Consumers' proposed Settlement Agreement." Energy Michigan's initial brief, p. 3.

Energy Michigan asserts that the proposed settlement agreement fails to meet the standards set forth in Section 6t(8) of Act 341 and is not in the public interest. *Id*. Energy Michigan cites to the record to demonstrate that "the Company is proposing to solicit capacity from wholesale generators that may exist in LRZ 7." *Id*. (quoting 10 Tr 4229). Energy Michigan argues that changing ownership of resources that already exist in Zone 7 to meet Consumers' capacity needs "has adverse effects on resource adequacy, reliability, and competitive pricing." Energy Michigan's initial brief, p. 3. Energy Michigan argues that while Consumers "does not believe that it has any responsibility for the rest of Michigan (*i.e*., LRZ 7)[,]" the Commission "has a statutory responsibility to consider resource adequacy and reliability under the requirements of Section 6t." *Id*., pp. 3, 4.

Energy Michigan opines that if the one-time solicitation proposed in the settlement agreement is necessary, "the acquisition of 500 MW of existing in-zone capacity would not actually contribute to resource adequacy . . . ." *Id*., p. 4. Additionally, Energy Michigan posits that if Consumers does not need the capacity represented by the one-time solicitation, "that solicitation is not the most reasonable and prudent means of meeting the utility's capacity needs, as it would lead to an oversupply" and thus "has the potential to cause a market power issue." *Id*.

Finally, Energy Michigan "disputes the characterization of this settlement process as involving all parties or as being open to negotiation on the concerns that Energy Michigan expressed in its testimony and briefs." *Id*., p. 5. Energy Michigan claims that it "was never invited to a settlement meeting, and Energy Michigan's comments on the draft settlement agreement were neither welcomed nor considered, as [it was] explicitly told that no changes to the draft [it was] sent would be considered." *Id*.

Thus, Energy Michigan requests that the Commission reject the proposed settlement agreement as it would negatively affect resource adequacy, reliability, and competitive pricing in Michigan. *Id*.

2. <u>Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan</u>

MNS contends that the settlement agreement meets all of the requirements of Rule 431 and should be approved.

MNS asserts that the settlement agreement is in the public interest because it results in the closure of the Campbell plant and Consumers' exit from coal generation by 2025, and this step is critical to addressing the climate crisis and complying with the MI Healthy Climate Plan as shown in Mr. Jester and Mr. Gignac's testimony. MNS' initial brief, p. 4 (citing 10 Tr 4330, 4375). MNS asserts that the settlement agreement benefits the public health in other ways as well, through the increase to solar resources, the avoidance of the construction of new gas plants, and the removal of numerous other air pollutants (in addition to carbon dioxide) which contribute to numerous premature deaths each year. MNS' initial brief, p. 5 (citing 7 Tr 2426).

MNS notes that the retirement of the Campbell plant provides cost benefits to ratepayers as well. MNS contends that the undisputed evidence in the case showed that Campbell Units 1 and 2 are uneconomic. With respect to Campbell Unit 3, responding to WPSC's argument that this closure should be delayed, MNS notes that the settlement agreement is not severable, making it impossible for the Commission to simply adjust that timeline but approve the settlement agreement. MNS argues that such a delay would be harmful to ratepayers because the retirement of Campbell in 2025 will save customers more than $150 million. MNS' initial brief, p. 8 (citing 10 Tr 4327).

MNS asserts that the settlement agreement is also in the public interest and a fair and reasonable resolution of the case because "it formalizes two important components of a cleaner grid: Consumers' solar ramp-up from its previous IRP; and faster deployment of battery storage investments . . . ." MNS' initial brief, pp. 8-9. MNS posits that Section 3 of the settlement agreement accelerates the transition to cleaner energy while reserving cost approval for later rate cases. MNS further indicates that the settlement agreement is in the public interest because it provides for stakeholder engagement prior to Consumers' first competitive solicitation for batteries (Section 3) and provides that the second tranche of the one-time ZRC solicitation will include battery storage resources (Section 6.b.ii.). Citing the testimony of Mr. Jester and Mr. Blumenstock, MNS contends that:

> Consumers' battery proposal is a fair and reasonable settlement term for three reasons: (1) it will 'bolster Consumers' maintenance of its PRMR'; (2) it will 'support resource adequacy in Zone 7'; and (3) it may 'lead to the development of new battery storage resources within Zone 7.' The addition of battery storage

> resources also addresses commodity price risks by providing ‘flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment’ and contributing to the diversification of Consumers’ generation supply. Finally, because Consumers proposed to advance its battery storage investment in response to testimony from Commission Staff, MNS, and other parties, this settlement term reflects the input of parties who represent the public interest.

MNS’ initial brief, p. 10 (quoting 10 Tr 4124, 4339).

MNS posits that the settlement agreement also benefits customers by removing the possibility of the CMS acquisitions which had affiliate transaction issues, significant costs, and significant operational risks. MNS points out that the settlement agreement also benefits ratepayers financially by providing for a 9% ROE to calculate the WACC for the Campbell regulatory asset (Section 5), which is more favorable than the 9.9% ROE approved in Case No. U-20963. MNS notes that Section 13 of the settlement agreement provides for the donations to low-income programs for the remaining term of the Campbell regulatory asset, and further provides that these funds will not be recovered from ratepayers. MNS’ initial brief, pp. 12-15 (quoting 10 Tr 4336). Thus, MNS points out, the settlement agreement facilitates the retirement of aging coal units while providing for lower costs for ratepayers and the funding of low-income bill assistance programs. MNS’ initial brief, p. 15.

MNS argues that the settlement agreement avoids the problematic aspects of Consumers’ original PCA while retaining the benefits, noting that the settlement continues the ramp up of solar PPA procurement, retains the 50/50 ownership-to-PPA ratio, and retains the existing FCM calculation. MNS also points to provisions that benefit the communities that will be affected by the Campbell retirement including community engagement and transition plans (Section 7.b.). *Id.*, pp. 16-19.

Responding to WPSC's arguments, MNS asserts that the settlement agreement will actually help improve resource adequacy. MNS notes that:

> the Settlement will add thousands of zonal resource credits (ZRCs) to Zone 7, including:
>
> • 1,114 ZRCs through the acquisition of the Covert combined-cycle gas plant;
> • a new battery storage program in the 2024-27, which will add 71 ZRCs of new capacity;
> • 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029, with further increases throughout the 2030s; and
> • 94 ZRCs of demand-side resources (EWR and DR) by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years.

MNS' initial brief, p. 20 (citing 10 Tr 4347-4350; Settlement Agreement, paragraphs 1-3; Exhibit A-14, p. 9; and Exhibit MEC-79, p. 1). MNS highlights Mr. Jester's testimony that for the 2025/2026 planning year the settlement agreement will result in an estimated net increase of 127 ZRCs, and for the 2028/2029 planning year a net increase of 923 ZRCs. MNS' initial brief, p. 20 (citing 10 Tr 4349-4350). Added to this is Consumers' obligation to seek PPAs for up to 200 additional ZRCs (Section 6.b.ii.). MNS observes that the Staff agrees that resource adequacy will be strengthened, noting Mr. Proudfoot's testimony that Zone 7 resources will increase, under the terms of the settlement agreement, by approximately 400 ZRCs by 2025. MNS' initial brief, p. 22 (citing 10 Tr 4405-4406). MNS contends that the settlement agreement thereby complies with the statutory requirement that the IRP ensure resource adequacy and capacity. MCL 460.6t(8)(a)(i). MNS also argues that Mr. Jester and Mr. Blumenstock refuted Mr. King's calculations and arguments. MNS' initial brief, p. 23 (citing 10 Tr 4354-4356, 4130-4134).

Finally, MNS points to the diversity of the parties that are signatories to the settlement agreement as evidence that the agreement is in the public interest and argues that, by comparison, the objecting parties' interests are relatively narrow. MNS asserts that Energy Michigan is a trade group with narrow business interests; WPSC is a power supply cooperative with a contractual interest in opposing the Campbell retirement; the BMPs seek only to extend their PPAs with Consumers; and Mackinac submitted no evidence and evinces only an ideological opposition to closing coal plants. MNS' initial brief, pp. 25-27. MNS argues that the settlement agreement satisfies the Rule 431 criteria and should be approved. *Id.*, pp. 27-28.

3. Mackinac Center for Public Policy

Mackinac argues that the Commission should reject the settlement agreement because it does not represent "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs" as required in the language of MCL 460.6t(8)(a). Mackinac's initial brief, p. 3 (quoting MCL 460.6t(8)(a)). Mackinac also contends that the settlement agreement does not meet the requirements of Rule 431(5) because it is not in the public interest and is not supported by substantial evidence on the record. Mackinac's initial brief, pp. 4-5.

Mackinac asserts that the settlement agreement is not in the public interest because it presents a risk of "systemwide instability and rapid price swings." *Id.*, p. 5. Mackinac states that this is partially due to the overreliance in the settlement agreement on acquiring additional power from the MISO market. Mackinac quotes from its exceptions to argue that MISO does not have sufficient capacity to serve the relevant demand. Mackinac asserts that the settlement agreement could cause reliability problems in MISO Zone 7 if early plant closures are "allowed to move forward without sufficient replacement capacity." Mackinac's initial brief, p. 7 (quoting Mackinac's exceptions, p. 7). Mackinac "acknowledge[s] that the proposed Settlement Agreement addresses this somewhat by acknowledging that Karn Units 3 and 4 may be required to stay in operation," but argues that the settlement agreement does not do enough to alleviate the concern about "systemwide instability and rapid price swings." Mackinac's initial brief, p. 8. Mackinac argues that the recent results of the MISO Planning Resource Auction for Zone 7 show the potential for a shortfall.[3]

Mackinac further states that the settlement agreement fails to consider the recent volatility of natural gas prices. Mackinac argues that natural gas plays a "heavy role" in the settlement and thus natural gas pricing should be central to the Commission's decision. *Id.*, p. 10. Mackinac again quotes extensively from its exceptions and argues that the settlement agreement fails to address the concerns that were laid out in the exceptions. Mackinac asserts that Henry Hub prices are at "near-historic levels" and that the price of coal compares favorably to natural gas. *Id.*, pp. 14-15. Mackinac asserts that "a reasonable and prudent path would be to rework the Company's modelling scenarios with more realistic natural gas prices." *Id.*, p. 15.

Mackinac further expresses concern that:

> [p]er the Proposed Settlement Agreement, the Company will spend over $30 million ratepayer dollars establishing programs specifically designed to limit customer access to electricity services during periods of higher demand (cold or hot weather): $23,751,000 for demand response programs, and $9,736,315 for conservation voltage reduction. These expenditures are deemed necessary because the Company is working from its wholly voluntary plan to reach net-zero CO2 emissions by designing a system that will be unable to meet customer demand, especially during periods of extreme weather.

Id., p. 16 (citing Settlement Agreement, p. 4). Mackinac continues, arguing that the settlement agreement fails to address the issues of restricted supply chains and significant price increases for certain minerals such as lithium, cobalt, and nickel. Mackinac posits that Consumers' planned expansion of the use of batteries will still be insufficient to provide the necessary backup power

[3] Mackinac's initial brief contains numerous links to publicly available documents sourced from governmental entities or the media. None of the referenced documents are part of the record in this case. Mackinac did not present evidence in either the primary phase or the contested settlement phase of the case.

during extended periods of inclement weather, and that, in any case, developing a sufficient level of backup battery power would be prohibitively expensive. Mackinac asserts that the settlement agreement also fails to consider the significant environmental costs associated with Consumers' goal of becoming carbon neutral by 2040, which, Mackinac insists, will add to the growing level of "industry-wide instability, insolvencies, supply chain issues, and stalled development projects in the solar and wind industries." Mackinac's initial brief, p. 19.

Mackinac states that, under Section 5 of the settlement agreement, Consumers will be transferring stranded costs associated with Campbell Units 1, 2, and 3 to ratepayers as well as decommissioning costs (after a reasonableness and prudence review). Mackinac opines that an increasing level of instability is being designed into Consumers' system through the loss of large, dispatchable generation sources which are replaced by what it refers to as "weather-dependent and non-dispatchable renewable sources." *Id*., pp. 9, 19-20.

Mackinac argues that Consumers' proposed donations to low-income programs are "a band-aid solution to the problems caused by its own decision to impose on ratepayers the cost of its wholly voluntary goal of net-zero emission by 2040 goals, as well as the systemwide costs associated with weather-dependent and variable renewable energy sources." *Id.*, pp. 20-21 (footnote omitted). Mackinac concludes that:

> The Company is developing and constructing a system that precludes the use of coal and nuclear and relies solely on wind, solar, storage, and (over the upcoming two decades) slowly decreasing levels of natural gas for actual generation of electricity services for customers. Other programs such as EWR, CVR, and demand response target reduced supply and use by customers of electricity services, not the actual provision of electric service to customers. Mackinac Center objects to these measures.

Id., p. 21.

4. <u>Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance</u>

EIBC/IEI/CGA support the settlement agreement, noting that Rule 431 encourages parties to enter into settlement agreements when possible. EIBC/IEI/CGA contend that the settlement agreement meets all of the criteria for an approvable settlement under Rule 431(5) because the objecting parties were given a reasonable opportunity to present evidence and argument in opposition; the public interest is represented by the parties who entered into the agreement; and the settlement agreement is a fair and reasonable resolution of the proceeding that is supported by substantial evidence on the record. EIBC/IEI/CGA note that discovery continued during the contested settlement phase of the case and cross-examination took place. EIBC/IEI/CGA's initial brief, pp. 5-6. They also note the testimony from the Staff regarding the cross-section of signatories to the agreement, including parties who represent residential customers, commercial and industrial customers, advanced energy sector businesses, environmental groups, a transmission company, and third-party developers. *Id.*, p. 7 (citing 10 Tr 4407-4408). EIBC/IEI/CGA note that, under Section 6.b.ii. of the settlement agreement, Consumers is making a commitment to acquiring new clean energy resources of up to 200 ZRCs through PPAs or other third-party agreements. EIBC/IEI/CGA's initial brief, p. 7.

Responding to the objection that the settlement agreement will result in serious supply chain issues, EIBC/IEI/CGA opine that the settlement agreement turns these risks into opportunities by calling for better utilization of "Michigan manufactured components and low-carbon manufacturing" in the competitive bidding process. EIBC/IEI/CGA's initial brief, p. 8 (quoting Settlement Agreement, p. 9). EIBC/IEI/CGA aver that the concerns about pricing that have been expressed by the objectors are addressed by Consumers' commitment to continue the 50/50 company-ownership to third-party ownership construct that was approved in Case No. U-20165.

EIBC/IEI/CGA's initial brief, pp. 9-10. EIBC/IEI/CGA conclude that the settlement agreement meets the requirements of Rule 431(5) and should be approved. *Id*., pp. 10-11.

5. Michigan Department of Attorney General

The Attorney General states that her primary concerns with Consumers' IRP are affordability, reliability, and the use of sustainable sources of energy. She contends that the settlement agreement addresses all three of these concerns. The Attorney General notes that the settlement agreement provides for the closure of Consumers' remaining coal plants and argues that this benefits public health and is consistent with Governor Whitmer's MI Healthy Climate Plan. Attorney General's initial brief, p. 8 (citing 10 Tr 4375, 4327-4330, and 4122).

Beginning with affordability, the Attorney General notes that evidence shows that the early retirement of the Campbell plant will save ratepayers $150 million in avoidable capital expenditures. Attorney General's initial brief, p. 9 (citing 10 Tr 4327). She argues that the settlement agreement also saves money for ratepayers by eliminating Consumers' proposal to acquire the affiliated CMS plants, which avoids the potential $515 million in immediate costs as well as future retirement costs and the unrecovered book value of Karn Units 3 and 4. Attorney General's initial brief, pp. 9-10 (citing 10 Tr 4334-4335). The Attorney General further notes that, with respect to the regulatory asset, the settlement provides for a WACC of 9.0% rather than the current ROE of 9.9%, also benefiting ratepayers. And finally, the settlement agreement provides for assistance to low-income ratepayers with direct funding of $5 million this year and another potential $2 million annually over the next 14 years. Attorney General's initial brief, p. 10.

Addressing reliability, she contends that the settlement agreement provides for adequate existing and new resources to meet capacity needs. Attorney General's initial brief, p. 11 (citing 10 Tr 4330-4335, 4406, 4224-4229, 4139, and 4142-4144). The Attorney General points to the continued availability of Karn Units 3 and 4, as well as the solicitation for PPAs that will provide up to 700 ZRCs of energy and capacity beginning in 2025. She also cites to the provision that Consumers seeks 2 additional GW of new solar energy and undertake a battery storage program. Attorney General's initial brief, p. 11 (citing 10 Tr 4339). The Attorney General further states that:

> the Settlement Agreement requires the Company to conduct certain evaluations and take other actions prior to the next IRP that can lead to benefits for ratepayers including, but not limited to, developing a distributed generation resource model; gathering input from the public before filing its next IRP; gauging interest in combined heat and power resources and model for the next IRP proceeding; providing total emissions for certain pollutants in the next IRP case; presenting PM2.5-related health impacts from power plant emissions in the next IRP case; conducting environmental justice screenings near power plants; and reporting on low-income customers['] participation in energy reduction and load reduction activities and rooftop solar adoption.

Attorney General's initial brief, pp. 11-12 (citing Settlement Agreement, pp. 12-16). The Attorney General urges the Commission to approve the settlement agreement.

6. <u>Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar</u>

The CEOs take the position that the contested settlement agreement is in the public interest and supported by record evidence. The CEOs contend that the settlement supports the public interest because: "(1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company's next IRP." CEOs' initial brief, p. 6 (quoting 10 TR 4375). The CEOs posit that "the Settlement Agreement is consistent with Governor Whitmer's MI Healthy Climate Plan, and is responsive to the urgency of addressing climate change." *Id*. The CEOs opine that the settlement agreement balances the cost to Consumers associated with retirement of its coal plants with the impacts on low-income customers. CEOs' initial brief, p. 6 (citing 10 TR 4376). The CEOs state that expert testimony in the record demonstrates avoided negative health outcomes as a benefit of the early coal plant retirements and that significant public health and environmental concerns associated with acquiring the DIG facility are avoided under the settlement agreement. CEOs' initial brief, pp. 6-7. Finally, the CEOs aver that the settlement agreement has important implications for future IRPs including the commitments to model distributed generation as a resource, conduct public health and environmental justice analyses, and provide expanded opportunities for community input and public participation. *Id*., p. 7 (citing 10 Tr 4376). The CEOs argue the Commission should find the settlement agreement to be in the public interest.

7. <u>Hemlock Semiconductor Operations, LLC</u>

HSC supports the settlement and recommends that the Commission approve it. HSC's initial brief, p. 2. HSC opines that "parties were given a reasonable opportunity to present evidence and arguments in opposition to the record." *Id*., p. 4. HSC posits that the public interest was adequately represented by parties entering into the settlement agreement as "the signatories to the Settlement Agreement represent a broad cross-section of interests . . . ." *Id*., p. 5. HSC also notes that "the Michigan Court of Appeals has affirmed a Commission determination that the public interest was adequately represented by the Staff when the Staff was a party to a contested settlement agreement." *Id*. (citing *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93094; 602 NW2d 225 (1999) (*Attorney General*). HSC opines that "all the parties who filed testimony in opposition to the settlement represent competitors of Consumers. In each case, the objecting party is seeking to advance its own particular interest, and not the public interest." HSC's initial brief, p. 6 (footnote omitted). HSC submits that the settlement agreement is a fair and reasonable resolution of the proceeding as "Consumers and others presented testimony and arguments that the Settlement Agreement reflects significant compromise by all involved" which is "evident when comparing the details of Consumers' initial PCA with the terms of the proposed Settlement Agreement." *Id*. Finally, HSC posits that the settlement agreement is supported by 315 pages of transcript and 23 exhibits while the principal record in this case consisted of 4,094 pages of transcript across 9 volumes and over 500 exhibits. *Id*., p. 7. HSC concludes that the settlement agreement "is supported by substantial evidence on the record and should be approved." *Id.*

8. <u>The Commission Staff</u>

In response to the concerns raised regarding resource adequacy, the Staff responds "that this settlement agreement appropriately balances the resource adequacy concerns of Zone 7, Consumers' need to serve the load and demand of its customers, and the benefits of Consumers' decision to work towards becoming carbon neutral by 2040." Staff's initial brief, p. 4 (citing Settlement Agreement, p. 13). The Staff notes that its testimony highlights the addition of the Covert plant and the investments in renewable generation. *Id*. The Staff notes its concerns regarding resource adequacy of Zone 7, but states that:

> it also understands that Consumers Energy is not tasked with providing resource adequacy for the entirety of Zone 7 at the sole expense of Consumers' ratepayers. Staff expects all load serving entities within MISO Zone 7 to contribute the necessary capacity to meet capacity obligations at MISO and through Michigan's State Reliability Mechanism (MCL 460.6w) and that these load serving entities will make the necessary investments to ensure that all customer needs within the zone are fully planned for. Therefore, Staff recommends that the Commission find that this settlement agreement appropriately balances the reliability needs of Zone 7 and the needs of Consumers' ratepayers.

Staff's initial brief, p. 5. The Staff reiterates that while the CMS plants "can bid into one tranche of the solicitation, the CMS [plants] are only able to bid in for the capacity they have available that is not currently contracted for" which "constitutes less than 500 ZRCs in 2025." *Id*., p. 6 (citing

Settlement Agreement, pp. 6-7; 3 Tr 138, 366). The Staff also states other resources, such as distributed energy resources, may be available by 2025, and are not currently counted within Zone 7. Further, the Staff reiterates testimony indicating "that the second tranche of the solicitation will likely result in additional new resources." Staff's initial brief, p. 6.

In response to the BMPs, the Staff states that, while the biomass plants are reliable resources, the Commission cannot modify the proposed settlement agreement to extend the PPA's to 2035, because the settlement agreement is not severable, and any modification or rejection of a provision deems the settlement agreement to be withdrawn. Further, the Staff indicates that the biomass plants are able to participate in the one-time solicitation as set forth in the settlement agreement. *See*, *id*., p. 7.

9. <u>Consumers Energy Company</u>

Consumers contends that the settlement agreement satisfies the requirements of Rule 431. Consumers' initial brief, p. 10. Consumers argues that the signatories of the settlement agreement adequately represent the public interest and reiterates testimony from its witness, Mr. Torrey, "on the nature, scope, and diversity of parties' interests . . . ." in this case. *Id*., p. 11. Consumers also quotes testimony from the Staff's witness, Mr. Proudfoot, that "the 18 parties that signed 'represent most, if not all, of Michigan's sectors concerned with the future of energy related issues,' thus satisfying the requirement that the parties represent the public interest." *Id*., p. 11 (quoting 10 Tr 4408). Consumers posits that Mr. Torrey's and Mr. Proudfoot's testimony demonstrates that "the signing parties 'represent a broad, diverse group of parties advocating for the economic and environmental interests of Consumers Energy's electric customers and the state of Michigan,' who are also focused on ensuring the Company's customers are provided with reliable electricity." Consumers' initial brief, p. 11 (quoting 10 Tr 4257).

Consumers contends that "[t]he Commission should consider the four parties that signed statements of non-objection to the Settlement Agreement in reaching a finding that the Settlement Agreement adequately represents the public interest because those parties, having had an opportunity to contest the Settlement Agreement, elected not to do so." Consumers' initial brief, p. 12. Similar to HSC, Consumers posits that "[t]he Michigan Court of Appeals has upheld the Commission's finding that a utility's and Staff's involvement in a settlement agreement can be sufficient to ensure that the public interest is adequately represented and also found that that 'participation of fewer than all interested parties in the negotiation does not mandate a conclusion that the signatories to the settlement did not represent the public interest." *Id*. (quoting *Attorney General*, p. 94). Consumers concludes that "[t]he factual circumstances presented in this proceeding meet and exceed the Commission's requirement for ensuring that the settling parties adequately represent the public interest." Consumers' initial brief, p. 12.

Consumers notes that of the four parties opposing the settlement agreement—Energy Michigan, Mackinac, WPSC, and the BMPs—only three filed testimony in the present case. *Id*., p. 13. Further, Consumers argues that "[u]nlike the broad and diverse group of parties who signed the Settlement Agreement, the three parties who submitted testimony opposing the Settlement Agreement are all business competitors of Consumers Energy." *Id*. (citing 10 Tr 4262). Consumers reiterates its testimony that:

> Energy Michigan and Wolverine would benefit financially from the opportunity created in this proceeding to procure surplus capacity to meet their own customers' needs at a lower cost than building their own. The BMPs would also benefit financially if they received contract extensions at the expense of other resources which make up the PCA. That kind of motivation represents the opposite of the public interest.

Consumers' initial brief, p. 13 (quoting 10 Tr 4263). Consumers concludes that "the broad-based coalition of parties who signed the Settlement Agreement and the parties who signed statements of non-objection are a far better representation of the public interest in this proceeding than the parties who oppose it." Consumers' initial brief, p. 13 (citing 10 Tr 4263).

Consumers argues that the settlement agreement represents a fair and reasonable resolution to the proceedings as it "represents a significant compromise that was negotiated in good faith and proposes to resolve this matter based on the positions of the parties in the record." Consumers' initial brief, p. 14. Consumers avers that the settlement agreement meets the requirements for approval set out under Section 6t of Act 341. Specifically, Consumers posits that "all 18 signing parties agree that the PCA, as provided in the Settlement Agreement, represents the most reasonable and prudent plan to meet the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons" as required by Section 6t(8)(a) of Act 341. *Id*. Consumers reiterates testimony by company witness Blumenstock on the settlement agreement's compliance with Section 6t(8) of Act 341, including how the settlement agreement: (1) ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR; (2) ensures compliance with applicable state and federal environmental regulations; (3) ensures competitive pricing; (4) ensures reliability; (5) addresses commodity price risk and ensures diversity of generation supply; and (5) proposes reasonable and cost effective levels of peak load reduction (DR, CVR, EWR). *See*, Consumers' initial brief, pp. 14-19. Consumers cites to testimony by the Staff that the company's IRP PCA as revised by the settlement agreement meets the requirements of Act 341 as additional support. Consumers' initial brief, pp. 19-20.

As noted above, Consumers argues that the settlement agreement "was supported in the extensive record created in the proceedings leading up to the filing of the Settlement Agreement, which consisted of over 4,000 pages of testimony and over 500 exhibits" as well as the additional evidence provided on the contested settlement. *Id*., p. 20. Consumers notes the position of company witness, Mr. Blumenstock, MNS, and the Staff that the settlement agreement is supported by substantial evidence in the record as a whole. Consumers quotes the Staff's testimony that:

> As stated above, the record in this case is substantial. All issues addressed in the [Settlement Agreement] have been addressed in testimony, rebuttal, brief, exceptions, and robust discovery. The [Settlement Agreement] was filed after a full record has been developed in this case. Therefore, based on all of the above, it is Staff's opinion that this [Settlement Agreement] meets the requirements of Rule 431.

Id., p. 21 (quoting 10 Tr 4408). Further, Consumers posits that "certain objecting parties have also attempted to interject issues into this contested settlement proceeding which are not based on the initial record at all." Consumers' initial brief, pp. 21-22. Specifically, Consumers references WPSC's reliance on the company's December 1, 2021 capacity demonstration in Case No. U-21099 and the BMPs' proposal that the settlement agreement be modified to require Consumers to extend their PPAs with the represented plants. *Id*., p. 22. Consumers concludes that the settlement agreement "is in the public interest, represents a fair and reasonable resolution of the proceedings, and is supported by substantial evidence on the record as a whole" and thus "it should be approved by the Commission in its entirety without and modifications or conditions." *Id*.

Turning to the arguments of the individual objecting parties, Consumers argues that these objections fail to provide grounds to reject or modify the settlement agreement. *Id*., p. 23. Consumers opines that these "arguments demonstrate a self-interested concern that the Settlement Agreement will challenge their ability to profit off Consumers Energy and its customers and Michigan's hybrid deregulation construct." *Id*. Addressing WPSC's position that the settlement agreement will negatively impact reliability, Consumers avers that the settlement agreement "will bring at least 2,084 ZRCs into MISO LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ of nearly 700 ZRCs (at least)." *Id*., p. 24. Consumers posits that "[t]his increase will enable the Company to manage any challenges or delays associated with bringing new resources online, changes in MISO's planning requirements that may impact the Company's PRMR, the migration to a seasonal capacity construct, and any degradation that might be applied to solar capacity accreditation." *Id*. Consumers then addresses claims regarding reliability and resource adequacy of WPSC, Energy Michigan, the BMPs, and Mackinac individually. *See*, Consumers' initial brief, pp. 24-56. As these positions are thoroughly outlined above, they will not be repeated here.

Consumers concludes that "the intent and focus of the Company's original PCA were maintained" by the settlement agreement "ensuring the Company's clean energy transition, as initially set forth in the Company's 2018 IRP." Consumers' initial brief, p. 56. Consumers argues that the PCA, as modified by the settlement agreement will "help lead a faster clean energy transformation by accelerating the Company's exit from coal-fired generation in 2025 while increasing reliability and providing resource adequacy for customers." *Id*. The company provides that "the Settlement Agreement will continue the Company's competitive procurement of clean energy resources by procuring approximately 8,000 MWs of solar resources by 2040 and will also accelerate the deployment of battery storage." *Id*., pp. 56-57. Finally, "like the Company's initially filed plan, the PCA, as modified in the Settlement Agreement, continues to save customers money–providing for customer savings of nearly $600 million." *Id*., p. 57.

Consumers asserts that the settlement agreement "meets the requirements of the Commission's rule for approving contested settlement agreements, Rule 431, and the requirements for approving an IRP under Section 6t." *Id*.

10. <u>The Biomass Merchant Plants</u>

The BMPs first summarize the contested settlement agreement before turning to the issue of the scope of the proceeding. The BMPs aver that their position is not beyond the scope of this IRP proceeding as their "objections in this proceeding are that the modified IRP fails specific statutory requirements of MCL 460.6t(8)" and that the "most reasonable and prudent means" under the statute requires the review of alternative plans which is what the BMPs offered in this case. BMPs' initial brief, p. 6, 8 (emphasis omitted). The BMPs reiterate their objections, which were overruled by the ALJ to the company's testimony, again claiming they did not have an opportunity to respond. *See*, *id*., pp. 9-10.[4]

The BMPs argue that the settlement agreement fails the resource adequacy and reliability requirements under the statute as there is a shortfall in ZRCs. Thus, the BMPs state that the settlement agreement should be modified because "[c]ontinuing to purchase capacity and energy from the BMPs through 2035 would, in fact, correct both that statutory defect and the Company's strategic goal." *Id*., p. 11. The BMPs further argue that the settlement agreement also fails to recognize the likelihood of the reduction of solar accreditation "down as low as 30% in the next

[4] The Commission notes that the BMPs made several references to appealing evidentiary rulings throughout its initial brief. *See*, BMPs' initial brief, pp. 9, 10, 36, 42-43. The Commission's rules set forth the standard for appealing rulings of presiding officers. *See*, Mich Admin Code, R 792.10433 (Rule 433). In part, Rule 433(3) states that "[a]n offer of proof shall be made in connection with an appeal of a ruling excluding evidence" and that "[i]f the ruling excluded written evidence or evidence that refers to documents or records, the offer of proof shall consist of a copy of the evidence, documents, or records." In addition, Rule 433(4) states that an application for appealing a ruling of a presiding officer "shall be supported by a clear and concise brief, pursuant to the provisions of R 792.10434, stating the basis for the appeal and showing that it complies with the provisions of this rule. The brief shall be supported by specific factual allegations as appropriate." The Commission finds that the BMPs have not met these minimum standards set forth under Rule 433. Therefore, the Commission denies any appeal of rulings made by the presiding officer in this proceeding as set forth in the BMPs' initial brief.

several years." *Id*., p. 12 (footnote omitted). The BMPs reiterate the testimony to aver that resource adequacy concerns are compounded by issues surrounding solar and battery storage and that the settlement agreement fails to address "the question of what energy is being stored, solar or fossil fuel generated energy. Solar energy can only be stored if that solar production exceeds load. If the load exceeds the solar generation, the energy being stored is from fossil fuel generation." *Id*., p. 15.

The BMPs reiterate their concern regarding Consumers' "use of an incorrect solar capacity factor" which it avers "is 20.6% greater than the average capacity factor of all solar generation facilities currently operating in Consumers' service territory." *Id*., pp. 4, 17. The BMPs state "[i]n contrast to the proposed solar capacity, the generation from the Biomass Plants is well known and MISO is not considering revisions to their ZRC accreditations." *Id*., p. 22.

Citing MCL 460.6t(8)(b), ED 2020-10, and the IRP filing requirements, the BMPs argue that "despite the fact that the Biomass Plants are located within Consumers' service territory," the settlement agreement disregards "the economic impact of the potential closure of those plants on the communities in which they are located." BMPs' initial brief, pp. 22-23. Therefore, the BMPs aver that the settlement agreement violates the statutory mandate because it "chooses to import energy into Michigan from other states" and "supports out-of-state construction and production rather than in-state construction, construction upgrades, construction maintenance and in-states generation." *Id*., p. 24.

The BMPs contend that the settlement agreement also does not meet the requirements in MCL 460.6t(8)(a)(v) because it fails to address potential future lack of capacity and that any early retiring plant could be designated as a system support resource (SSR), requiring it to remain in operation and that the "designation costs can run into significant millions of dollars." BMPs' initial brief, pp. 25-26. Similarly, under MCL 460.6t(8)(a)(vi), the BMPs aver that the settlement does not "appropriately balance the diversity of generation resources" which "impacts that commodity price risk" under MCL 460.6t(a)(v). BMPs' initial brief, p. 26. The BMPs reiterate the record testimony to support this contention arguing that "the first tranche of the One Time Solicitation will almost certainly result in Consumers acquiring natural gas capacity" which will likely include the CMS plants, "all of which are natural gas fired generation" and that this "concentrated amount of natural gas fired generation has commodity price risk . . . ." *Id*., pp. 27-28.

The BMPs restate the position that Consumers has inappropriately excluded generation from the biomass plants from the settlement agreement and that the company improperly relied on "the cost of new Biomass construction even though the Biomass Plants are existing construction, not new construction." *Id*., p. 30 (emphasis omitted). Reiterating record testimony, the BMPs aver that the settlement agreement violates the "statutory obligation under MCL 460.6t(1)(f)(iii) to include 'any supply-side and demand-side resources that reasonably could address any need for additional generation capacity . . . .'" BMPs' initial brief, p. 33. The BMPs further claim that the biomass plants are excluded from the one-time solicitation based upon the criteria set forth in the settlement agreement. *See*, *id*., pp. 35-38.

The BMPs contend that the settlement agreement violates ED 2020-10 and Michigan's Healthy Climate Plan. *Id*., p. 38. In support of this position, the BMPs state:

> The Settlement Agreement simply fails to consider the environmental benefits of the Biomass Plants as compared to the non-intermittent fossil fuel generation that will be acquired under the IRP as modified by the Settlement Agreement. It also fails to consider the unequaled ability of the Biomass Plants to help Consumers reach the goals of both Executive Directive 2020-10 and Michigan Healthy Climate Plan. The Biomass Plants' fuel composition is described in detail in Mr. Polich's testimony. The Biomass Plants are not only net-zero carbon generation, they have

> the further benefit of preventing the release of Methane from decomposing forest wood waste into the atmosphere.

BMPs' initial brief, p. 40 (footnote omitted). The BMPs further argue that the environmental benefits of biomass fueled generation include a much smaller land use than solar and that "[c]ontinuing to purchase 188 MW of energy from the existing Biomass Plants means that between 1,128 to 1,504 acres of land can be left undisturbed by an equivalent amount of solar projects." *Id.*, p. 42.

The BMPs restate that the ALJ erred in numerous evidentiary rulings including sustaining objections and limiting the time for cross-examination. *See*, *id.*, p. 43. In conclusion, the BMPs "object to the Settlement Agreement as presented and request that it be amended to include a provision pursuant to which Consumers will continue to purchase capacity and energy from the Biomass Plants after the end dates of their current contracts until 2035." *Id.*, p. 44.

11. Citizens Utility Board of Michigan

CUB argues that the settlement agreement improves upon Consumers' original PCA and is in compliance with Rule 431. CUB states that the settlement agreement improves the PCA as it improves the future analyses of marginal line losses and avoided transmission and distribution costs and that:

> [w]hile the Settlement Agreement does not require Consumers to reevaluate residential DR potential in this IRP . . . its commitment to collecting and reporting valuable marginal line loss data and including marginal line losses and avoided T&D costs in its evaluation of all distributed resources in future IRPs is a fair and reasonable compromise.

CUB's initial brief, p. 3. CUB also notes that the settlement agreement removes the 20% FIM Consumers was seeking in this proceeding. *Id.*

CUB notes that the parties signing the settlement agreement "represent a broad spectrum of the public interest, including the interests of residential ratepayers, commercial and industrial ratepayers, businesses, and environmental groups" demonstrating the public interest is adequately represented. *Id*., p. 4 (citing 10 Tr 4407-4408). CUB reemphasizes its testimony and avers that the substantial record demonstrates that the settlement agreement "and provides a fair and reasonable resolution of their respective concerns in this proceeding." *Id*., p. 5. Finally, CUB states that "the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition" to the contested settlement agreement, therefore satisfying all requirements of Rule 431. CUB's initial brief, p. 6.

12. <u>Wolverine Power Supply Cooperative</u>

WPSC argues that the settlement agreement fails to meet the requirements of Rule 431. WPSC avers that the settlement agreement is not in the public interest as it will allow the retirement of Campbell 3 in 2025 which "will further stress Michigan's already-strained grid system" and that this "fails to represent a fair and reasonable resolution to the proceeding." WPSC's initial brief, pp. 2-3. Pointing to the record and the PFD, WPSC states that a 2025 retirement of Campbell 3 is not well-supported. WPSC argues that approval of the settlement agreement "requires a set of parallel, perfect, and, therefore, unlikely outcomes" and lists those outcomes as follows:

> (1) despite MISO's projections, Zone 7 realizes sufficient resources to serve Michigan, (2) Consumers realizes declining load growth, despite economic projections and announced load growth; (3) Consumers' one-time solicitation is fully successful in acquiring 700 incremental Zonal Resource Credits ("ZRC") that are installed and delivered in less than three years, and (4) Consumers realizes the outcome of its modeling—a complete disconnection from the rest of Michigan's grid.

Id., p. 3 (footnote omitted).

WPSC states that:

> [w]hen reviewing more current data from Consumers' own capacity demonstration filing in Case No. U-21099, which shows a 271 ZRC deficit in 2022 or 425 ZRC

> lower than the PCA even with the same supply mix, . . . unless it acquires a material portion of the solicitation, Consumers will be capacity negative in 2025, even with the Covert purchase and keeping Karn Unit 3 and 4 online through 2030. (Testimony of Thomas King, 10 Tr 4303; Rebuttal Testimony of Thomas King, 10 Tr 4311-4312.)

Id., p. 4 (emphasis in original). WPSC further argues that the settlement agreement's effort of allowing a one-time solicitation of 700 ZRCs to combat reliability concerns from the early retirement "does not ensure Consumers customers are shielded from resource adequacy shortfalls in Zone 7 – the projects must actually be built and the 700 ZRCs of dispatchable and intermittent resources likely cannot be built in time." *Id*., p. 4. Continuing, WPSC points out that "the proposed solicitation will not create any incremental (i.e., new) Zone 7 capacity" and is merely another path to utilize the CMS plants as originally proposed in the PCA. *Id*. Reiterating its testimony, if Campbell 3 is replaced with existing Zone 7 capacity there will be a net negative capacity position in the zone which, WPSC avers "places Michigan on a path toward load shed (e.g., blackouts) that is likely to harm Michigan residents." *Id*., p. 6 (citing 10 Tr 4312).

WPSC reiterates its testimony that, despite Consumers' assumption, the market reality is that there is a declining PRMR between 2022 and 2025, and that it "it conflicts with MISO's statements of increasing load forecasts." *Id*., p. 7 (citing 10 Tr 4305 and Exhibit WPSC-6). WPSC further points to developmental projects which will result in incremental load increases and argues that Consumers' estimates of increases in DR are not supported by any evidence indicating that such is possible. WPSC further states that the company's assurances that there is time to address the shortfall in the future is insufficient and that "it is unreasonable for Consumers to utilize an unsupported, lower reserve margin for the future." *Id*., p. 8.

WPSC further argues that, while the first 500 ZRCs for the proposed solicitation are likely to come from existing Zone 7 resources, "the second tranche of 200 ZRCs are likely to be procured from intermittent resources" and that "[t]he record is devoid of evidence regarding where the needed resources would come from." *Id.*, p. 9 (citing 10 Tr 4312). WPSC states that the denial that the solicitation is speculative "demonstrates a fundamental misunderstanding of the current renewables landscape" and even as "more solar resources are added to the grid, less benefit is realized and the solar capacity accreditation declines to match performance." *Id*. (citing Exhibit WPSC-8). WPSC reiterates its position that the 500 MW is unreasonable noting that:

> [e]ven if the proposed 500 MW of projects were able to procure materials and Consumers is capable of acquiring and utilizing the nearly 3,500 necessary open acres of Michigan land, the projects would also need to achieve the local government approvals, complete MISO's byzantine generation queue process, and complete transmission improvements necessary to facilitate construction and interconnection—all within the limited time available.

Id., p. 10.

In addition, WPSC avers that the settlement agreement inappropriately requires Consumers to be treated as an island rather than an integrated and interconnected participant in the Michigan electric grid. WPSC argues that "[g]iven the likely capacity shortfall in Zone 7, the [settlement agreement's] failure to address transmission deficiencies will exacerbate the problems created by hastily retiring generation resources. If one of the few existing ties fail or export capability from other areas is reduced, the only other option will be load shed." *Id*., p. 11 (footnote omitted).

WPSC concludes that, under Rule 431, the Commission must deny the settlement agreement as it "is not supported by *any* evidence within the record, and certainly is not supported by *substantial* evidence on the record" but rather that the record demonstrates additional modeling and analysis is needed to support an early retirement of Campbell Unit 3. *Id*., p. 12 (emphasis in original). WPSC further states that "[r]ushing the retirement of Campbell Unit 3 may allow the Commission to continue forward with its admirable goal of reducing Michigan's carbon emissions, but it will come at the risk of electric reliability and related health and safety of

Michiganders." *Id*. WPSC avers that the settlement agreement does not reflect the most reasonable and prudent path and that the Commission should "require Consumers to keep Campbell Unit 3 in operation, at least until Consumers can present hard data that verifies that Campbell Unit 3 can be retired without jeopardizing reliability and, as the PFD notes, Consumers has not modeled or analyzed these issues sufficiently." *Id*., p. 13.

13. Urban Core Collective

UCC filed a statement in support of the settlement agreement in lieu of an initial brief to reaffirm its initial support as a signatory to the settlement agreement. *See*, Case No. U-21090, filing #U-21090-0857.

D. Reply Briefs

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

In reply to Energy Michigan, MNS argues that Energy Michigan errs in positing that the considerations under MCL 460.6t(8) somehow trump the Rule 431 criteria. MNS' reply brief, pp. 2-3. MNS notes that the Michigan Administrative Procedures Act (APA) also addresses settlements and provides that contested cases may end in settlement when agreed to by the parties in MCL 24.278(2). *Id*., p. 3. MNS contends that Rule 431 implements this statutory requirement. While agreeing with Energy Michigan that it is important to harmonize the IRP statute and Rule 431, MNS contends that Energy Michigan's reading of MCL 460.6t(8) would make applying the requirements of Rule 431 an "empty exercise." *Id*., p. 4. MNS further contends that Energy Michigan's argument conflicts with the Commission's approval of the contested settlement in Case No. U-20165. *Id*. (citing June 7, 2019 order in Case No. U-20165, p. 76 (June 7 order); *see also*, June 7 order, p. 91).

MNS states that it addressed Energy Michigan's resource adequacy and pricing arguments in its initial brief, and notes that Energy Michigan was included in all settlement discussions, asserting that Energy Michigan was included in multiple emails regarding the settlement conference which took place in February 2022. MNS' reply brief, p. 5.

In reply to WPSC, MNS again argues (as it did in its initial brief) that, contrary to WPSC's assertions, the settlement agreement will actually improve resource adequacy in Zone 7. MNS again points to the 1,114 ZRCs from the Covert gas plant, 71 ZRCs of new battery storage, 250 ZRCs of new solar generation, and 94 ZRCs of new demand side resources, and states that "[e]ven with the retirement of the Campbell coal units, these resource additions will result in an overall net increase in Zone 7 resources." *Id.*, p. 7 (citing 9 Tr 5-6, 10 Tr 4350, and Settlement Agreement, Sections 1-3); *see also*, 10 Tr 4405-4406. MNS further argues that WPSC's repeated citations to the PFD for support are inapposite since the PFD evaluated the original PCA, which presented actual resource adequacy concerns. MNS' reply brief, pp. 8-9.

MNS contends that the Commission should not consider the websites and news stories cited by WPSC regarding the PRMR because they are not part of the record, and, in any case, Mr. Jester, Mr. Proudfoot, and Mr. Clark rebutted these concerns. MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407) (citing 10 Tr 4358-4359 and 4227-4228). MNS notes that Mr. Proudfoot testified that:

> The reserve margin used by the Company in its capacity demonstration for 2025 comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report. It is also worth noting that assuming a constant reserve margin of 8.7% instead of 7.4% would represent about 100 MW of additional obligation to the Company. The differences between Karn Units 3 & 4 and the CMS capacity is still likely enough to cover this difference, even without counting any additional capacity from the one-time solicitation.

MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407). MNS asserts that WPSC's claims about Consumers being capacity negative are simply untrue as shown by the list of ZRCs described above, and states that "Consumers would still have a surplus even if both tranches of the one-time solicitation fail entirely: in that extremely unlikely scenario, Consumers would still have a 514 ZRC surplus in 2025/26." MNS' reply brief, p. 11 (citing 10 Tr 4354). Finally, on this issue, MNS avers that Mr. Jester showed that Mr. King's calculations were incorrect because Mr. King assumed that Karn Units 3 and 4 would be operating in the 2025/2026 planning year. MNS' reply brief, p. 12 (citing 10 Tr 4355). MNS notes that WPSC fails to cite to any record evidence showing that the retirement of Campbell Unit 3 in 2025 is unsupported. MNS' reply brief, p. 12.

In reply to the BMPs, MNS argues that their claims regarding a lower ELCC are exaggerated and inaccurate, and states that the BMPs mischaracterized Mr. Clark's testimony where he indicated that the ELCC "could" drop. MNS' reply brief, p. 15 (citing 5 Tr 1123) (emphasis omitted). Additionally, MNS notes that several witnesses refuted this argument, including Mr. Clark himself when he testified that the ELCC has been stable for six years and no changes are pending. MNS' reply brief, pp. 15-16 (citing 10 Tr 4226-4227, 4236). MNS observes that Mr. Blumenstock testified that even applying the BMPs' 30% ELCC figure, there would be no shortfall for eight years. MNS' reply brief, p. 16 (citing 10 Tr 4142-4143). Additionally, MNS notes, Mr. Jester showed that the BMPs' figure comes from an exploratory modeling exercise. MNS' reply brief, p. 16 (citing 10 Tr 4365-4366).

Finally, MNS objects to the BMPs' appeal of certain evidentiary rulings made by the ALJ, noting that the BMPs fail to cite to any legal authority in support of their appeal. MNS argues that a party may not "simply announce a position on appeal and leave it to the reviewing body to search for authority to support the party's position." MNS' reply brief, p. 18 (citing *Wilson v*

Taylor, 457 Mich 232, 243; 577 NW2d 100 (1998)). MNS contends that the BMPs' counsel misrepresented how long his cross-examination of Mr. Blumenstock would last, and then offered questions on irrelevant subjects. MNS' reply brief, p. 18 (citing 10 Tr 4193, 4211). MNS contends that, under MCL 24.280(1)(d), the presiding officer is empowered to regulate the course of the proceedings. MNS avers that the ALJ's rulings were reasonable and well within her authority and should be affirmed. MNS' reply brief, pp. 18-19.

In reply to Mackinac, MNS urges the Commission to give no weight to Mackinac's brief. As an initial matter, MNS alleges that Mackinac did not comply with the requirements of Rule 431(3) when it filed its objection, because it failed to state its objections with particularity or specify how it would be adversely affected by the settlement agreement. Additionally, MNS argues, Mackinac's initial brief is mostly cut-and-pasted from its exceptions, and the exceptions were focused on the PFD and the original PCA – a different factual scenario. MNS notes that Mackinac's initial brief is filled with unsupported assertions and relies heavily on news stories and website links that are not part of the record, contrary to the requirements of the APA. MNS' reply brief, pp. 20-21 (citing MCL 24.276 and 24.285). Moreover, MNS posits, DR and CVR programs are not designed to cut off customers from electricity. MNS describes Mackinac as "ill-informed." MNS' reply brief, pp. 21-22.

2. <u>The Commission Staff</u>

In reply, the Staff states that MCL 460.6t(8) provides seven factors for the Commission to balance when determining if the statutory requirements are satisfied. The Staff states that the settlement agreement is a compromise made by parties with a wide variety of interests and is reasonable and prudent. The Staff also contends that "the settlement agreement also balances the reliability needs of MISO Zone 7 with Consumers' ability to provide energy and capacity to its customers." Staff's reply brief, p. 2 (citing Staff's initial brief, pp. 3-5).

Regarding resource adequacy concerns, the Staff replies that the PCA, as modified by the settlement agreement, is reasonable and prudent and balances the reliability needs of Zone 7. *See*, Staff's reply brief, p. 3. Continuing, the Staff avers that "[g]iven the capacity from Karn Units 3 and 4, additional solar resources, and the up to 700 MW one-time solicitation set forth in the settlement agreement, Staff . . . does not believe Consumers is likely to be short on capacity in 2025" and that "this capacity is more than sufficient to make up the capacity assumed for the CMS [plants] contemplated in Consumers' original IRP and may even be sufficient to meet Consumers' previous planning reserve margin of 8.7% that [WPSC] referenced in direct testimony." *Id.*, pp. 3 4 (citing 10 Tr 4306, 4406-4407).

In response to the BMPs' testimony regarding a deficiency in 2035, the Staff replies:

> that the IRP statute requires 5-, 10-, and 15-year projections of the utility's load obligation and plan, but Commission cost approval for investments or resources used to meet energy and capacity need is only presumed reasonable and prudent for those actions commenced within three years of Commission approval of the IRP. MCL 460.6t(3), (11).

Staff's reply brief, p. 4. Therefore, the Staff avers that there is a likelihood that changes will occur between the approval of the IRP and the long-term projections as further reinforced by the requirement in MCL 460.6t(20) for regulated utilities make an IRP filing at least every 5 years. *Id*.

Finally, the Staff avers that Mackinac's "initial brief contains many footnotes citing to material that was not offered into evidence or addressed in testimony" and that Mackinac "did not file testimony in either phase of this proceeding and filed a one-page objection to the settlement agreement." *Id.*, p. 6. Therefore, the Staff requests that the Commission disregard the portions of

Mackinac's briefing supporting its objections to the settlement agreement not supported on the record.

3. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

In reply to the BMPs, the CEOs point out that the BMPs' request to modify the settlement agreement is a form of relief that is unavailable because the settlement agreement is not severable, thus modification would result in rejection of the entire agreement. CEOs' reply brief, p. 1, n. 1. The CEOs further aver that the BMPs' contracts should not be extended in any case due to the non-carbon pollution associated with their operations as well as the documented environmental justice concerns. CEOs' reply brief, p. 2. The CEOs note that one of the directives issued by Governor Whitmer pursuant to ED 2020-10 requires the Michigan Department of Environment, Great Lakes, and Energy to include considerations of environmental justice and public health when issuing advisory opinions in IRP proceedings. *Id.*, pp. 2-3. The CEOs submit that they provided extensive evidence on the record showing the non-carbon air pollution emissions and environmental justice concerns associated with the BMPs, stating that:

> [s]ome of these plants co-fire tire-derived fuels, and most of them have higher emission rates of $PM_{2.5}$ and NOx than even Consumers' coal plants. (Krieger, 7 TR 2383). Moreover, eight of nine plants are located in areas considered more low-income than the state median. (Krieger, 7 TR 2383). The 38,000 people living near the Genesee plant rank in the 89th percentile for low-income populations, 86th percentile for populations of color, and 83rd percentile on the EJ [Environmental Justice] Index. (Krieger, 7 TR 2384). "[B]iomass power plants are likely to have higher air pollutant emissions rates per unit energy produced."

CEOs' reply brief, p. 3 (quoting 7 Tr 2397) (emphasis omitted). The CEOs note that Dr. Bilsback concluded that the emissions rates of biomass plants are comparable to fossil-fuel fired plants. CEOs' reply brief, p. 4 (citing 7 Tr 2418). The CEOs contend that simply because a fuel source may be renewable does not mean that it will not have health impacts; and they note that the BMPs did not rebut this testimony. CEOs' reply brief, p. 4.

The CEOs also regard the BMPs' argument that the settlement agreement is a ploy to allow for the construction of a natural gas plant as far-fetched. The CEOs point out that the settlement agreement (Section 6.b.ii.) limits the second tranche to "intermittent resources and dispatchable, nonintermittent clean capacity resources (including batter storage resources)," which could not be reasonably interpreted to include natural gas. *Id*. (quoting Settlement Agreement, p. 6). The CEOs further note that they would not be signatories to a settlement agreement that contemplates the construction of a new gas plant. CEOs' reply brief, p. 5 (citing 7 Tr 2354 and 10 Tr 4347). The CEOs contend that the land use concerns raised by the BMPs do not appear to relate to ED 2020-10. CEOs' reply brief, pp. 5-6.

The CEOs further argue that WPSC and the BMPs attempt to use scare tactics based on market information. The CEOs assert that Consumers used an appropriate capacity factor in its modeling, stating that, in reference to the BMPs' evidence, "[a]s Company witness Battaglia explained on rebuttal, the information shown in BMP-6 is presented in DC, rather than AC, and therefore does not present a comparable capacity factor to that used by the Company in modeling. (Battaglia Direct, 5 TR 1217:4-12)." CEOs' reply brief, p. 7. The CEOs also note that the BMPs focused on the wrong witness with respect to their ELCC arguments, as the solar capacity factor was covered by Mr. Kapala and not Mr. Battaglia (and this mistake was noted by the ALJ as well). *Id*., p. 8 (citing 6 Tr 1296-1297; 7 Tr 1822). The CEOs further assert that WPSC's theory that Consumers will be unable to acquire 250 ZRCs of solar by 2025 was refuted by Mr. Lucas. CEOs' reply brief, p. 9 (citing 10 Tr 4382-4384). They also cite to the testimony of Mr. Clark and Mr. Jester refuting the notion that the ELCC poses an unreasonable risk to the settlement agreement. CEOs' reply brief, p. 9 (citing 10 Tr 4236, 4367-4368). Finally, the CEOs point to Mr. Blumenstock's testimony that Karn Units 3 and 4 are unlikely to become system support resources. CEOs' reply brief, p. 10 (citing 10 Tr 4152).

The CEOs assert that Mackinac's arguments are improper and redundant. CEOs' reply brief, p. 10.

4. Consumers Energy Company

Consumers initially provides an overview of the arguments of the signatories to the settlement agreement reiterating its position that the settlement agreement is in the public interest, was the result of good-faith negotiation, and that the outcome is the most reasonable and prudent means of meeting the company's energy and capacity needs. Consumers' reply brief, pp. 3-5.

Consumers argues that issues raised by WPSC with regard to reliability and resource adequacy concerns have been addressed by the company's initial brief. Specifically, Consumers states that "[WPSC]'s claim . . . that the one-time solicitation will likely not create new [MISO LRZ] 7 capacity, is of no consequence" for the reasons set forth in its initial brief. *Id*., p. 6. Consumers argues that "[t]he purpose of the one-time solicitation is to help replace the capacity and energy lost when Consumers Energy retires [Campbell] Units 1, 2, and 3 in 2025." *Id*. Consumers repeats that "[t]he Company is not required to provide capacity for [WPSC] or any other [LSEs] in LRZ 7." *Id*. Consumers states that WPSC's arguments that the settlement agreement will reduce reliability in LRZ 7 are "without merit" as outlined in its initial brief and WPSC has "failed to provide information showing any purported negative impact on [WPSC] . . . ." *Id*., p. 7. Consumers reiterates that the settlement agreement will "bring at least 2,084 ZRCs into MISO's LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ 7 of nearly 700 ZRCs." *Id*. (footnote omitted). In response to WPSC's claims that the company's

PRMR will increase rather than decrease, Consumers argues that it has “fully supported its projected PRMR decrease” in its initial brief. *Id*. Consumers argues that WPSC’s claims that the one-time solicitation is “speculative and not supported by the record” are “meritless” and “Consumers Energy projects sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation, and many possible sources could fill the 700 ZRCs once the bidding commences.” *Id*., p. 8 (quoting WPSC’s initial brief, p. 9).

Consumers addresses WPSC’s claim that the settlement agreement would “treat Consumers Energy as an ‘island,’ and that a capacity shortfall would affect [WPSC] and other LSEs in the state.” Consumers reply brief, p. 8 (quoting WPSC’s initial brief, p. 10). Consumers asserts that:

> Michigan law contemplates that each electric provider plan to serve its own projected loads; it does not require electric providers to serve other electric providers’ loads, unless a utility is required to provide backup capacity under the state reliability mechanism in situations in which alternative electric suppliers fail to demonstrate compliance with their own four-year forward capacity obligations.

Consumers reply brief, p. 8 (citing MCL 460.6w). Consumers discredits WPSC’s claims that the record does not support the settlement agreement. *See*, Consumers’ reply brief, p. 9.

Turning to Energy Michigan’s arguments, Consumers first agrees with Energy Michigan’s contention that “the Commission Rule 431 standards for approving a contested settlement must harmonize with Section 6t(8) [of Act 341], and cannot overrule it or provide a ‘different and weaker approval standard.’” Consumers reply brief, p. 9 (quoting Energy Michigan’s initial brief, p. 2). Consumers posits that the settlement agreement “meets all criteria for approval contained in MCL 460.6t(8) and Commission Rule 431.” Consumers reply brief, p. 9.

Consumers addresses Energy Michigan’s assertion that company testimony stating “that ‘Consumers Energy is not responsible to ensure the reliability of Zone 7 beyond its own capacity obligations' indicates that the Company has changed its position, given that Mr. Clark described the IRP as the best plan 'for Michigan.'" *Id*., p. 10 (quoting Energy Michigan's initial brief, p. 3). Consumers asserts that it has not changed its position. Specifically, Consumers states that:

> The IRP, as set forth in the Settlement Agreement, remains the best plan for Michigan, as it will meet its customers' energy needs, will satisfy the Company's PRMR obligations within LRZ 7, and further the Company's goal to be carbon neutral by 2040 and retire all coal generation by 2025. Having the best plan for Michigan does not mean that Consumers Energy must single-handedly supply sufficient capacity for every other utility's expected load in Michigan. It means having a plan that meets all of Consumers Energy's customers' capacity needs in a manner that avoids unnecessary environmental impacts that affect the whole state and benefits the state's economy positively. An IRP that accomplishes these objectives is best for Michigan.

Consumers' reply brief, p. 10.

Consumers replies to Energy Michigan's claim that the one-time solicitation might ultimately lead to PPAs with CMS Enterprises. *Id*. Consumers responds that "[t]he Company has not yet issued the solicitation, thus Energy Michigan is merely speculating which resources will win." *Id*. Consumers avers that "even in the scenario that Energy Michigan envisions, no adverse impact on resource reliability or adequacy would result." *Id*.

Consumers refutes Energy Michigan's claim "that it was never invited to a settlement meeting, that its comments on the draft settlement agreement were neither welcomed nor considered," and that Energy Michigan was explicitly told that no changes it sent the company would be considered. *Id*., p. 11. Consumers posits that "[a] settlement meeting was held with all parties on February 16, 2022, and Energy Michigan's counsel participated in that meeting. Energy Michigan did not engage in settlement discussions after that meeting, even though such engagement was encouraged by the Company." *Id*. Further, Consumers states that "[b]eyond the February 16, 2022 settlement meeting, Energy Michigan was also engaged by the Company regarding settlement on numerous occasions including March 28,2022, April 15, 2022, and April 19, 2022." *Id*., pp. 11-12.

Consumers avers that "Energy Michigan's assertions regarding the settlement process is irrelevant and beyond the scope of this case" as "other potential settlement outcomes are not within the scope of issues to be decided by the Commission in a contested settlement proceeding . . . ." *Id*., p. 12 (citing June 7, 2019 order in Case No. U-20165). Consumers also posits that the "[Commission]'s Rules of Practice and Procedure make clear that reaching a total consensus is not required for settlement." Consumers' reply brief, p. 12. Consumers adds that "Rule 431 makes clear that a settlement may be 'proposed by some of the parties." *Id*. (quoting Mich Admin Code, R 792.10431(3)). Further, Consumers quotes Rule 431 as stating that "'provisions of these rules shall not be construed in any way to prohibit settlements.'" Consumers' reply brief, pp. 12-13 (quoting Mich Admin Code, R 792.10431(3)).

Turning to the claims of the BMPs, Consumers argues that "even though the BMPs are claiming that the Settlement Agreement is flawed, they are at the same time conceding that all of those purported flaws melt away if the BMPs just get what they want—to amend the Settlement Agreement to force Consumers Energy to extend PPAs with its member plants." Consumers' reply brief, p. 14. Consumers posits that "[t]he BMPs' position illuminates the fact that there are not really flaws in the Settlement Agreement, as the BMPs' [sic] claim, and that the BMPs' position merely seeks to promote their own economic interests." *Id*. Further, Consumers avers that the BMPs have not established that their member plants are an economic and reasonable option for Consumers' customers following the expiration of the current PPAs for those plants. *Id*. Consumers further reiterates its positions from brief that the company does not have an obligation to enter into new contracts with the BMPs, that the BMPs were considered in the development of the IRP, and that the BMPs have not produced evidence that they represent a viable economic option. *Id*. Consumers asserts that the BMPs' alterative proposal under Section 6t(6) of Act 341 is not supported because "the BMPs have failed to address and meet the filing requirements for an alternative proposal, as provided in the Certificate of Necessity and Integrated Resource Plan Alternative Filing Requirements." Consumers' reply brief, p. 15 (citing December 20, 2017 order in Case No. U-18461, Exhibit B). Consumers opines that the BMPs requested relief should be rejected because "[t]he BMPs have not established that their member plants will be an economic and reasonable resource option for customers and therefore, there is no basis to support the BMPs' request to force the Company to extend PPAs with those plants." Consumers' reply brief, p. 16.

In response to the BMPs' claims that the settlement agreement fails to meet the resource adequacy and reliability requirements of Sections 6t(8)(a)(i) and (iv) of Act 341, Consumers asserts that "[t]he Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and Local Clearing Requirement . . . ." Consumers' reply brief, p. 17. Consumers argues that the settlement agreement has "maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-response resources, expansion of renewable resources, and deployment of battery storage resources." *Id*. (citing 10 Tr 4121). Consumers also reiterated that the settlement agreement provides mechanisms to procure additional capacity if needed. Consumers' reply brief, p. 17. Consumers posits that the settlement agreement provides for "electric reliability assurance" and that the "flexibility of phased-in modular resources provided for in the Settlement Agreement PCA also provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary." *Id*., p. 18.

Consumers contests the BMPs' claim that the company used an incorrect capacity accreditation for its solar resources. Consumers restates that the company's PCA "uses the current MISO solar capacity accreditation practices which provide solar with a 50% capacity accreditation." *Id*. (citing 10 Tr 4142). Consumers reiterates its arguments that "that MISO solar capacity accreditation value is also only relevant to newly installed solar and not solar that is in actual operation. Capacity accreditation at the Company's existing solar facilities has been as high as 65%, based on actual performance." Consumers' reply brief, p. 19 (citing 10 Tr 4142). Consumers argues that the company has supported its modeled capacity factor for solar with projections from third-party resources. Consumers' reply brief, p. 19. Thus, Consumers opines that the BMPs' resource adequacy and reliability arguments should be rejected. *Id*.

Responding to the BMPs' claims that the settlement agreement fails to meet the requirements of Section 6t(8)(b) of Act 341 and Governor Gretchen Whitmer's MI Healthy Climate Plan pursuant to ED 2020-10, Consumers argues that "the record establishes that the Settlement Agreement is aligned with that plan, and will help promote its success." Consumers' reply brief, p. 20. Consumers adds that to the extent the BMPs are arguing that additional imports from the market violate ED 2020-10, the PCA, as modified by the settlement agreement, "reduced the need for market purchases" and "continues to maintain that reduced market dependence through the purchase of the Covert Plant and one-time solicitation . . . ." *Id*.

Addressing the BMPs' assertion that Karn Units 3 and 4 could be designated as an SSR, Consumers reiterates that "an SSR designation would result from an electric transmission system deficiency that must be mitigated and not due to a capacity or energy shortfall." *Id*., p. 21. Reiterating its earlier testimony, Consumers argues that the risk of an SSR designation is unsupported. *Id*., pp. 20-21.

In response to the BMPs' assertion that the settlement agreement fails to appropriately balance the diversity of generation resources with the impacts on commodity price risk, Consumers asserts that the settlement agreement provides for a diverse portfolio of resources as outlined in its testimony. *Id*., p. 21. Consumers posits that "[t]his resource mix represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks." *Id*. Further, Consumers asserts that this approach will "provide further opportunities for the utilization of diverse supply resources and protects against high customer rates." *Id*.

Consumers reiterates its arguments, outlined above, regarding the scope of the contested settlement agreement in response to the BMPs. *See, id*., pp. 23-26. Consumers reasserts that the BMPs attempt to propose another version of the settlement agreement is "improper and not supported." Consumers' reply brief, p. 25. On pages 26 through 33 of its reply brief, Consumers addresses the BMPs' appeal of the ALJ's rulings.

Consumers asserts that Mackinac's objections to the settlement failed to comport with the Commission's procedural rules and should thus be disregarded. *Id*., pp. 32-33.

Consumers requests the Commission approve the settlement agreement in its entirety without any modifications or conditions. *Id*., p. 33.

5. <u>Wolverine Power Supply Cooperative</u>

WPSC argues that the settlement agreement "has neither the facts nor the law on its side and the Commission must reject it." WPSC's reply brief, p. 1. WPSC contends that the Staff has reversed its stance on the importance of resource adequacy as the Staff now contends that the settlement agreement "should be approved because Zonal resource adequacy is not Consumers' problem to solve." WPSC's reply brief, p. 3 (citing Staff's initial brief, p. 5). WPSC avers that while it is not the sole responsibility of Consumers to "ensure resource adequacy for the Zone, a significant component of the IRP framework is to ensure that a utility retiring resources does not do so in a manner that adversely impacts the Zone, which Consumers does here" and that "although Consumers may not be required to address a shortfall caused by others, it certainly must be required to address a shortfall it is creating." *Id*. (emphasis omitted).

WPSC again avers that the settlement agreement is not supported by substantial evidence and that the company has not disputed the negative ZRC values for 2022-2023 and 2025-2026. *See*, *id*., p. 4. WPSC reiterates concerns regarding the ELCC for solar assets, arguing that the 50% is not an accurate benchmark as "[i]t simply does not reflect reality, even if some are willing to pretend that it does." *Id*. WPSC further states that it has "identified actual impediments to Consumers' contemplated solar development and Consumers offered no explanation as to how it will overcome these hurdles, except to say there is time to address in future IRPs. [WPSC] identified the issues; Consumers identified no solutions." *Id*., p. 5.

Finally, WPSC argues that the Staff's briefing lacks confidence "[m]uch like Consumers' failure to explain its solution to the hurdles related to solar development, Staff appears to be counting on speculative 'other resources' that are not identified in brief or the record." *Id*. Therefore, WPSC avers that the settlement agreement is speculative and should be denied under Rule 431(5).

6. <u>The Biomass Merchant Plants</u>

In reply to Consumers, the BMPs reference their initial brief to respond to the claim that the BMPs' "requested relief is beyond the scope of these proceedings" averring that "[i]t is not." BMPs' reply brief, p. 2. The BMPs reiterate that while "PURPA may no longer require

Consumers to purchase generation from the Biomass Plants [that] does not mean that such purchases are not reasonable and prudent as a matter of state law" and that Consumers has done everything possible "to exclude the Biomass Plants from the IRP, regardless of whether or not including them would be reasonable and prudent." *Id*. (citing to BMPs' initial brief, p. 29-38). Reiterating the testimony and briefing, the BMPs state that the company never requested cost information from the BMPs and failed to explain why the cost of new construction was utilized for biomass generation. *See*, BMPs' reply brief, pp. 2-4.

Responding to Consumers' contention that the BMPs would be eligible to bid into the first tranche of the one-time solicitation, the BMPs aver that:

> [w]hile the Biomass Plants can be dispatched within their operational limits, they cannot be dispatched within one hour if they are not running. That fact, in addition to the fact that all of the Biomass Plants' current contracts extend into the 2025 to 2030 time period will exclude them from bidding in that solicitation.

Id., p. 4 (referencing Consumers' initial brief, p. 45). The BMPs again reference objections and excluded evidence which they aver were inappropriately ruled upon by the ALJ. The BMPs aver that Consumers failed to discuss "whether [Consumers] is likely to sign power purchase agreements with [the CMS plants] as a result of the first tranche of the One Time Solicitation, which is probable." *Id*., pp. 5-6. Further, the BMPs restate record testimony to aver that Consumers has still failed to rebut the BMPs' testimony regarding the overstated solar capacity factor the company has utilized, and the risk associated with proposed solar additions. *See*, *id*., pp. 6-10. The BMPs argue that Consumers' dismissal of the risks relating to the solar additions, and "its refusal to add the 188 MW of baseload, net zero carbon, renewable generation from the Biomass Plants to its IRP" are invalid and raise "serious questions as to whether the Biomass Plants are being excluded from the IRP for some other undisclosed commercial reason." *Id*., pp. 10-11.

V. Discussion

The Commission finds that the contested settlement agreement at issue in this case should be approved.

As stated above, Commission approval of a contested settlement agreement is appropriate where the Commission determines the following requirements have been met: (1) that the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, (3) the settlement agreement is in the public interest, (4) the settlement agreement represents a fair and reasonable resolution of the proceeding, and (5) the settlement agreement is supported by substantial evidence on the record as a whole. Mich Admin Code, R 792.10431.

The Commission finds that all the requirements of Rule 431 have been met. The Commission has provided a reasonable opportunity to those parties that objected to the settlement agreement to present evidence and argument in opposition to the settlement agreement. The parties were given the opportunity to submit direct and rebuttal testimony, file initial and reply briefs, and appear at an evidentiary hearing regarding the contested settlement agreement before a presiding officer. As the parties to this case observed, the principal record in this case consists of 4,094 pages of transcript and over 500 exhibits admitted into evidence. The record on the contested settlement alone consists of 315 additional pages of transcript and 22 additional exhibits admitted into evidence.

With respect to the second criterion, the record shows that the signatories to the settlement agreement represent a broad cross-section of interests, including residential customers, commercial and industrial customers, businesses in Michigan’s advanced energy sector, environmental groups, a transmission company, and third-party developers. *See*, 10 Tr 4407-4408. The Commission also notes that the Court of Appeals has affirmed the Commission's determination that the public interest is adequately represented by the Staff when the Staff is party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

Rule 431(5)(c) requires the Commission to make a three-part finding that: (1) the settlement agreement is in the public interest, (2) represents a fair and reasonable resolution of the proceeding, and (3) is supported by substantial evidence on the record as a whole.

The Commission finds that the settlement agreement is in the public interest. The Commission finds persuasive the testimony by Consumers and others that the settlement agreement was the result of good-faith negotiation that resulted in significant compromises for all involved. The negotiation of the parties is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. Signatory parties to this case highlighted the following provisions as compromises reached by settlement that are in the public interest, represent a fair and reasonable resolution of the proceeding, and are supported by substantial evidence on the record as a whole:

- The agreement that Consumers retire Campbell Units 1, 2, and 3 in 2025, which will result in savings to ratepayers, reduce the production of environmental pollutants, such as SO_2, NO_x, and particulate matter, and advance Michigan's clean energy goals as outlined in the MI Healthy Climate Plan as well as provide additional public health benefits;

- The agreement that Consumers will purchase the Covert plant in 2023, which will add 1,114 ZRCs to MISO Zone 7 to support reliability for Consumers as well as overall resource adequacy of the Zone;
- The agreement to conduct a one-time solicitation for 200 ZRCs of capacity and associated energy and RECs, which will provide additional clean capacity resources for Consumers' portfolio;
- The agreement that Consumers will deploy the battery program outlined in the rebuttal testimony in the principal case which will formalize an important component of a cleaner energy grid while enhancing reliability and resource adequacy;
- The agreement to seek recovery of the unrecovered book value and decommissioning costs of retiring coal units through regulatory asset treatment, rather than continued recovery through traditional ratemaking, which provides the potential for customer savings;
- The agreement that Consumers will donate $5 million dollars in shareholder funds to support bill assistance for lower-income customers along with continued annual donations;
- The agreement that Consumers will provide beneficial modeling in its next IRP, including total emissions, annual particulate matter health impacts, an environmental justice screening tool, projected low-income energy efficiency participation levels, publicly available rooftop solar adoption rates, and transmission import analysis; and
- The agreement that Consumers will take steps to engage and gather input from the public prior to the filing of its next IRP with the Commission, which will ensure that additional information and perspectives are available to inform both the company's assessment of its future resource options as well as Commission and stakeholder review of its proposals.

Energy Michigan, WPSC, the BMPs, and Mackinac disagree with the conclusion that the settlement is in the public interest and represents a reasonable resolution to the proceeding. The objecting parties' concerns involve the resource adequacy, reliability, and competitive pricing in MISO Zone 7. Specifically, the objecting parties argue that: (1) the settlement agreement does not meet the resource adequacy needs of MISO Zone 7 and (2) the one-time competitive solicitation will not adequately replace the capacity from retiring coal-fired generation. Each of these concerns are addressed in turn.

A. The Resource Adequacy of Zone 7

The parties objecting to the settlement agreement claim that the settlement agreement does not address the need for incremental capacity replacements in MISO Zone 7 following the retirement of Campbell Units 1, 2, and 3 to meet the resource adequacy requirements of the zone. As such, the objecting parties conclude that Consumers' PCA fails to meet the resource adequacy requirements of Section 6t(8)(a)(i) and (iv) that the Commission must balance "[r]esource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement" and "reliability" to determine that the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs. The Commission disagrees.

The Commission finds the testimony of the Staff, MNS, and Consumers compelling. As Consumers testifies, the settlement agreement continues the annual solicitation process adopted by the company in its 2018 IRP. 10 Tr 4121. By preserving the solar ramp-up proposed in the original PCA, the settlement agreement adds 250 ZRCs of new solar generation by the 2025/2026 PY, increasing to 852 ZRCs by the 2028/2029 PY. 10 Tr 4350. The settlement agreement provides that Consumers will deploy a new utility-scale battery storage program which will add approximately 71 ZRCs of new capacity to the zone. 10 Tr 4350. Finally, preserving the EWR and DR provisions from Consumers' original PCA, the settlement provides 94 ZRCs of demand-side resources by the 2025/2026 PY, increasing to 2031 ZRCs by the 2028/2029 PY. The settlement also provides for increases in both the demand-side resources and solar resources in later years. 10 Tr 4350.

In addition to these new resources, the settlement agreement provides for the acquisition of the Covert plant, which will transfer approximately 1,114 ZRCs from PJM into MISO Zone 7. 10 Tr 4123, 4225, 4230, 4331. The settlement agreement has the effect of adding approximately 770 ZRCs through the continued operation of Karn Units 3 and 4 until May 31, 2031, consistent with the design lives of those units. 10 Tr 4225, 4334.

MNS provides that "the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected net increase will be at least 923 ZRCs." 10 Tr 4350. The Staff further contends that, "[t]he Company was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7 . . . ," meanwhile the settlement agreement "only retires a portion of that amount, approximately 1500 MW . . . ." 10 Tr 4405. The projections by both MNS and the Staff are in addition to any resources that may be acquired through the one-time solicitation, discussed below. 10 Tr 4351-4352, 4406. As Consumers observes, the settlement agreement provides for more capacity in Zone 7 than was included in the company's originally filed PCA. 10 Tr 4230. The Commission thus finds that the settlement agreement provides a reasonable and prudent plan for meeting resource adequacy requirements.

The Commission acknowledges the larger resource adequacy concerns of the objecting parties as valid and timely. The broader resource adequacy of Zone 7 and the MISO region has an impact on both Consumers' customers and the state as a whole. The Commission observes that the

2022/2023 MISO PRA results indicate a capacity shortfall for the MISO North and Central Regions.[5] These auction results indicate that many LSEs in MISO will experience a greater risk of implementing involuntary conservation measures even though many of them would appear to be resource adequate when viewed as a stand-alone entity. While the market construct within MISO allows for the pooling of resources to lower the total cost to customers, this market construct means that the planned retirements and resource decisions of one utility impact the customers of other utilities within the Zone and the greater regional transmission organization (RTO).

While the Commission agrees with Consumers' assertion that the company is not responsible for the reliability of the entirety of MISO Zone 7, it is also clear that a deficiency in any part of Zone 7 would increase the likelihood of grid outages for all customers in Zone 7, including those served by Consumers.

As noted above, however, the approval of the settlement agreement enhances zonal resource adequacy in the short, medium, and long term(s). In the short term, the acquisition of the Covert plant will transfer approximately 1,114 ZRCs from PJM into MISO, providing much needed additional capacity to LRZ 7 for the next MISO PY. In the long term, as noted by Mr. Jester, "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. And as the Staff noted, the settlement agreement represents "a resource adequacy improvement over the Company's original PCA[,]" and provides for approximately 400 ZRCs of new resources within

[5] The resources in the MISO region operate as a shared pool of resources to meet the PRMR. As demonstrated in the MISO 2022/2023 PRA results, capacity shortfalls in four MISO Zones resulted in the entirety of the MISO North/Central Regions having a slightly increased risk of needing to implement temporary controlled load sheds. The 2022/2023 PRA results are available at: https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf (accessed, June 17, 2022).

MISO Zone 7 by 2025, in addition to the one-time solicitation for 700 MW set forth in the settlement agreement. 10 Tr 4405, 4406. Finally, while acknowledging the challenges to resource adequacy that were highlighted in MISO's recent PRA results, the Commission notes Consumers' testimony that it "will file at least one, if not multiple, IRPs" between now and when any projected shortfalls are likely to occur, and that it will have "ample time to respond and adjust the PCA" if necessary. 10 Tr 4143-4144. As such, the Commission is satisfied that the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term.

In order to ensure future IRPs appropriately consider zonal resource adequacy in addition to the resource requirements of a particular utility, the Commission directs the Staff to include a requirement for each utility to consider the impacts of its PCA on the resource adequacy of its own customers, the LRZ in MISO or its equivalent in PJM, and also assess the potential impacts, if any, of its decisions on customers in neighboring Zones, regions, or RTOs in the upcoming IRP filing requirements update in Case No. U-18461 in order to better enable the Commission to determine whether future PCAs meet resource adequacy needs of the LRZ.

B. <u>The One-Time Solicitation</u>

The parties objecting to the settlement agreement also express concerns regarding the one-time solicitation as it is outlined in the settlement agreement. Among the concerns, Energy Michigan asserts that the 500 ZRC capacity need that Consumers is seeking to fill through the first tranche of the one-time solicitation will result in capacity that is not additional to what is already being counted toward MISO Zone 7's resource adequacy requirements. 10 Tr 4297. The BMPs and WPSC express concerns that the timing and framing of the one-time solicitation will not result in new resources being added to the market. Specifically, these two parties assert that it will not be possible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing, and construct a new plant by 2025, as the settlement agreement requires the generation to provide Consumers with a capacity credit in MISO Zone 7 by 2025. The Commission finds that this reasoning for denying the settlement agreement is speculative. As several parties contended, the terms of the settlement agreement require that the resources acquired be competitively sourced. The Commission finds persuasive testimony that "respondents to the solicitation could be from some of the projects currently in the MISO queue . . . that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3." 10 Tr 4404 (footnote omitted). And further that "there are more than 13,011 MWs of solar, battery, and solar/battery hybrid projects located in MISO Zone 7 that have an application in-service date by or before June 1, 2025 . . . . Of these projects, 5,365 MW of solar, 499 MW of solar/battery hybrid, and 370 MW of battery have completed Phase 2 or Phase 3 interconnection studies and are therefore highly likely to proceed if the developer has an offtake or build-transfer agreement." 10 Tr 4363-4364 (footnotes omitted). The Commission finds that the one-time solicitation is in the public interest as it is likely to contribute to—or at a minimum not be detrimental to—the overall resource adequacy of MISO Zone 7.

However, to clarify, the Commission does not interpret the language of the settlement agreement to mean that it is pre-judging any approval requests it may receive from Consumers as a result of this one-time solicitation or any other approval requests that Consumers may file following the implementation of its PCA. The language of the settlement reads:

> [T]he actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
>
> > In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery

> of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated 7 with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

Settlement Agreement, pp. 6-7. As such, the Commission will examine the results of the one-time solicitation carefully and will scrutinize any effects it may have on resource adequacy and competitive pricing in Zone 7.

Having addressed each of the arguments as to whether the settlement agreement is in the public interest and represents a fair and reasonable resolution of the proceeding, the Commission finds that, for all the reasons set forth, the settlement agreement is in the public interest. The Commission also finds that the proposed settlement agreement is a fair and reasonable resolution of this proceeding. In addition, having read the record, the Commission likewise finds the settlement agreement to be supported by substantial evidence on the record as a whole. Moreover, as agreed to by the parties in paragraph 1 of the settlement agreement and supported by the record, the Commission finds that Consumers' PCA as amended by the settlement agreement is the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8).

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Exhibit A, is approved.

B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.

C. The Commission Staff shall include a requirement for each affected utility to consider the impacts of its proposed course of action on the resource adequacy of its own customers, the Midcontinent Independent System Operator, Inc. Local Resource Zone or respective PJM

Interconnection, L.L.C. Zone, and neighboring Zones, regions, or regional transmission organizations in the updated integrated resource plan filing requirements to be filed on June 30, 2022, in Case No. U-18461, as outlined in this order.

D. In accordance with paragraph 11(g) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 11(g), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General – Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

____
Daniel C. Scripps, Chair

____
Tremaine L. Phillips, Commissioner

By its action of June 23, 2022.

____
Lisa Felice, Executive Secretary

EXHIBIT A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting approval of the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge ("ALJ") Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff ("Staff"); the Attorney General; Hemlock Semiconductor Operations, LLC ("HSC"); the Biomass Merchant Plants ("BMPs")[1]; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club ("MNS"); Great Lakes Renewable Energy

[1] The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association ("GLREA"), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations ("CEO")); Residential Customer Group ("RCG"); Association of Businesses Advocating Tariff Equity ("ABATE"); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, "Michigan EIBC/IEI/CGA"); Energy Michigan, Inc. ("Energy Michigan"); Midland Cogeneration Venture Limited Partnership ("MCV"); Michigan Electric Transmission Company, LLC ("METC"); Michigan Public Power Agency ("MPPA"); Wolverine Power Supply Cooperative ("Wolverine"); the Citizens Utility Board ("CUB"); the Mackinac Center for Public Policy ("Mackinac"); and the Urban Core Collective ("UCC"). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company's IRP Proposed Course of Action ("PCA") in its entirety, as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

(i.) Approve Consumers Energy's PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;

(ii.) Approve the Company's acquisition and proposed purchase costs for the New Covert Generating Facility ("Covert Plant") and Dearborn Industrial Generation ("DIG Plant"), the Livingston Generating Station ("Livingston Plant"), and the Kalamazoo River Generating Station ("Kalamazoo Plant"), in the manner proposed by the Company, and proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP;

(iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

(iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;

(v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;

(vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;

(vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and

(viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR ($23,751,000), CVR ($9,736,315), and the purchase of the Covert Plant ($815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits ("ZRCs")) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

3. The parties agree to the approval of the battery deployment program as proposed by Company witness Richard T. Blumenstock. The parties agree that the Company will conduct stakeholder outreach to solicit feedback regarding the battery deployment program prior to the issuance of the first battery deployment program competitive solicitation. The approval to recover the costs associated with the batteries acquired in the battery deployment program will be sought in future electric rate cases.

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. ("MISO") or other emergent issues within the Company's generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and

b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;

b. The One-Time Solicitation will include two all source tranches:

   i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and

   ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.

c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;

   i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at $26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and

b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;

b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled "Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and "Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination." The "Objective" of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission's adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;

d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;

e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;

f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company's next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);

g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;

h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company's competitive bidding process, the parties agree that the Company will, to the extent reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and

j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;

b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;

c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;

d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;

f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and

g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate $2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund ("VRR"). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level ("FPL"), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company's next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds ("VOCs"), and primary particulate matter ("PM2.5");

b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant's emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;

c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool ("EJSCREEN"), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;

d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;

e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and

f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;

b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;

c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;

d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;

e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;

f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;

g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;

h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;

i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered, addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;

b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;

c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and

d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler Digitally signed by Spencer Sattler Date: 2022.04.19 14:00:30 -04'00'

Date: April 19, 2022

Spencer A. Sattler, Esq.
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Nicholas Q. Taylor, Esq.
Assistant Attorneys General
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Post Office Box 30221
Lansing, MI 48909

CONSUMERS ENERGY COMPANY

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Robert W. Beach
Date: 2022.04.19
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By: ________________________ Date: April 19, 2022

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Bret A. Totoraitis (P72654)
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ATTORNEY GENERAL, DANA NESSEL

By: Celeste R. Gill Digitally signed by Celeste R. Gill Date: 2022.04.19 15:03:37 -04'00' Date: ____________________

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420 East Front Street
Traverse City, MI 49686

GREAT LAKES RENEWABLE ENERGY ASSOCIATION

By: Don L. Keskey ____________________ Date: April 19, 2022

Don L. Keskey, Esq.
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East Lansing, MI 48823

MICHIGAN ENVIRONMENTAL COUNCIL

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By: ______________________________ Date: __April 19, 2022______

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NATURAL RESOURCES DEFENSE COUNCIL

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By: ______________________________ Date: April 19, 2022

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SIERRA CLUB

Michael C. Soules

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By: __________________________ Date: April 19, 2022

Michael C. Soules
Earthjustice
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CITIZENS UTILITY BOARD OF MICHIGAN

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By: ________________________ Date: April 19, 2022

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MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR ENERGY INNOVATION, AND CLEAN GRID ALLIANCE

By: Laura A. Chappelle Digitally signed by Laura A. Chappelle Date: 2022.04.19 12:42:00 -04'00' Date: April 19, 2022

Laura A. Chappelle, Esq.
Justin K. Ooms, Esq.
Timothy J. Lundgren, Esq.
Potomac Law Group
120 N. Washington Square, Suite 300
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MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

By: Richard Aaron Digitally signed by: Richard Aaron DN: CN = Richard Aaron email = raaron@dykema.com C = US O = Dykema Date: 2022.04.19 12:07:55 -04'00' Date: April 19, 2022

Richard J. Aaron, Esq.
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ENVIRONMENTAL LAW & POLICY CENTER, VOTE SOLAR, ECOLOGY CENTER, AND UNION OF CONCERNED SCIENTISTS

By: Margrethe K. Kearney ______________________ Date: April 19, 2022

Margrethe Kearney, Esq.
Environmental Law & Policy Center
146 Monroe Ctr St. NW, Ste 422
Grand Rapids, Michigan 49503

HEMLOCK SEMICONDUCTOR OPERATIONS LLC

By: Jennifer Utter Heston — Digitally signed by Jennifer Utter Heston Date: 2022.04.19 13:15:32 -04'00' ______________________ Date: _April 19, 2022__________

Jennifer Utter Heston, Esq.
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URBAN CORE COLLECTIVE

By: ________________________ Date: 19-April-2022

Nicholas Leonard, Esq.
Andrew Bashi, Esq.
Great Lakes Environmental Law Center
Local Counsel for Urban Core Collective
4444 2nd Avenue
Detroit, MI, 48201

Mark N. Templeton, Esq.
Robert A. Weinstock, Esq.
University of Chicago Law School –
Abrams Environmental Law Clinic
6020 South University Avenue
Chicago, IL 60637

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.

MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody Date: 2022.04.19 12:19:10 -04'00' Date: April 19, 2022

Nolan J. Moody, Esq.
Peter H. Ellsworth, Esq.
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: John Janiszewski

Digitally signed by: John Janiszewski
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Date: April 20, 2022

John A. Janiszewski, Esq.
Dykema Gossett PLLC
201 Townsend Street, Suite 900
Lansing, MI 48933

ATTACHMENT A

ATTACHMENT A

Contract Year	Total Rate ($/MWh)
2019	**$ 55.54**
2020	**$ 57.49**
2021	**$ 59.38**
2022	**$ 61.28**
2023	**$ 63.25**
2024	**$ 65.24**
2025	**$ 67.24**
2026	**$ 69.24**
2027	**$ 71.23**
2028	**$ 73.18**
2029	**$ 75.08**
2030	**$ 76.95**

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21090

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on June 23, 2022 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 23rd day of June 2022.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-21090

Name	Email Address
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Consumers Energy Company 2 of 2	michael.torrey@cmsenergy.com
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Tracy Jane Andrews	tjandrews@envlaw.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 10

Blumenstock 2023 Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application
of CONSUMERS ENERGY COMPANY Case No. U-21389
for authority to increase its rates
for the generation and distribution Volume 4
of electricity and for other relief.

______________________________________/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Wednesday, October 11, 2023 at 10:04 a.m.

APPEARANCES:

GARY A. GENSCH, JR., ESQ.
MICHAEL C. RAMPE, ESQ.
One Energy Plaza Drive
Jackson, Michigan 49201

On behalf of Consumers Energy Company

NICHOLAS TAYLOR, ESQ.
ANNA STIRLING, ESQ.
AMIT SINGH, ESQ.
MONICA STEPHENS, ESQ.
ALENA CLARK, ESQ.
Assistant Attorneys General
7109 West Saginaw Highway, Floor 3
Lansing, Michigan 48909

On behalf of Michigan Public Service Commission Staff

(Continued)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-21389
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2023

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Supply Engineering. I began employment at the Company in May 1994 in the electric transmission planning area where I performed planning studies on the Company's distribution and transmission systems. In April 2002, I was assigned to the electric operations area where I oversaw engineering operations for the distribution and transmission systems. In August 2009, I was assigned to the fuel supply area where I oversaw the Company's purchasing and transport functions for fuel for electric generation. In June 2011, I assumed additional responsibilities including oversight of the Company's interaction in the Midcontinent Independent System Operator, Inc. ("MISO") markets; wholesale settlements and transactions functions; Power Supply Cost Recovery ("PSCR") activities; and planning for electric supply necessary to satisfy customers' energy and capacity needs. In September 2019, I assumed the role of Executive Director of Electric Planning, overseeing the company-wide efforts for all electric planning. In September 2022, I assumed my current position as Executive Director of Electric Supply Engineering.

Q. What are your responsibilities as Executive Director of Electric Supply Engineering?

A. My responsibilities as Executive Director of Electric Supply Engineering include oversight of all activities associated with planning and design for the Company's electric generation portfolio.

Q. What is your formal educational experience?

A. I received a Bachelor of Science degree in 1992 and a Master of Science degree in 1994, both in Electrical Engineering from Michigan Technological University.

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

A. Yes, I provided testimony in the following MPSC cases:

- Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;

- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;

- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan ("IRP") pursuant to MCL 460.6t and for other relief;

- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief; and

- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department ("Generation") requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy's coal-, oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;

- Support the Company's generation asset strategy to: (1) focus continued investment in those generating units (Zeeland Generating Station ("Zeeland Plant"), New Covert Generating Facility ("Covert Plant"), and Jackson Generating Station ("Jackson Plant")) which provide the most long-term economic benefit for customers; and (2) sustain safe and environmentally compliant operations for its coal generating units (J.H. Campbell ("Campbell") Units 1, 2, and 3 and D.E. Karn ("Karn") Units 1 and 2) through their retirement dates;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate ("ROR") projections for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation, for the projected test year ending February 28, 2025;

- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;

- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;

- Support the reasonableness and prudence of the O&M expenses for the Karn Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2022, the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025;

- Support the reasonableness and prudence of the O&M expenses for the Campbell Units 1, 2, and 3 retention and separation incentives for the 14-month bridge period beginning January 1, 2023 and ending February 29, 2024, and the projected test year ending February 28, 2025; and

- Describe the environmental regulations with which the Company's electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz's testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-39 (RTB-1) and the generating unit availability projections in Exhibit A-40 (RTB-2). Company witness

Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the IRP competitive solicitation process and timeline associated with the IRP solar initiative investment, including the build transfer agreements ("BTAs") and their associated projected capital expenditures.

Company witness Adam J. Monroe supports capital investments in river hydroelectric facilities, including the Hardy Dam.

Company witness Josnelly C. Aponte supports the creation of a regulatory asset for the recovery of retention and separation expenses at both the Karn and Campbell sites in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-39 (RTB-1)		Generating Unit Periodic Outages;
Exhibit A-40 (RTB-2)		Generating Unit Availability Projections;
Exhibit A-12 (RTB-3)	Schedule B-5.1	Summary of Actual and Projected Electric Capital Expenditures for the Years 2022 through February 2025; and
Exhibit A-41 (RTB-4)		Summary of the Generation O&M Expense for the Years 2022 through February 2025.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and its generating asset projected performance metrics. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives and also the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of December 21, 2022, the Company's total projected owned generation assets for the 2023/2024 Planning Year had a Generator Verification Test Capacity ("GVTC") of 6,647 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2025	260
JH Campbell 2	West Olive, MI	1967	2025	350
JH Campbell 3*	West Olive, MI	1980	2025	784 (owned share)
OIL OR GAS FIRED				
Covert	Covert, MI	2004	2040	1089
DE Karn 3	Essexville, MI	1975	2031	298
DE Karn 4	Essexville, MI	1977	2031	592
Zeeland CC	Zeeland, MI	2002	2041	532
Zeeland 1A	Zeeland, MI	2002	2041	159
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	535
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	2
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	32
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	3
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	1
RENEWABLES				
Lake Winds	Mason County, MI	2012	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	2048	
Crescent Wind	Jonesville, MI	2021	2051	166
Gratiot Farms Wind	Alma, MI	2021	2051	150
Solar Gardens- GVSU	Grand Rapids, MI	2016	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	2051	0.5
Circuit West	Grand Rapids, MI	2019	2049	0.5
ENERGY STORAGE				
Ludington Units 1-6**	Ludington, MI	1973	2069	1160 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("LPS" or "Ludington") Units 1 through 6?

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 1,160 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous electric rate case, Case No. U-21224?

A. Yes. The retirement dates for Karn Units 3 and 4 reflect different retirement dates. The Company filed its 2021 IRP in Case No. U-21090 on June 30, 2021 and in its Proposed Course of Action ("PCA"), the Company proposed the retirement of Karn Units 3 and 4 by May 31, 2023, coincident with the retirement of Karn Units 1 and 2. However, the Settlement Agreement reached in the 2021 IRP reflected continued operation of Karn Units 3 and 4 through May 31, 2031. In addition, the Covert Plant was not reflected in the Company's owned generating units in Case No. U-21224 but will be included in the Company's generating resources effective June 1, 2023, as will be discussed in more detail later in this direct testimony. Finally, Karn Units 1 and 2 have been removed due to their pending retirement.

Q. How will the Company continue to meet its load requirements with the retirement of the Campbell units in 2025?

A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant by June 1, 2023, continued operation of Karn Units 3 and 4, and the addition of 700 Zonal Resource Credits ("ZRCs") by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

The Covert Plant is a 1,089 MW natural gas-fired combined cycle generating unit in Van Buren County. The addition of Covert, 700 ZRCs through a one-time solicitation, continued operation of Karn Units 3 and 4, along with Consumers Energy's current natural gas-fired power plants in Zeeland and Jackson — will meet Michigan's energy needs when renewables and other sources are not available.

<u>GENERATION ASSET STRATEGY</u>

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on providing safe, reliable, regulatory compliant, and economic energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs, as approved by the MPSC.

Q. How does the Company's generation asset strategy apply to the Company's various generating units?

A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations. A detailed discussion of River Hydro compliance is discussed in the direct testimony of Company witness Monroe.

Consistent with the approval of the Company's PCA in its 2021 IRP, the Company will concentrate investment on the gas-fired units as they will provide the greatest long-term customer benefit. The coal-fired units will have less investment as they approach retirement. During 2022, the Company's Zeeland and Jackson Plants produced over 27% of the energy value and over 25% of the capacity value realized by the Consumers Energy generating fleet (excluding renewables). The addition of the Covert Plant on June 1, 2023 will significantly increase the energy and capacity value for the Company's gas-fired generation. As such, the Company's investment focus and associated performance projections, have been correspondingly set for these generating units.

Q. How does the Company's generation asset strategy apply to the balance of the Company's generating units?

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value and, consistent with the Company's currently approved IRP expected retirement dates. The Company will continue to maintain its generating units, including the River Hydros, to ensure safe and environmentally compliant operations. With the exception of the River Hydros, I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony describing projected generating unit availability. Company witness Monroe will provide additional detail regarding the Company's generation asset strategy for the River Hydros.

PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS, AND NET ENERGY VALUE

Q. Please describe Exhibit A-39 (RTB-1).

A. Exhibit A-39 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending February 28, 2025, for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-40 (RTB-2).

Q. Please describe Exhibit A-40 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-40 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's coal generation, peaking generation, and hydraulic power generation for the projected test year beginning March 1, 2024 and ending February 28, 2025. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

Q. What factors cause an increase or decrease in ROR?

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates decreases ROR. Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

Q. How are ROR projections for the Generating units developed?

A. The ROR projections for the projected test year ending February 28, 2025 were developed from the five-year (2018-2022) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-40 (RTB-2), column (b).

Q. Please define PF.

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the combustion of a coal blend with a lower heat content than is required to achieve the net demonstrated capability of the unit.

Q. What strategy does the Company employ to minimize the impact of planned outages on its customers?

A. Consistent with the Company's generation asset strategy, the Company endeavors to schedule planned generating unit outages during periods in which the margin between the generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand. However, with the introduction of seasonal capacity in the MISO market, the Company will also consider the impact of outage scheduling on capacity accreditation for the four capacity seasons. Company witness Metz describes seasonal capacity in more detail in her testimony.

Q. Does this outage scheduling strategy apply to all of the Company's generating units?

A. No. For those generating units which have higher production costs and, as a result, are less likely to be dispatched, the available window for scheduling generating unit outages is much larger. The specific strategy for each generating unit or category of generating units will be discussed in more detail later in this testimony.

Q. Please define Projected Availability.

A. Projected Availability is a measure of the percent of time that a generating unit or category of generating units is projected to be available to generate electricity.

Q. How is Projected Availability determined for each generating unit or category of generating units?

A. The Projected Availability for each generating unit or category of generating unit is a simple combination of the PF and the projected ROR. Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

Q. How does the Company's generation asset strategy inform Projected Availability?

A. As I previously discussed, our generation asset strategy and associated generation investment will focus on each unit's ability to provide economic value to customers through the unit's ability to produce energy and capacity value in the respective MISO markets. As such, those generating units or category of generating unit providing the greatest amount of economic value to customers will be targeted to achieve the highest projected availabilities.

Q. How can the Company impact Projected Availability for a generating unit?

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

Q. Does the Company attempt to maximize availability for all its generating units or category of generating units?

A. No. Consistent with the Company's generation asset strategy, the Company focuses on sustaining availability for those generating units which provide the greatest economic benefit to customers through the energy value provided. The Company's generating units get dispatched by MISO as part of the MISO energy market. Based upon the Company's projected dispatch likelihood for each unit, the Company will rank the generating units from highest economic value to least economic value, and manage the PF and the ROR, and therefore the unit's Availability, to allow for the highest customer value. Or, stated differently, the PF and ROR values may be allowed to be higher (lower unit Availability) for the lower economic value units, and will be managed to lower values (higher unit Availability) for higher economic value units.

Q. How does the Availability projection reflect the customer benefit?

A. An improvement in Availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis. Additionally, higher availability increases the ZRCs, increasing the capacity value of the unit.

Q. How does the Company measure the customer benefit resulting from increased generation?

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-40 (RTB-2), column (f), which identifies five-year (2018-2022) actual NEV amounts.

Q. What can the Company do to positively affect NEV?

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

Q. Does the cost of production vary for the Company's generating units?

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for our customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

Q. Why is the measurement of NEV important to the Company and its customers?

A. Positive NEV reflects a direct and immediate reduction to customer power supply costs and consideration of NEV provides a basis for making operational and financial decisions in order to maximize the customer value of the generating unit.

Q. What is another measure the Company uses to evaluate economic projects for its generating units?

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the capacity value of the Company's generating units in the 2022-2023 PRA for Zone 7. Company witness Metz discusses the capacity value of the Company's generating units in the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC[1] MW	MISO SUMMER SAC[2] MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[3]	CAPACITY VALUE ZONE 7 (75% CONE)[4]
COAL FIRED					
JH Campbell 1	West Olive, MI	260	245.3	$ 21,189,235	$ 15,891,926
JH Campbell 2	West Olive, MI	350	271.6	$ 23,461,052	$ 17,595,789
JH Campbell 3	West Olive, MI	784.4 (owned share)	663.5	$ 57,313,727	$ 42,985,295
OIL OR GAS FIRED					
Covert	Covert, MI	1088.6	1058.5	$ 91,434,183	$ 68,575,637
DE Karn 3	Essexville, MI	298	207.1	$ 17,889,484	$ 13,417,113
DE Karn 4	Essexville, MI	591.9	394.5	$ 34,077,265	$ 25,557,949
Zeeland CC	Zeeland, MI	532.1	522.1	$ 45,099,468	$ 33,824,601
Zeeland 1A	Zeeland, MI	159.4	168.1	$ 14,520,629	$ 10,890,472
Zeeland 1B	Zeeland, MI	158.8	167.5	$ 14,468,801	$ 10,851,601
Jackson	Jackson, MI	535.3	539.8	$ 46,628,410	$ 34,971,307
HYDROELECTRIC					
Alcona	Alcona County, MI	3	3	$ 259,143	$ 194,357
Allegan	Allegan County, MI	1.1	1.1	$ 95,019	$ 71,264
Cooke	Iosco County, MI	7.1	6.8	$ 587,390	$ 440,543
Croton	Newaygo County, MI	2.3	2.3	$ 198,676	$ 149,007
Five Channels	Iosco County, MI	6.3	6.1	$ 526,923	$ 395,193
Foote	Iosco County, MI	2.9	3	$ 259,143	$ 194,357
Hardy	Newaygo County, MI	32.4	31.5	$ 2,720,998	$ 2,040,749
Hodenpyl	Wexford County, MI	4.5	4.5	$ 388,714	$ 291,536
Loud	Iosco County, MI	4.9	4.7	$ 405,990	$ 304,493
Mio	Oscoda County, MI	1.7	1.8	$ 155,486	$ 116,614
Rogers	Mecosta County, MI	2.3	2.4	$ 207,314	$ 155,486
Tippy	Manistee County, MI	6.2	6.2	$ 535,562	$ 401,671
Webber	Ionia County, MI	1	1	$ 86,381	$ 64,786
RENEWABLES					
Lake Winds	Mason County, MI	100.8	13.3	$ 1,148,866	$ 861,649
Cross Winds (Phase I)	Tuscola County, MI	110.98	15.8	$ 1,364,818	$ 1,023,614
Cross Winds (Phase II)	Tuscola County, MI	43.7	6.2	$ 535,562	$ 401,671
Cross Winds (Phase III)	Tuscola County, MI	75.9	10.8	$ 932,914	$ 699,685
Crescent Wind	Jonesville, MI	166	7.6	$ 656,495	$ 492,371
Gratiot Farms Wind	Alma, MI	150	9.7	$ 837,895	$ 628,421
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	$ 146,848	$ 110,136
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	$ 51,829	$ 38,871
Cadillac Solar Garden	Cadillac, MI	0.5	0.3	$ 25,914	$ 19,436
Circuit West	Grand Rapids, MI	0.5	0.3	$ 25,914	$ 19,436
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1159.6 (owned share)	1117.2	$ 96,504,741	$ 72,378,556

1 ISAC = Intermediate seasonal accredited capacity
2 SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours
3 2022-2023 PRA Settlement price of $236.66/MW-day for Zone 7.
4 2022-2023 PRA 75% CONE price of $177.50/MW-day for Zone 7.

Q. Please provide an overview of the generation asset strategy for Campbell Units 1 and 2.

A. The strategic plan for Campbell Units 1 and 2 is predicated on their planned retirement on May 31, 2025, as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Units 1 and 2 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact their projected performance?

A. It is anticipated that the unit performance will degrade from current performance for both Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units near retirement. Based upon the Campbell Units 1 and 2 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 16.00% at Campbell Unit 1 and 14.50% at Campbell Unit 2 in the test year, as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (c). During the five-year historical period from 2018 through 2022, Campbell Unit 1 had an ROR of 15.56% and Campbell Unit 2 had an ROR of 17.33% as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Units 1 and 2 in the test year?

A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 78.23% and 70.12%, respectively, as shown on Exhibit A-40 (RTB-2), lines 1 and 2, column (e). The Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF of 6.87%, as shown on Exhibit A-40 (RTB-2), line 1, columns (c) and (d). The planned Campbell Unit 1 outage for the test year is scheduled to begin on October 11, 2024 and last for 25 days. Projected Availability for Campbell Unit 2 reflects a projected ROR of 14.50% and a PF of 17.99%, as shown on Exhibit A-40 (RTB-2), line 2, columns (c) and (d). The planned Campbell Unit 2 outage for the test year is scheduled to begin on April 1, 2024 and last for 30 days, as reflected on Exhibit A-39 (RTB-1), line 3. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How does the availability for Campbell Units 1 and 2 translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2018 through 2022, Campbell Unit 1 had an NEV of $96.8 million and Campbell Unit 2 had an NEV of $89.6 million. The 2022 NEV for each of these units was $54.0 million and $61.6 million for Campbell Units 1 and 2, respectively.

Q. Please quantify the capacity value for Campbell Units 1 and 2.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $21.2 million for Campbell Unit 1 and $23.5 million for Campbell Unit 2. The hypothetical capacity value upon which the Company plans its capacity resources (75% of Cost of New Entry ("CONE") for Zone 7 in the 2022-2023 PRA is $15.9 million for Campbell Unit 1 and $17.6 million for Campbell Unit 2.

Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.

A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31, 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Capital projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its projected performance?

A. It is anticipated that unit performance will remain relatively consistent with current performance. Based upon the Campbell Unit 3 capital and major maintenance projects discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on Exhibit A-40 (RTB-2), line 3, column (c). During the five-year historical period from 2018 through 2022, Campbell Unit 3 had an actual ROR of 11.70%, as shown on Exhibit A-40 (RTB-2), line 3, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Unit 3 in the test year?

A. The Projected Availability for Campbell Unit 3 in the test year is 84.44%, as shown on Exhibit A-40 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 8.00% and a PF of 8.22%, as shown on Exhibit A-40 (RTB-2), line 3, columns (c) and (d). The planned outage for the test year is scheduled to begin on April 16, 2024 and last for 30 days, as reflected on Exhibit A-39 (RTB-1), line 4. The outage is scheduled during a period in which energy prices are projected to be lower, thereby reducing the impact of the outage on customers.

Q. How does the Campbell Unit 3 Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), line 3, column (f), during the five-year historical period from 2018 through 2022, Campbell Unit 3 had an NEV of $365.3 million. The 2022 NEV for Campbell Unit 3 was $190.2 million.

Q. Please quantify the capacity value for Campbell Unit 3.

A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $57.3 million and the Campbell Unit 3 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $43.0 million.

Q. Please provide an overview of the generation asset strategy for Karn Units 1 and 2.

A. The strategic plan for Karn Units 1 and 2 is predicated on their planned retirement on May 31, 2023 as documented in the Company's approved Settlement Agreement in the Company's 2018 IRP, Case No. U-20165. The overall remaining life objective for Karn Units 1 and 2 is to maintain economic dispatch from the customer's perspective. Economic O&M expenses through retirement on May 31, 2023, are targeted to maintain operable, safe, and regulatory compliant units through their retirement date. No capital expenditures are included in the plan.

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their projected performance?

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 16.50% at Karn Unit 3 and 17.50% at Karn Unit 4 in the test year, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (c). During the five-year historical period from 2018 through 2022, Karn Unit 3 had an ROR of 36.05% and Karn Unit 4 had an ROR of 29.51%, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in the test year?

A. The projected availabilities for Karn Units 3 and 4 in the test year are 61.02% and 73.90%, respectively, as shown on Exhibit A-40 (RTB-2), lines 4 and 5, column (e). The availability for Karn Unit 3 reflects a projected ROR of 16.50% and a PF of 26.92%, as shown on Exhibit A-40 (RTB-2), line 4, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 1, 2024 and last for 43 days, as reflected on Exhibit A-39 (RTB-1), line 1. The availability for Karn Unit 4 reflects a projected ROR of 17.50% and a PF of 10.43%, as shown on Exhibit A-40 (RTB-2), line 5, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 31, 2024 and last for 38 days, as reflected on Exhibit A-39 (RTB-1), line 2.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 4 and 5, column (f), during the five-year historical period from 2018 through 2022, Karn Unit 3 had a NEV of -$8.1 million and Karn Unit 4 had a NEV of -$11.1 million. The 2022 NEV for each of these units was -$0.9 million and -$4.1 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative for several reasons, including the need to perform unit demonstration testing, unit performance, and conduct operator training. Due to the production cost for the units, the units get dispatched far less than the Company's other generating assets. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of value in the form of relatively cheap capacity, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $17.9 million for Karn Unit 3 and $34.1 million for Karn Unit 4. The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $13.4 million for Karn Unit 3 and $25.6 million for Karn Unit 4.

Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Zeeland Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-40 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2018 through 2022, the Zeeland Plant had ROR values at or below 4.77% for all units, as shown on Exhibit A-40 (RTB-2), lines 13 through 15, column (b).

Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in the test year?

A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the Zeeland Plant in the test year is 90.79%, as shown on Exhibit A-40 (RTB-2), line 13, column (e). The Zeeland combined cycle (Units 3, 4, and 5) generating unit availability is based upon a projected ROR of 4.0% and a PF of 5.43%, as shown on Exhibit A-40 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for the simple cycle generating units at the Zeeland site in the projected test year are 93.73% and 92.75%, respectively, as shown on Exhibit A-40 (RTB-2), lines 14 and 15, column (e). The Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 2.36% and 3.39%, respectively, as shown on Exhibit A-40 (RTB-2), lines 14 and 15, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending February 28, 2025, however there are several shorter duration outages of 10 days each scheduled in May and October. There are also no outages greater than 28 days scheduled for the Zeeland simple cycle units (Units 1 and 2) however several shorter planned outages are scheduled for those units in April and May 2024, lasting a total of nine days for Unit 1 and 13 days for Unit 2. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How does the Zeeland Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 13 through 15, column (f), during the five-year historical period from 2018 through 2022, the Zeeland Plant provided a total NEV of $197.3 million. The 2022 NEV for Zeeland was $89.0 million.

Q. Please quantify the capacity value for the Zeeland Plant.

A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $74.1 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $55.6 million.

Q. Please provide an overview of the generation asset strategy for the Jackson Plant.

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Jackson Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on Exhibit A-40 (RTB-2), line 16, column (c). During the five-year historical period from 2018 through 2022, the Jackson Plant had an actual ROR of 6.38%, as shown on Exhibit A-40 (RTB-2), line 16, column (b).

Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in the test year?

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 91.25%, as shown on Exhibit A-40 (RTB-2), line 16, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 4.45%, as shown on Exhibit A-40 (RTB-2), line 16, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in the test year, however a short 12-day outage is scheduled to begin September 29, 2024. In addition, several derates are scheduled to perform inspections and maintenance on various generating units in April and September 2024.

Q. How does the Jackson Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), line 16, column (f), during the five-year historical period from 2018 through 2022, the Jackson units provided a total NEV of $152.0 million. The 2022 NEV for the Jackson Plant was $74.2 million.

Q. Please quantify the capacity value for the Jackson Plant.

A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $46.6 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $35.0 million.

Q. How will the Company's generation asset strategy for the Covert Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with past performance under different ownership. Based upon the Covert Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 0.96% to 1.74% at the Covert Plant in the test year, as shown on Exhibit A-40 (RTB 2), lines 17 through 19, column (c).

Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the test year?

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 93.07% to 93.81%, as shown on Exhibit A-40 (RTB-2), lines 17 through 19, column (e). The Covert combined cycle generating unit availability is based upon projected ROR of 0.96% to 1.74% and a PF of 5.28%, as shown on Exhibit A-40 (RTB-2), lines 17 through 19, columns (c) and (d). There are no outages greater than 28 days scheduled for the Covert Plant combined cycle units (Units 1, 2, and 3) in the projected test year ending February 28, 2025, however there is a shorter duration outage of 19 days scheduled for each unit. These outages are scheduled for October and November 2024, periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers.

Q. How will the Covert Plant Projected Availability translate into customer value?

A. The Company projects that the Covert Plant combined cycle units will provide NEV that is approximately twice that of the Jackson and Zeeland Combined Cycle Units.

Q. Please quantify the capacity value for the Covert Plant.

A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $91.4 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $68.6 million.

Q. Please provide an overview of the generation asset strategy for the River Hydro units.

A. A full discussion of the Company's River Hydro generation asset strategy is included in the direct testimony of Company witness Monroe.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Company has recently completed a major overhaul of the Ludington units which is intended to provide increased capacity and generation, increased efficiency, and an extended service life which directly supported the 50-year Federal Energy Regulatory Commission ("FERC") license extension. The value for these units resides primarily in the resource adequacy market (capacity market) with the ability to generate power rather instantaneously when electric energy prices are high, or pump power rather instantaneously when electric energy prices are low. The overall long-term objective for Ludington is to maintain reliable reserve capacity for customers. The capital expenditures and major maintenance expenses in the plan are targeted to increase unit capacity and efficiency and provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be considered if they provide significant value to customers. Ludington is also a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. It is anticipated that Ludington performance will remain relatively consistent with current performance through the projected test year. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, as well as the Ludington unit major overhauls performed over the past eight years, the Company's generation asset strategy is expected to result in an ROR of 4.00% for the Ludington units in the test year, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (c). During the five-year historical period from 2018 through 2022, the Ludington units had average ROR values ranging from 1.70% to 9.30%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (b).

Q. How do the Ludington Pumped Storage Units factor into the Company's future renewable energy strategy as outlined in the IRP?

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio. Ludington can deliver a significant amount of energy in a short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy.

Q. How is this strategy reflected in the Projected Availability for Ludington in the test year?

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 79.52% to 87.44%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 4.00% and PFs ranging from 8.92% to 17.17%, as shown on Exhibit A-40 (RTB-2), lines 6 through 11, columns (c) and (d). There are two major outages planned for the Ludington units that will begin in the test year; Ludington Units 3 and 4 each have an outage scheduled to begin on February 10, 2025 and last 120 days, as reflected on Exhibit A-39 (RTB-1), lines 6 and 7. In addition, shorter outages on all six Ludington units are scheduled throughout the test period. The outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

Q. How does the Ludington Unit Projected Availability translate into customer value?

A. As reflected on Exhibit A-40 (RTB-2), lines 6 through 11, column (f), during the five-year historical period from 2018 through 2022, the Ludington units provided a total NEV of $32.8 million. The 2022 NEV for Ludington was $23.8 million.

Q. Please quantify the capacity value for Ludington.

A. As reflected in Table 2, the Ludington capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $96.5 million and the Ludington hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $72.4 million.

Q. Please provide an overview of the generation asset strategy for the Renewable Energy Assets.

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, is entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement. Consistent with the IRP, the strategy for the wind assets is to complete construction and have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With respect to solar, the Company plans to continue to add incremental solar resources in accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations, as discussed in more detail later in this direct testimony. In addition, the Company anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027[1] in support of the Company's voluntary green pricing program and their costs will be reconciled through the Company's renewable energy plan. The overall investment objective for the Company-owned assets is to provide funding for projects as appropriate to maintain economic dispatch and capacity from the customer's perspective. The Company has an energy-based availability target of 91% for its renewable energy wind assets. This availability target considers those periods during which the wind is sufficient to produce energy. The capital expenditures and major maintenance expenses in the plan are targeted to maintain the designed performance level.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. As reflected on Exhibit A-40 (RTB-2), lines 20 through 21, column (f), during the four-year historical period from 2019 through 2022, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of $141.1 million. The 2022 NEVs for Cross Winds Energy Park and Lake Winds Energy Park were $43.1 million and $15.4 million, respectively. As reflected on Exhibit A-40 (RTB-2), lines 22 through 23, column (f), the 2022 NEVs for Gratiot Farms Wind and Crescent Wind were $24.7 million and $23.4 million, respectively. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 2022 NEV for its Solar Garden Assets totaled $914,786.

[1] The Settlement Agreement in the Company's 2021 Renewable Energy Plan Amendment, Case No. U-20984, reflected the addition of up to 500 MW of solar and 500 MW of wind over the period from 2024 through 2027 to support the Company's Large Customer Renewable Energy Program.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2022-2023 PRA is $5.7 million and the renewable asset hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2022-2023 PRA is $4.3 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Metz provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II
ENVIRONMENTAL REGULATIONS
OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

Current (On-going) Environmental Compliance

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case No. U-17735. This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company's existing AQCS complies with?

A. Yes. In April, 2022 the Environmental Protection Agency ("EPA") proposed the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard." If the rule is finalized as proposed, prior to the conclusion of the 2023 ozone season, then there is the potential for an increase of expenses in either the form of purchased nitrogen oxide ("NO_x") allowances, additional reagent for the NO_x

control equipment and/or a combination of the two. The Company will continue to monitor the progress of the proposed rule and evaluate the various options for compliance with the rule.

Q. What are the capital investments and/or O&M expenses the Company is seeking recovery of in this case that are specifically related to air quality control?

A. Any capital and/or O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibit A-12 (RTB-3), Schedule B-5.1.

Q. Are you seeking recovery of any expenses related to the regulation of greenhouse gases from EGUs?

A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings related to the regulation of greenhouse gases, specifically carbon dioxide, from EGUs: (i) repeal of the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule and; (iii) issuance of new Clean Air Act ("CAA") Section 111(d) regulations. This rule was subsequently overturned in litigation, and the EPA issued the final Good Neighbor Plan on March 15, 2023. The Good Neighbor Plan requires reductions in oxides of nitrogen emissions from power plants and industrial facilities for 23 states, including Michigan. The Company is in the process of evaluating the impacts of the Good Neighbor Plan on its fossil generating units.

Environmental Regulations and Compliance Strategy – Waste

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA Citizen Suit Authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows Department of Environment, Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

Q. What are the capital and/or O&M investments Consumers Energy is seeking recovery of in this case that are specifically related to RCRA compliance and/or overall CCR Management?

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The capital and/or O&M required for the management of CCRs under the RCRA that the Company is seeking recovery of can be found in Exhibits A-12 (RTB-3), Schedule B-5.1, and A-41 (RTB-4). Separately, there are closure activities that will continue throughout the test year and beyond; however, those expenses are Cost of Removal and are not included in this filing.

SECTION III
GENERATION CAPITAL EXPENDITURES
OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.1, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation, 2022 through the projected test year - 12 months ending February 28, 2025. Exhibit A-12 (RTB-3), Schedule B-5.1, is a 10-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2022, the Projected 14-month Bridge Period beginning January 1, 2023 and ending February 29, 2024, and the projected test year beginning March 1, 2024 and ending February 28, 2025. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but is presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Page 7 of this exhibit provides a summary of Non-Environmental and All Other Environmental capital expenditures in the Projected 14-month Bridge Period ending February 29, 2024 and the projected test year ending February 28, 2025. Finally, pages 8 through 10 of this exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 7 of this exhibit. Specifically, page 8 of this exhibit presents capital projects for the Historical Period ended December 31, 2022; page 9 of this exhibit presents capital projects for the Projected 14-month Bridge Period beginning January 1, 2023 and ending February 29, 2024; and page 10 of this exhibit presents capital projects for the projected test year ending February 28, 2025.

Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10?

A. Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10, presents the generation type, the generation unit, project type, project classification, class of cost estimate, engineering type, internal or external engineering, project bid issued, budget approval[2], project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly whereas non-routine projects are typically undertaken once every 10 years or longer. The class of cost estimate reflects the Association for the Advancement of Cost Engineering ("AACE") class of the project cost estimate, the engineering type denotes whether the engineering was performed internally or by a third-party engineering firm, the project bid reflects the status of the project bids, and the budget approval reflects the status of internal approval for the project, including projected cost amount.

Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, does not include information for class of cost estimate, engineering type, internal or external engineering, and project bid issued.

Q. What cost information is included on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 8 through 10?

A. Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, includes actual capital project cost, projected contingency, and projected total cost. The projected contingency, if applicable, and projected total cost, were included in Case No. U-21224. Exhibit A-12 (RTB-3), Schedule B-5.1, pages 9 and 10, included the project planned amount, contingency amount, project cost reduction, and projected amount. The project planned amounts were reduced by project reductions and contingency to arrive at the projected amounts.

Q. Please explain the project reduction amount.

A. The projects presented on page 9 of Exhibit A-12 (RTB-3), Schedule B-5.1, reflect a project reduction amount of $6.597 million.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $141.372 million for the historical test year ended December 31, 2022 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (b); $1,370,168[3] million in the projected 14-month Bridge Period ending February 29, 2024 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (e); and $387.888 million in the projected test year ending February 28, 2025 as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (f).

[3] The $815 million acquisition of the Covert Plant accounts for a majority of the capital expenditures in the bridge period.

Q. Please explain how the Company prioritizes its capital investments within Generation.

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, compliance, and continued operation related projects. These projects are considered a mandatory cost of doing business. Safety, regulatory, compliance, and continued operation-related projects provide economic value to customers in that they allow the units to remain in service and avoid potential derates and/or shutdown due to an intervention by various regulators including Occupational Safety and Health Administration ("OSHA"), the EGLE, the EPA, and FERC. In order to minimize the impact of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") for the investments necessary to satisfy service quality, safety, and Federal and State policy requirements.

Q. How does the Company determine whether other projects get approved for funding?

A. In accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce ROR, maintenance cost or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. In other words, the implementation of the project should, at a minimum, result in a marginal customer benefit.

Q. How does the Company evaluate other capital investments, such as economic projects?

A. The Company uses two financial measures, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects within Generation. A complex financial model was developed in-house that allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units.

Q. Does the Company calculate IRRs or PVRs for all projects?

A. No. The Company calculates IRRs or PVRs for economic projects that are not considered required but would yield net benefits to customers. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and result from a reasonable evaluation of alternatives, but because the project must be done for compliance and continued operation, IRR or PVR may not be calculated. When evaluating project alternatives related to regulatory, compliance, and/or continued operations, IRRs or PVRs may be used to rank alternatives.

Q. Please explain what you mean by projects for continued operations.

A. Projects for continued operations refers to projects which are necessary to allow the generating unit to continue to operate through its retirement date. Alternatives for projects necessary for continued operation will generally be evaluated based upon LCBF. For this evaluation, one of the alternatives will include a decision to not perform the project and either retire the unit earlier than projected or operate the unit at a permanent derate.

Q. How does the Company evaluate customer benefits associated with generation-related capital investments?

A. The Company uses replacement power cost estimates and PSCR impacts when evaluating customer benefits. The Company also evaluates ROR and heat rate improvements, which result in increased and/or lower cost generation.

Q. How does the Company evaluate historical events which have impacted availability?

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending February 28, 2025.

Q. Does the Company evaluate customer benefits associated with Outage Schedules?

A. Yes, the Company uses historical market prices to evaluate timing around outages, in an effort to ensure the unit is available during periods in which market pricing is projected to be high.

Q. Is it possible that the Company could experience changes to its scheduled outages and forecasted capital expenditures in the future?

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2022. A review of the outage schedule used in this case identifies seven scheduled outages that begin in March 2024 (18 months after the schedule was approved) and run through

February 28, 2025, 29 months later. During each of these seven scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

Q. Are there other reasons why outage schedule changes occur?

A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices.

Q. Can you provide an example of when circumstances changed?

A. Yes. The Company's fall 2021 outage for Campbell Unit 1 was originally scheduled from September 24, 2021 through November 8, 2021. The outage was deferred to 2022 due to the higher than projected MISO energy prices and the Company's ability to create economic value for its customers through continued operation of the unit. Campbell Unit 1 provided more that $27 million in NEV to customers during 2021, a portion of which was earned during the originally scheduled outage period. The deferred Campbell Unit 1 outage began on February 27, 2022 and lasted 39 days, ending April 8, 2022. The outage was taken for air preheater basket and seal replacement, pulse jet fabric filter ("PJFF") bag replacement, performance of high energy piping surveillance ("HEPS"), and flow accelerated corrosion ("FAC") inspection.

Q. Please describe how the Company determines its generation projected capital expenditure amounts.

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant, and reliable operations of the Company's generating fleet. Projected capital investments are informed by historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

Q. How are projects identified that are discussed later in this direct testimony?

A. Generation System Planners assess the equipment performance and compare that assessment with the generation asset strategy for the generating unit. Upon identification of a potential project, the Planner will complete a project initiation document ("PID"). This document defines the issue, alternatives considered for resolution, intended benefits or consequences avoided, and suggested timing and a cost estimate. The document is reviewed by multiple groups for alignment and ultimately routed for approval for inclusion in the Long Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be scheduled three to five years in the future to align with outages and provide the project execution teams ample time to plan and engineer.

Q. How were the projected capital expenditure amounts developed for each of the projects discussed later in this direct testimony?

A. Each project begins with the creation of a PID. The Planner will provide an initial cost estimate for the project within the PID. The Planner utilizes past experience, contractor cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and studies to provide the best estimate of the costs. This activity typically takes place three to five years prior to the start of project execution.

Q. How are PIDs related to Concept Approval Documents ("CADs")?

A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once the project is included in the LTFP and the project is within a year of start of execution, the CAD is created. The CAD is templated from the PID and updated as necessary. The CAD is then routed for approval to the designated level of management based on project amount and, once approved, the project will be initiated.

Q. Do adjustments to the projected capital investment amounts for each of the projects occur prior to project implementation?

A. Yes. As the project team progresses through the life cycle of a project, there are multiple opportunities to better define project costs. Activities such as detailed engineering, bidding, contractor involvement, and construction all allow for budgets to be better defined. As this definition evolves, the projected capital investments are updated accordingly.

2022 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2022 actual capital expenditure amount of $141.372 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21224?

A. The 2022 actual capital expenditure amount of $141.372 million is $76.480 million below the Company's requested amount in Case No. U-21224. As is discussed later in this direct testimony, the reduction in the Company's actual capital expenditure amount is directly attributable to spending approximately $81.4 million less on solar projects than projected. It is important to note that the projected solar project capital expenditures were not projected to close by the end of the projected test year and were offset by the allowance for funds used during construction ("AFUDC"). As such, the underspend did not impact the revenue requirement. The Company's as-filed 2022 projected capital expenditure amount of $210.910 million was adjusted to $217.852 million in the Company's rebuttal testimony to remove several projects at the Jackson Plant, as they were no longer required, and add several projects at Karn Units 3 and 4 due to the 2021 IRP settlement agreement which continued the operation of Karn Units 3 and 4 through 2031. A compilation of the 2022 projects which have actual capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, compare with the 2022 capital projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7?

A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, with the 2022 projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, reveals that there are six projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, which were not reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7. In addition, there were three projects for 2022 that were reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

Q. Please discuss the 2022 capital projects that were included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, due to the fact that their actual 2022 capital expenditure amount was less than $1 million or the project was not pursued in 2022. The disposition of these capital projects is below:

- Foote Trash Rack Ergonomics ($2,675,000). This project began in 2022 at an actual cost of $793,452. This project is scheduled to be completed in 2024 at a projected cost of $1,466,667 as discussed in the direct testimony of Company witness Monroe;
- 2019 IRP Solar Bid Event ($63,593,000). The actual 2022 capital expenditure was $162,468. A thorough discussion of this project's status is presented in Company witness Clark's direct testimony; and
- 2020 IRP Solar Bid Event ($40,909,000). The actual 2022 capital expenditure was $147,697. A thorough discussion of this project's status is presented in Company witness Clark's direct testimony.

Q. Please discuss the 2022 capital projects that were not included in Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8.

A. The disposition of these capital projects is presented below:

- Campbell Unit 3 Diesel Generator Controls ($1,172,322). This project was scheduled for 2022 but the project estimate was only $186,620. The project costs increased because the original estimate did not include the engineering and integration costs. While the Company had anticipated using a single vendor to provide that information, the Company ultimately had to hire three separate contractors to accomplish the work. As such, a significant amount of engineering for the load center, the panel, and the generator was required, none of which was reflected in the original estimate. In addition, the project experienced cost increases on both material and labor as the project extended through the COVID pandemic time frame and the supply chain disruptions after that;

- Campbell North and South Pigeon Lake Jetties – Concrete and Fence Replacement ($1,003,268). This project was scheduled for 2022 but the project estimate was only $740,000. The project cost increased due to the fact that the work scope increased since the estimate was prepared and also due to the increased cost of materials. 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 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 that connects the jetty to the boardwalk has been washed away. The Company needs safe access to the north and south jetties to install lights and conduct other periodic maintenance and the Company is required to provide safe access to the north jetty for recreational opportunities in accordance with its LPS FERC license. This project was completed for compliance and was not avoidable considering the May 31, 2025 retirement of the Campbell site;

- Jackson long term historical extra work ($3,919,897). This project was scheduled for 2022 but the project estimate was only $950,000. The actual project cost exceeded the projected cost due to findings (including balance piston, air piston manifold, and bearing housing) during the performance of the major overhaul on engine 191-351, findings during semi-annual borescopic inspections requiring remediation (high pressure compressor blading replacement) to ensure continuous operation of existing, in-service engines, and restoration of the LM6000 engine (191-306), including the high pressure turbine, to a serviceable condition. The long-term service agreement ("LTSA") historical extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Mio Downstream Reverse Filter ($1.058,458). This project was scheduled for 2022 but the project estimate was only $570,000. The primary cause of project increase was project bids coming in higher than what was projected in the concept approval for the project. Additional cost increases resulted from wetlands mitigation, change from rip-rap to field stone, and increased loadings.

This was a dam safety project identified and initiated through FERC's Part 12D process. The scope of this project was to install a reverse granular filter downstream of the left embankment over an area that has historically had seepage and boil activity. This system is designed to act as a filter at the embankment toe, extending the seepage path length and minimizing the potential for fine material transport. A downstream area of the left embankment at Mio Dam has a history of sand boils, which can lead to soil piping and cause the dam to fail. Remediation of the soil piping potential is required to help reduce the risk of PFM 1.1 (Left Embankment Failure due to Internal Erosion through Foundation) from occurring. This project was implemented in concert with the Mio Left Retaining Wall;

- LPS 480V Motor Control Center ($1,538,171). This project was scheduled for 2022 but the project estimate was only $845,400. The actual cost of this project increased in 2022 due to the need to expedite the installation of the new Switchgear 5 in 2022 due to the failure of the legacy Switchgear 5 on July 30, 2022 as well as pull forward replacement of the top of dike buried conduit installation. It was determined the site was at risk of not being able to pump/generate should another Switchgear 5 bucket fail. The scope of this project is the replacement of the 20 480V Dike Load Centers ("DLCs") over a six-year period that began in 2020 at a capital expenditure amount of $0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance; and

- 2021 IRP Solar Bid Event – Muskegon Solar Project ($22,788,539). The projected amount was $20,332,607 but it was not included in the Company's request for rate relief in Case No. U-21224. The basis for this project is described in the direct testimony of Company witness Clark.

Q. How did the capital expenditure amount for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, compare to the capital expenditure amount for the projects presented on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7?

A. The total projected capital expenditure for the 2022 projects included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, was $177.975 million net of contingency and the total actual capital expenditures for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, is $118.365 million, a reduction of $59.610 million. An evaluation of the 2022 projects included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, against the actual costs for those projects reveals that with the exception of projected costs for the 2019 and 2020 solar bid event projects (underspent by more than $81 million), the reduction in the spend for the Karn unit separation project ($5.602 million), and the 2021 solar bid event project (overspent by $22.789 million), the projected spending for the large projects was on target. A discussion of the 2019, 2020, and 2021 solar bid event projects (i.e. the Mustang Mile Solar Project, the Washtenaw Solar Project, and the Muskegon Solar Project) is included in the direct testimony of Company witness Clark.

Q. How did the capital expenditure amount for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, impact the 2022 total projected capital expenditure amount of $217.852 million?

A. The $59.610 million decrease in capital expenditures from the $177.975 million net of contingency for the projects presented on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 7, versus the $118.365 million for the projects presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 8, helps explain the difference in the capital expenditure amount of $217.852 million requested in Case No. U-21224 Exhibit A-225 (SAH-7) and the actual 2022 capital expenditure amount $141.372 million requested in this proceeding. The actual amount spent for the Karn Units 3 and 4 separation project, and the actual amount spent for three Hardy projects (discussed later) makes up a majority of the remaining difference.

Q. Were there any major 2022 projects whose capital expenditures were contested and/or not fully included in the Case No. U-21224 Settlement Agreement?

A. Yes. The 2022 projected capital expenditures for three projects at Hardy, (1) Auxiliary Spillway Replacement, (2) Crest Roadway Replacement and Compaction, and (3) Splash Wall Replacement, were limited to engineering costs only, or $5.3 million. The total amount reflected in the Company's original request for recovery was $8.26 million, and the actual 2022 amount for engineering costs totaled $4.057 million.

Q. Did the Case No. U-21224 Settlement Agreement establish other limitations or requirements for the Company's hydroelectric generating facilities?

A. Yes. In addition to the capital expenditure limitation for 2022 as discussed above, the Settlement Agreement limited 2023 cost recovery to projected engineering costs totaling $3.45 million. Further, the Settlement Agreement required the Company to collaborate with the MPSC Staff and the Attorney General to both scope and conduct various analyses of all reasonable options to remediate the condition of the Hardy Dam, prior to commencing construction of the Hardy Dam upgrades.

Q. What specific analyses will be performed?

A. The analyses will include the development of economic business cases for the Hardy Dam which will consider, at a minimum, the feasibility and impacts of (1) full decommissioning and removal, (2) divestiture, (3) permanently lowering the reservoir height, and (4) any other reasonable options that lead to a reduced impact of the Hardy Dam on customer rates. These economic business cases are required to be performed by an external engineering firm with experience in the engineering, construction and decommissioning of dams. Specifically, the economic business cases will assess the value of the energy and capacity that Hardy Dam will provide customers, under a variety of reasonable assumptions, against the revenue requirement associated with the projected capital expenditures and O&M expenses through 2034, the end of Hardy Dam's current FERC license term.

Q. Does the Case No. U-21224 Settlement Agreement include other requirements?

A. Yes. The Settlement Agreement also requires the Company to either perform, or cause to be performed, an economic assessment of the impact of the various options on the Muskegon River Hydroelectric Dam communities. In addition, the Settlement Agreement requires the Company to engage in discussions with the affected local communities regarding both the costs and timing of the proposed projects for the Hardy, Croton, and Rogers Dams, and the need for funding, including potential funding mechanisms, from the affected communities. The performance of these discussions with the affected local communities as well as the potential funding from these local communities, must be shared with the Commission prior to commencing construction.

Q. What are the Company's current plans for commencing construction at the Hardy Dam?

A. As is discussed in more detail in Company witness Monroe's direct testimony, the Company's current plans are to begin construction in the fall of 2025.

<u>CONTINGENCY</u>

Q. Has the Company included any contingency in the requested capital expenditures for Generation?

A. No. However, Exhibit A-12 (RTB-3), Schedule B-5.1, page 4, line 5, columns (c) and (d), presents $0.807 million in total contingencies in the 14-month bridge period ending

February 29, 2024, and $1.083 million in total contingencies in the projected test year ending February 28, 2025.

Q. Why does the Company present contingencies in its individual project capital expenditure amounts?

A. Budgeting for contingency is an accepted Project Management practice. According to the AACE International, contingency is "An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs." Contingency is included in some major project estimates and is expected to be used. It is a real item in a project estimate like any other cost, and as such, should be included as a cost. For these reasons contingency costs are appropriate and should be included in the capital expenditures and, ultimately, rate base in this filing.

Q. Has the Company adjusted its practice for inclusion of contingency in this proceeding?

A. Yes. The Commission has issued multiple orders which did not permit recovery of contingency costs. While the Commission acknowledged that inclusion of contingency costs in project planning may be appropriate, it found that those costs should not be included in rates.

Q. Has the Company included other contingency amounts in its requested capital expenditure amounts?

A. No. While the Company has presented projected contingency amounts of $0.807 million in the 14-month bridge period ending February 29, 2024, and $1.083 million in test year the ending February 28, 2025, these amounts have not been included in the total capital expenditure amounts for which the Company is seeking recovery. Because the Company believes that contingency is a real cost of performing project work, it has presented these amounts in testimony in support of each individual project such that they will align with its concept approval documents. Total contingency is then backed out of capital spending in Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 16. Projected capital spending less contingency is then presented on line 17 of this exhibit. The Company is including this capital spending net of contingency in its requested rate relief.

PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES

Q. How does the projected 14-month bridge period capital expenditure of $1,370 million compare to the amount of capital approved by the MPSC in Case No. U-21224 for 2023?

A. The 14-month bridge period projected capital expenditure amount of $1,370 million is $107 million more than the projected test year amount of $1,263 million requested in the Company's last electric rate Case No. U-21224. The primary contributors to the increase between the 2023 projected test year amount in Case No. U-21224 and the 14-month projected bridge period amount in this case is a $125 million increase in projected capital expenditures for IRP solar bid events as well as the incremental projected capital expenditure amount of $81 million for the two-month period ending February 29, 2024, as presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, line 17, column (d). A compilation of the 14-month bridge period projects which have projected capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, compare with the 2023 capital projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8?

A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, with the 2023 projects reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, reveals that there are 11 projects on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, which were not reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8. In addition, there were 10 projects for 2023 that were reflected on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

Q. Please discuss the 2023 capital projects that were included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, due to the fact that the projected bridge period capital expenditure amounts are now less than $1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is below:

- Campbell Unit 3 Complete Mill Overhauls ($1,295,300). The Company reduced the cost of this project to $552,370 in the 14-month bridge period as part of its capital efficiency efforts which will be discussed in more detail later in this direct testimony. This scope of project will also be discussed in more detail later in this direct testimony;
- Karn Unit 4 distributed control system and simulator upgrade ($1,000,000). The projected cost of this project has been reduced by $100,000 and, as such, is no longer presented on Exhibit A-12 (RTB-3), Schedule B-5.1. The scope of this project is discussed later in this direct testimony;
- Jackson turbine building temperature control replacement ($1,321,968). This project was removed in the Company's rebuttal testimony in Case No. U-21244

due to the current condition of the equipment. The Company invested approximately $100,000 to replace inoperable louvers. As a result of this work, the Company believes that it can invest approximately $20,000 in major maintenance work on an annual basis to keep the turbine building temperature control system operable, thereby obviating the need for this project at this time. The engineering team will re-evaluate this project in the future to ensure annual maintenance resolves the temperature controlling issue and if it is not sufficient, they will develop a future plan and options;

- Alcona Risk Informed Decision Making Resolution ($1,000,000). The projected cost for the bridge period has been reduced to $0.417 million with $2.5 million reflected in the projected test year. The scope of project will also be discussed in more detail later in this direct testimony;

- Alcona Trash Rack Ergonomic Project ($1,160,000). This project has been deferred beyond the test period;

- Foote Governor Replacement ($1,277,000). This project was pulled forward and was completed in 2022 at a total cost of $697,163;

- Loud Spillway Hoist Replacement ($1,043,000). The Company reduced the cost of this project by $50,000 to $993,000 in the 14-month bridge period as part of its capital efficiency efforts which will be discussed in more detail later in this direct testimony. The project is now below the threshold for inclusion on this exhibit. The scope of project will also be discussed in more detail later in this direct testimony;

- Jackson Generator Stator Rewind ($2,400,000). This project was removed in the Company's rebuttal testimony in Case No. U-21224 due to the current condition of the equipment. An inspection performed in Spring 2022 of a corona repair performed in 2021 showed no signs of degradation that would require a stator rewind to be performed in 2023. Another borescopic inspection will be performed in 2024. Beyond 2024, the OEM's in-situ inspections (including visual inspections) will be performed on their five-year planned frequency;

- Webber Unit 1 Overhaul & Generator Rewind ($3,570,000). This project has been deferred to the test period and is discussed in the direct testimony of Company witness Monroe; and

- Zeeland Generator Gas Turbine Rewind ($2,675,000). This project was cancelled and replaced with bridge period projects for the field rewinds at Zeeland Units 3 and 4 which are discussed below in the bridge period project additions and supported later in this direct testimony.

Q. Please identify the 14-month bridge period capital projects that were not included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9.

A. The bridge period capital projects that were not included on Case No. U-21224, Exhibit A-12 (SAH-3), Schedule B-5.7, page 8, include: (1) Karn Units 3 and 4 Tank Farm Storage Tank Heating Line Replacement, (2) Karn Units 3 and 4 Sync Wire Replacement, (3) Zeeland Unit 4 Generator Rotor Field Rewind, (4) Zeeland Unit 3 Field Rewind, (5) Rogers PMF Project, (6) Rogers Unit 4 Generator Rewind, (7) Mio Electrical Safety Project, (8) Webber Left Downstream Spillway Abutment Wall, (9) Ludington Oil Water Separator Replacement, (10) Ludington Distributed Control System ("DCS") Control Relay Replacement, and (11) 2021 Solar Event - Muskegon Solar Project. The basis for projects 1 through 4, 9, and 10 will be discussed in more detail later in this direct testimony, the basis for projects 5 through 8 will be discussed in the direct testimony of Company witness Monroe, and the basis for project 11 will be discussed in the direct testimony of Company witness Clark.

Q. Is the projected capital expenditure amount of $1,370 million for the 14-month bridge period ending February 29, 2024, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, column (c), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (h), $417.180 million of that capital will fund solar projects pursuant to the Company's IRP, $882.950 million of that total capital expenditure amount will be used for the acquisition of the Covert Plant and projects at the Covert, Jackson, and Zeeland plants. Furthermore,

$13.794 million will fund various projects at the LPS, and $36.662 million will fund various hydro safety, reliability, and regulatory compliance projects. With the exception of the solar projects and the river hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The river hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

Q. Do the Company's projected capital expenditures at the Campbell site for the 14-month bridge period ending February 29, 2024, align with the Company's generation asset strategy and the planned retirement of the generating units at that site?

A. Yes. The Company's projected capital expenditures for Campbell Units 1, 2, and 3 for the 14-month bridge period ending February 29, 2024 are significantly reduced from the five-year average capital expenditure amount for the period from 2018 through 2022. The 14-month bridge period capital expenditures for Campbell Units 1 and 2 represents an 87% reduction from the five-year average, the 14-month bridge period projected capital expenditures for Campbell Unit 3 represents a 50% reduction from the five-year average.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $387.888 million for the test year ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.1, page 1, column (d), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.1, pages 2 and 3, lines 1 through 119, column (j),

$269.457 million of that capital will fund solar projects pursuant to the Company's IRP and $47.281 million of that total capital expenditure amount will be used for projects at the Covert, Jackson, and Zeeland plants. Furthermore, $14.137 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019 and $49.897 million will fund various hydro safety, reliability, and regulatory compliance projects. Except for the solar projects and the river hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The river hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

Q. Do the Company's projected capital expenditures at the Campbell site for the test year ending February 28, 2025 align with the Company's generation asset strategy and the planned retirement of the generating units at that site?

A. Yes. As previously discussed, the Company's projected capital expenditures for Campbell Units 1, 2, and 3 for the test year ending February 28, 2025 are significantly reduced from the five-year average capital expenditure amount for the period from 2018 through 2022. The test year projected capital expenditures for Campbell Units 1 and 2 represents a 98% reduction from the five-year average, the test year projected capital expenditures for Campbell Unit 3 represent a 96% reduction from the five-year average.

Campbell Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for Campbell Units 1 and 2.

A. The Company plans to invest a total of $1.723 million in the 14-month bridge period and $0.285 million in the test year on Campbell Units 1 and 2. The projected bridge period amount includes $1.393 million in non-environmental expenditures and $0.330 million in environmental expenditures and the projected test year amount includes $0.272 million in non-environmental expenditures and $0.014 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 1, columns (h) and (j), respectively, and Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 1, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 2, columns (c) and (e), respectively. These capital investments will be facilitated by outages at Campbell Unit 1 in the fall of both 2023 and 2024 and outages at Campbell Unit 2 in the spring of 2023 and 2024. The Campbell Unit 2 outage scheduled for the spring of 2024 is presented on Exhibit A-39 (RTB-1), line 3.

Q. What is the basis for the projected $1.723 million investment in the projected bridge period?

A. The projected $1.723 million investment will fund regulatory compliance and reliability projects. There are no projects whose projected cost is greater than $1 million, but the following projects are important to regulatory compliance and reliability:

- Campbell Unit 1 and Unit 2 Major Motor and Pump Overhauls ($100,000 per unit). This project will overhaul major motors and/or pumps based on established rebuild schedules and equipment condition assessments. Large pumps and motors require overhauls/rewinds on a regular schedule and the work will provide continued equipment reliability through plant retirement on May 31, 2025. Condition assessments of plant equipment are performed on a monthly basis, and it is through that process that the specific pumps and motors requiring overhaul are identified. Upon identification of the specific pumps and motors to be overhauled, unique capital projects are established to perform the work. The performance of this work will maintain unit reliability. This project is being completed for unit reliability and is not considered avoidable;

- Campbell Units 1 and 2 Balance of Plant ("BOP") Equipment Replacements ($200,000 per unit). This project will replace various BOP equipment on Campbell Units 1 and 2 in 2023 based upon condition assessments and the work will provide continued equipment reliability through plant retirement on May 31, 2025. This project is being completed for unit reliability and is not considered avoidable;

- Campbell Unit 2 AQCS Projects ($200,000). This project will complete various AQCS projects at Campbell 2 during the projected bridge period, thereby providing continued equipment reliability and regulatory compliance through plant retirement on May 31, 2025. This project is being completed for air quality regulation compliance and is not considered avoidable;

- Campbell Unit 2 Condensate Pump Overhaul ($215,000). The Campbell Unit 2A Condensate Pump & Motor each require a capital overhaul. The pump was last overhauled in 2006, and industry standards for large pumps suggest overhauls on a 10-year frequency. Significant wear is expected on the pump components based on previous inspection reports of identical pumps (Campbell Unit 2C Condensate Pump, 2018). The pump is experiencing lost performance due to the extended time between overhauls. The motor was last reconditioned in 2016, and while minimal effort is expected for the motor, it is logical to perform the motor inspection/overhaul at the same time the pump is to be overhauled; and

- There are eight projects which are common to the Campbell site. Based upon a 43% allocation of the cost to Campbell Units 1 and 2 and a 57% cost allocation to Campbell Unit 3, the various 14-month projected bridge period site commons projects include $0.708 million in projected capital expenditures for Campbell Units 1 and 2. A more detailed discussion of these projects will be provided later in this direct testimony in the discussion of Campbell Site Commons projects.

Q. What is the basis for the projected $0.285 million investment in the test year?

A. The projected $0.285 million investment will fund three projects which are common to the Campbell site. This projected amount reflects a 43% allocation of the total amount. A more detailed discussion of these projects will be provided later in this direct testimony in the discussion of Campbell Site Commons projects.

<u>Campbell Unit 3</u>

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for Campbell Unit 3.

A. The Company plans to invest a total of $5.138 million in 14-month projected bridge period and $0.378 million in the projected test year at Campbell Unit 3. The 14-month projected bridge period amount includes $2.437 million in non-environmental expenditures and $2.700 million in environmental expenditures and the projected test year amount includes $0.360 million in non-environmental expenditures and $0.018 million in environmental expenditures. The non-environmental amounts are shown on both Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 8, columns (h) and (j), respectively, and Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 3, columns (b) and (d), respectively, and the environmental amounts are shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 7, line 4, columns (c) and (e), respectively. These capital investments will be facilitated by outages in the spring of both 2023 and 2024. The Campbell Unit 3 outage scheduled for the spring of 2024 is presented on Exhibit A-39 (RTB-1), line 4.

Q. What is the basis for the projected $5.138 million capital expenditure amount for the 14-month projected bridge period?

A. The projected $5.138 million capital expenditure amount will fund regulatory compliance and reliability projects. One of those projects is greater than $1 million and is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, line 1. The basis for this project is described below:

- Campbell Unit 3 – Selective Catalytic Reduction ("SCR") Catalyst Management ($2,302,733). The scope of this project is the ongoing management of the SCR catalyst. The performance of this work will maintain the functionality of an environmental related system by removing old, exhausted layers of catalyst and replacing with new layers of plate type catalyst, thereby maintaining the efficiency of the SCR. This project is being completed for air quality regulation compliance and is not considered avoidable considering the unit retirement on May 31, 2025.

The following projects are less than $1 million each but are important to regulatory compliance and reliability:

- Campbell Unit 3 Complete Mill Overhauls ($552,370). This project will continue the rebuild of the Campbell Unit 3 Coal Mills which began in 2020 at a projected capital expenditure of $0.503 million. Coal mills experience wear and degradation over time, resulting in reduced performance and increased reliability risk. Suboptimal performance negatively impacts combustion and efficiency due to increased particle sizes. This project will begin the periodic rebuild of the coal mills for Campbell Unit 3. The performance of this work will maintain the high level of unit availability necessary to provide customer value. This project is being completed for unit reliability and is not considered avoidable considering the unit retirement on May 31, 2025;

- Campbell Unit 3 AQCS Projects ($225,000). This project will complete various AQCS projects at Campbell Unit 3 during the 14-month projected bridge period, thereby providing continued equipment reliability and regulatory compliance through plant retirement on May 31, 2025. This project is being completed for air quality regulation compliance and is not considered avoidable;

- Campbell Unit 3 CO-O_2 monitor replacement ($223,944). This project began in 2021 and its scope includes the replacement of the existing O_2 monitors. The ability to monitor post-combustion CO does not currently exist on Campbell Unit 3; the existing monitors only measure oxygen. The inability to adequately measure the flue gas results in poor combustion and increased difficulty in efficiently controlling NO_x. The monitor replacements will be completed in the spring 2023 outage; resulting in increased efficiency and improved environmental monitoring and control. This project is being completed for unit reliability and is not considered avoidable considering the unit retirement on May 31, 2025;

- Campbell Fuel Handling/Infrastructure Replacements ($200,000). Due to normal wear, fuel handling equipment requires periodic replacement. Specific equipment will be replaced during the 14-month projected bridge period based on condition. Equipment to be replaced includes conveyor belts, chutes, and other major fuel handling equipment and infrastructure. This project work will result in continued fuel handling reliability through plant retirement on May 31, 2025. This project is being completed for unit reliability and is not considered avoidable considering the plant retirement on May 31, 2025;

- Five additional projects at Campbell Unit 3 totaling $0.695 million support regulatory compliance and reliability, with each project representing $230,000 or less in capital expenditures. These projects include replacement of the electrohydraulic controls fluid purification system, balance of plant equipment replacements, major motor and pump overhauls, emergency diesel generator controls replacement, and house service air compressor replacement; and

- "Site Common" Projects Shared with Campbell Units 1 and 2 ($1,647,239). Projects that affect the entire site are allocated based on the respective size of the units, with Campbell Unit 3 receiving 57% of the expenditures. These projects are discussed below.

Q. Please explain the Site Commons projects.

A. There are eight Site Commons projects in the 14-month projected bridge period with a total dollar amount of $1.647 million subject to allocation as described above. None of these projects are greater than $1 million but the following projects are important to regulatory compliance and reliability:

- Campbell Coal Fleet Fuel Handling Dozer Rebuilds ($537,000). There are Rubber Tire and Track dozers that are used for fueling the plants, pushing coal out to storage, and grooming the coal pile. In order to reliably keep unloading coal and fueling the plants, these dozers routinely need to go through recommended rebuilds to maintain the fleet of dozers in reliable operating conditions. Failure to provide funding for these dozers could result in catastrophic failure of several diesel components in the dozer, which would necessitate the purchase of a new dozer rather than planning for a rebuild. This project is being completed for unit reliability and is not considered avoidable considering the plant retirement on May 31, 2025; and

- Seven additional site common projects at the Campbell site totaling $1.110 million support safety and reliability, with each project representing $335,000 or less in expenditures. These projects include replacement of small pumps and motors, replacement of small valves and instrumentation, and Urea Based Ammonia Supply upgrades.

Q. What is the basis for the projected $0.378 million investment in 2023?

A. The projected $0.378 million investment will fund three projects which are common to the Campbell site. This projected amount reflects a 57% allocation of the total amount, which is $662,918. These projects include fuel handling dust collector bag replacement, dry ash landfill closure, and machine shop replacement. The funding for the machine shop replacement will evaluate and engineer the various alternatives for moving/replacing the existing machine shop at the Campbell site. The machine shop provides timely and cost-effective solutions to parts and equipment needs at the Company's generating facilities.

<u>Covert Plant</u>

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for Covert.

A. The Company plans to invest a total of $829.095 million in the 14-month bridge period and $20.274 million in the test year at the Covert Plant. These capital investments will be facilitated by 19-day outages at Covert Units 1 through 3 in October and November 2024.

Q. Please explain the Company's projected capital investment for the 14-month bridge period ending February 29, 2024 for the Covert Plant.

A. The Company plans to invest a total of $829.095 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 43, column (h).

Q. What is the basis for the projected $829.095 million capital investment in the 14-month projected bridge period?

A. The projected $829.095 million capital investment in the projected bridge period will fund four projects, including the acquisition of the Covert Plant. Three of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 2 through 4. The basis for these three projects is described below:

- Acquisition of the Covert Plant ($815,000,000). The scope of this project is the acquisition of the Covert Plant on June 1, 2023. This acquisition was fully supported and approved in the Company's 2021 IRP PCA in Case No. U-21090. The Covert Plant is a natural gas-fired, combined cycle power generating facility with a nameplate capacity of 1,175 MW. The Covert Plant is comprised of three, independently dispatchable units, each of which are rated for 392 MW. Each unit is comprised of a combustion turbine generator ("CTG"), heat recovery steam generator ("HRSG"), and steam turbine generator ("STG") in a 1X1 combined cycle configuration;

- Covert Plant LTSA ($9,760,795). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an equivalent fired hour ("EFH") basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and

- Covert Plant non-LTSA ($3,942,510). The non-LTSA work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler.

The following project is less than $1 million, but is important to reliability:

- Covert Base Outage Capital ($391,667). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages.

Q. What is the basis for the projected $20.274 million capital investment in the projected test period?

A. The projected $20.274 million capital investment in the projected test period will fund three projects. Two of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 1 and 2. The basis for these projects is described below:

- Covert Plant LTSA ($13,848,216). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an EFH basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and

- Covert Plant non-LTSA ($5,509,565). The non-LTSA work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler.

The following project is less than $1 million, but is important to reliability:

- Covert Base Outage Capital ($916,667). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages.

Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 14-month projected bridge period ending February 29, 2024 or the projected test period ending February 28, 2025, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

Karn Units 3 and 4

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025, for Karn Units 3 and 4.

A. The Company plans to invest $12.446 million in the projected bridge period and $6.542 million in the projected test period, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected $12.446 million capital investment in the 14-month projected bridge period?

A. The projected $12.446 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 5 through 8. The basis for these projects is described below:

- Karn Unit 3 Cooling Tower Internal Structure Replacement ($3,971,429). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;

- Tank Farm Storage Tank Heating Line Replacement ($1,253,571). This project is to replace the condensate piping from the tank farm heating boilers to the "A" storage tank in the Karn Tank Farm. Over the years the piping that supplies heat via hot condensate from the two Johnston tank farm boilers to the storage tank guillotine heaters has degraded due to freeze damage, age, and corrosion. Currently, when supplying heat to the "A" storage tank the Company loses between 10,000-15,000 gallons of city water per day in make-up from the leaks in the system. The two heating lines are encased in a 12" O.D. spiral welded pipe and are uninsulated. Due to the piping being enclosed within the larger diameter pipe, maintenance can be very labor intensive as leaks are difficult to identify. Also, being uninsulated, if the system is not drained properly or continuously run throughout the freezing temperature months, freeze damage is inevitable;

- Karn Units 3 and 4 Sync Wire Replacement ($1,450,000). The scope of this project is the replacement of the existing copper communication cables between the plant and Hampton Substation. The replacement will consist of fiber optic communication cable from Hampton Substation to the plant and the replacement of Karn Units 3 and 4 generating unit line protection relays, pilot wire differential line protection relaying, telemetry, and control communication at Hampton Substation. Telemetry and control include but are not limited to: breaker position indication, breaker control, transfer trip, bus voltage, and current indication. The Karn Units 3 and 4 auto-synchronizing relay is obsolete. This project will provide a modern reliable communication medium between Karn Units 3 and 4 and Hampton Substation, where the generator synchronization breakers reside. This medium will allow for a reliable means of communication between Karn Units 3 and 4 and the Hampton Substation, thereby reducing the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event; potentially causing damage to the generator and turbine, resulting in decreased plant reliability and increased expense; and

- Karn Site Decommissioning ($1,789,545). The scope of this project includes engineering, procurement and construction activities supporting the separation of various utilities/systems in order to isolate Karn Units 3 and 4 from Karn Units 1 and 2 prior to their retirement in May 2023. The capital expenditures are necessary to comply with the Company's approved 2018 and 2021 IRPs. The major scope items included in the projected capital expenditure amounts for construction include PJFF air compressor, deionized water trailers, high pressure (High Pressure)\Low pressure (LP) House Water Service & Firewater Systems, DCS systems modifications, intake channel freeze protection, sump discharge line rerouting, and switchyard work.

The following projects are less than $1 million, but are important to reliability:

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft (“ID”) Fans to Stack ($950,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4. This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance;

- Karn Unit 4 DCS and Simulator upgrade Evergreen ($900,000). This project replaces the Karn Unit 4 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2015 and software upgraded in 2019. This Evergreen will replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades, the controller drops, and rack-mounted servers will be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates;

- Karn Unit 3 DCS & Simulator Evergreen ($540,000). This project replaces the Karn Unit 3 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2019. This Evergreen will only replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of “extended support” and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates;

- BOP Capital tooling/valves/instrumentation ($891,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4; and

- Five additional projects at Karn Units 3 and 4 totaling $0.700 million which support safety, security, and reliability, with each project representing $185,000 or less in capital expenditures. These projects include replacement of Karn

Units 3 and 4 Pneumatic Controllers, Karn Units 3 and 4 fire protection replacement, and Karn Units 3 and 4 fleet cyber security, and Primary and Secondary Air Shroud Drives.

Q. What is the basis for the projected $6.542 million capital investment in the projected test period?

A. The projected $6.542 million capital investment in the projected test period will fund five projects. One of these projects is greater than $1 million and is presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, line 7. The basis for these projects is described below:

- Karn Unit 3 Cooling Tower Internal Structure Replacement ($5,000,000). The scope of this project is the replacement of the structural timbers, remaining stacks, and fan blades. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. The entirety of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031.

The following projects are less than $1 million, but are important to reliability:

- Capital tooling/valves/instrumentation ($791,667). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year;

- Ductwork Expansion Joint Replacement - ID Fans to Stack ($316,667). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance; and

- Two additional projects at Karn Units 3 and 4 totaling $0.433 million which support safety and reliability, with each project representing $383,333 or less in capital expenditures. These projects include fleet cyber security and Primary and Secondary Air Shroud Drives.

Zeeland Plant

Q. Please explain the Company's projected investment for the 14-month projected bridge period ending February 29, 2024 and projected test year ending February 28, 2025 for the Zeeland Plant.

A. The Company plans to invest $37.879 million in the 14-month projected test period and $15.286 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by short outages in the spring and fall of the 14-month projected test period and the projected test year. The Company has an LTSA with GE that covers many reliability issues at the Zeeland Plant.

Q. What is the basis for the projected $37.879 million capital investment in the 14-month projected bridge period?

A. The projected $38.879 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are nine projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 12 through 20. The basis for these projects is described below:

- Zeeland Plant LTSA ($9,520,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland - Purchase of Site Spare Generator Step Up ("GSU") Transformer ($2,883,333). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Unit 3 Field Rewind of Generator Rotor ($1,205,357). This project will be executed in the 2023 major outage. There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as

multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life;

- Zeeland Unit 4 Field Rewind ($1,205,357). This project will be executed in the 2023 major outage. There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life;

- Zeeland Unit 1 GSU Transformer Rewind ($4,604,082). Zeeland Unit 1 GSU is responsible for stepping up the 215MVA output of Unit 1 generator to the grid from 18KV to 345KV. Since Consumers Energy purchased the site, the Unit 1 GSU Transformer has been producing low levels of Acetylene gas internally. Production of Acetylene is normally an indication of a high energy discharge occurring within the oil space. Acetylene was level and stable at 5 PPM until the combustion turbine 1 52G generator breaker grounding event in 2015 where after re-energization it jumped to 7 PPM and gradually rose to 9 PPM by 2018. However, since 2019, the Acetylene value has increased from around 9 PPM to 23 PPM with a rather noticeable departure from trend rates starting in April 2021. The noted increase as of late is a concerning change from the previous relatively flat line trends and it is usually indication of advanced rates of deterioration than previously observed.

  This unit had been operating outside of the recommended Institute of Electrical and Electronics Engineers values of 1-2 PPM historically. Internal inspections were completed in September 2021. The findings by the OEM were significant such that they did not recommend re-energizing the transformer. New GSU procurement is estimated at 24 to 36 months lead time and there was no spare GSU transformer currently known to be available to be used in an emergency. The current unit required a full rewind or other substantial dismantling work scope to repair, requiring it to be removed from service and shipped off site for eight or more months. The OEM and company subject matter experts condemned Unit 1.

This project will refurbish the removed GSU Transformer to ensure that the Zeeland Unit 1 generator can safely and reliably supply power to the grid. In addition, this project procured a leased transformer which was used until needed for the continued operation of Zeeland Unit 5;

- Milestone outage capital to GE – part of LTSA contract ($7,870,000). The milestone payment is made pursuant to the LTSA contract. The milestone payments are required for each gas turbine hot gas path inspection and compensate GE for the new turbine hardware that gets installed during this maintenance evolution;

- Zeeland Plant Combined Cycle 599 and 699 345 kV Breaker Replacement ($1,222,915). The scope of this project is to replace the 599 and 699 circuit breakers with a type which does not exhibit the failure modes exhibited by the existing design. The existing breakers have a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or generator damage;

- Zeeland Plant HRSG Casing Replacement ($2,803,333). The HRSG is designed to recover and recycle heat energy from a gas turbine exhaust. A HRSG produces steam that is used to drive a steam turbine. During recent inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion has been identified in particular sections of the units. This condition creates the risk of the studs, which hold on the insulation and liner panels, breaking loose and liberating both insulation and liner sheets. The insulation then blows downstream and fouls the HRSG tubes, requiring the unit to be shut down and cleaned, then subsequent casing, insulation, and liner repairs. The affected areas of casing need to be cut out and replaced with new casing; and

- Zeeland Plant LTSA supplementals not included in contract ($2,900,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Main Steam Non-return Valve Replacement ($375,000). The scope of this project is to replace both main steam check valves. During inspections in the Fall 2018 outage, cracking was noted on both of the main steam stop-check valve body internals. Cracking is adjacent to a guide rib internal to the valve. With continued plant operation, the cracks are expected to continue to grow, potentially extending through the valve seat, making the valve unable to seal completely. The cracks can also grow to a through-wall crack, resulting in a steam leak. This cracking is a known issue with these types of valves, and is driven by expansion differentials primarily on startup and shutdown. This cracking had initially been noted during a pipe borescope inspection in 2011;

- Replace HP Economizer Level Control Valves ($461,000). The scope of this project is to replace the HP Economizer Level Control Valves for HRSG 3 and 4. The existing valves are oversized for the operating conditions at Zeeland. This condition results in excessive valve throttling resulting in increased wear on the valves and HRSG quenching during low boiler feedwater feed periods resulting in cyclical thermal shock to tubes. These level control valves were originally designed for steam augmentation of gas turbines – but that feature has never been used and will never be used – consequently, the valve is oversized;

- Zeeland Plant Combined Cycle Steam Turbine Building Roof Replacement ($600,000). The scope of this project is to replace the turbine building roof and encapsulate the insulation for the combined cycle Zeeland steam turbine. Insulation from the steam turbine building roof is falling from the ceiling, thereby presenting a possible health hazard and also hazard of becoming a foreign material exclusion issue with plant equipment. Replacement of the roof will ensure safe and reliable operation of the steam turbine, and ensure safety of employees by encapsulating insulation;

- Zeeland Plant Base Outage Capital ($437,972). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

- Fifteen additional projects at the Zeeland Plant totaling $1.790 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $315,000 or less in expenditures. These projects include Zeeland Units 3 and 4 Air Filter Replacement, Install New 4160V Cross Tie, 299 345kV Breaker Replacement, Unit 5 Transformer Level Gauge Replacement, boiler feedwater pump, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $15.286 million capital investment in 2023?

A. The projected $15.286 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the

Zeeland Plant. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 5 and 6. The basis for these projects is described below:

- Zeeland Plant LTSA ($8,160,000). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-site technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help minimize ROR and it will optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and

- Zeeland Site Spare GSU Transformer ($3,916,667). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently 100 weeks and spare units at other facilities typically do not exist. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future. As previously discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent out for rewind.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- GE DCS Evergreen ($500,000). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson Power and Water Cybersecurity Suite ("PWCS") application. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches;

- Zeeland Plant 299 345kV Breaker Replacement ($510,075). The scope of this project is to replace the 299 circuit breaker with a type which does not exhibit the failure modes exhibited by the existing design. The existing breaker has a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or generator damage;

- Site Commons Road Resurfacing ($475,000). The scope of this project is to perform continued resurfacing of site roads. Several roads require widening to ensure safe 2-way vehicle travel (e.g. road behind substation). Roads/driveways on site require continuous maintenance. The objective of the project is to ensure roadways are safe for both vehicle and pedestrian travel;

- GT Turbine Inlet Filters Replacement ($325,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;

- Zeeland Plant Base Outage Capital ($413,916). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during unit outages; and

- Twelve additional projects at the Zeeland Plant totaling $1.002 million support reliability and operations, with each project representing $250,000 or less in expenditures. These projects include ABB DCS Evergreen, MarkVIe controller replacement, boiler feedwater pump overhaul, filter replacement, and small pumps, motors, valve, instrumentation, tools, and equipment.

<u>Jackson Plant</u>

Q. Please explain the Company's projected investment for the 14-month bridge period ending February 29, 2024 and test year ending February 28, 2025 for the Jackson Plant.

A. The Company plans to invest $15.977 million in the 14-month projected bridge period and $11.720 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the fall of 2023 and 2024. The Company has a LTSA with GE to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected $15.977 million capital investment in the 14-month projected bridge period?

A. The projected $15.977 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are three projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 9 through 11. The basis for these projects is described below:

- Jackson Plant LTSA ($9,570,928). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- CTG 7 Replace Turbine Casing ($2,088,234). The scope of this project is the replacement of the turbine casing and bolting that holds the two-part casing together. Industry experience has shown that the casing bolting is susceptible to failing, resulting in catastrophic failure. Based on condition assessments of the turbine casing, the Company will conduct this work during the major outage in 2023; and

- Scanners and Igniters Replacement ($2,020,513). Reliable ignition is critical for the increasing use of on/off cycling and low load operation. As the plant cycles on and off and operates at low load, the duct burners are not used. The HRSG duct burners are utilized when increased MW demand is required. The igniters are used to light off the duct burners. The current scanners and igniters are at end of life. This project would also add solenoids to the assemblies so individual rows of ignitors and duct burners can be isolated for repairs while the other duct burners are in service. This cannot be done in the present configuration as there is no isolation at the igniters.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Extra Work ($428,333). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- LM6000 Beckwith Relay Replacement ($390,914). The scope of this project seeks to replace the LM6000 Generator Protective Relays with direct replacement relay upgrades and install test facilities in a pre-planned fashion. This will protect the generation assets and avoid issues with the obsolescence of the existing equipment. Jackson Units 1 through 6 are currently protected with Beckwith M3420 Relays. These relays protect the generator from internal and external system fault events and are obsolete. The long lead time replacement M-3425A relays have been purchased, and are awaiting installation.

  In addition to being obsolete, the existing relays have limited, or no means for communication, fault analysis, troubleshooting, and event recording following an electric fault event. The current relays also do not have external test facilities for periodic maintenance. Because of this, the relays need to be un-wired to test, and then rewired. This increases maintenance time, as well as exposes the plant to unplanned operations due to human error;

- Base Outage Capital ($320,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Plant Units 1 – 6 Singular Annular Combustor ("SAC") Extended Life Combustor ($189,583). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and

- Nine additional projects at Jackson Plant totaling $0.968 million, with each individual project representing $275,833 or less in expenditures. These projects include NO_x Umbilical Replacements, RO pretreatment system, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

Q. What is the basis for the projected $11.720 million capital investment in the projected test year?

A. The projected $11.720 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 3 and 4. The basis for these projects is described below:

- Jackson Plant LTSA ($8,244,761). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The Jackson Plant is comprised of nine generating units. Units 1 through 6 are GE Model LM6000PC Gas CTG each with a HRSG attached to the exhaust of the Combustion Turbine. Unit 7 is a GE Model Frame 7EA CTG with a HRSG, and Units 8 and 9 are GE STGs powered by the steam created from the 7 HRSGs. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, address service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units; and

- Jackson Plant Units 1 – 6 SAC Extended Life Combustor ($1,338,458). The scope of this project is to remove the G42 combustor and replace it with the new Rich Quench Mixture ("RQM") combustor during hot gas path inspections. Specifically, this project will perform an operational study to operate a RQM combustor in a steam/gas configuration and attempt to achieve 15 ppm NO_x. The study will be to install an RQM combustor on 1 of the 6 LM6000s. If the operational study proves to be successful, an RQM combustor would then be installed on all LM6000 units. There are 7 total, 6 in service and 1 spare.

  The Jackson Plant's LM6000 units currently utilize a G42 Jet-Rad combustor. In recent years, the OEM developed the Rad-Rad (G48) design combustor to increase the longevity of primary and secondary swirlers by improving the materials to prevent or reduce their cracking over time and reduces thermal barrier coating loss on high pressure turbine stage 1 blades. More recently, the RQM combustor has been introduced by GE. The RQM combustor liners improve dilution characteristics by repositioning combustion location and lowering combustion area for lower emissions. The RQM combustor is expected to significantly increase the combustor section life (32,500 hours vs. 25,000 hours). Upgrading the combustor section of each LM6000 to a RQM combustor also has the potential of lowering the NO_x production for each unit, which would result in more full load capability. The LM6000 units currently operate with emissions of 25 PPM NO_x and 40 PPM CO. The 12-month rolling NO_x limit is 95 tons per year, per engine. The 12-month rolling CO limit is 360 tons per year for the site for the six LM6000 units. The 12-month rolling NO_x limit is the limiting factor for the site in regard to running the units near full load capability for the entire year; at times the engines have to be curtailed due to NO_x emission limits.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Supplemental Work ($600,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Base Outage Capital ($300,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

- Thirteen additional projects at Jackson Plant totaling $1.237 million, with each individual project representing $225,000 or less in expenditures. These projects include NO_x Umbilical Replacements, Combustion Turbine Inlet Canister Filter Replacement, 480V Breaker (WavePro) Overhaul, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for the Hydro Units.

A. The Company plans to invest $36.662 million in the 14-month bridge period and $48.897 million in the projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected $36.662 million capital investment in the 14-month projected bridge period?

A. The projected $36.662 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are twelve projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 21 through 32. The basis for these projects is described in the direct testimony of Company witness Monroe.

Q. What is the basis for the projected $48.897 million capital investment in the projected test year?

A. The projected $48.897 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are 13 projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 8 through 20. The basis for these projects is described in the direct testimony of Company witness Monroe.

LPS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for the LPS.

A. The Company plans to invest $13.623 million in the 14-month projected bridge period and $14.137 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 71, columns (h) and (j), respectively. These capital investments will be periodic outages in the spring of 2023 and 2024.

Q. What is the basis for the projected $13.623 million capital investment in the 14-month projected bridge period?

A. The projected $13.623 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 33 through 37. The basis for those projects is described below:

- LPS Oil Water Separator Replacement ($1,162,917). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Powerhouse Roof Wearing Surface and Weather Proofing Replacement ($2,724,054). The scope of this project includes engineering of the demolition, disposal, and replacement of the concrete wearing surface and waterproofing. This project began in 2018 with actual capital expenditure amounts of $0.036, $0.074, $0.095, and $0.230 million for 2018 through 2021, respectively. The 2022 capital expenditure of $2.325 million covered material procurement and installation. This project was delayed due to the project extension for the Ludington Unit 3 upgrade. The LPS powerhouse roof wearing surface and waterproofing has deteriorated and needs to be replaced. The powerhouse roof has only had minor repairs since the plant was originally constructed. Currently, there is water seeping through the roof and leaking onto electrical

equipment. Failure to remedy this situation exposes the electrical equipment to water intrusion and premature failure;

- DCS Control Relay Replacement ($1,347,516). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Replace Lower Penstock Expansion Joint ("LPEJ") Chamber Waterstop ($2,425,493). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of $0.404 million and project implementation began in 2021 and is expected to be completed in 2023.

  In 2021, the engineering was completed, and the design was approved by FERC. In addition, the Unit 3 chamber was stabilized to allow for the Unit 3 waterstop to be replaced without impacting the penstock or impacting the long-term ability to generate from Unit 3. The Unit 3 chamber was stabilized due to the 1.3" of offset due to settlement of the upstream side of the chamber; this impacted the steel expansion joint portion of the penstock. To mitigate the risk of the penstock binding and ensure continued operability of Unit 3, the Unit 3 chamber was stabilized by installing a secant pile shaft and placing grout underneath the chamber to raise it back to its pre-2017 state.

  The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period; and

- Replace Barrier Net Panels ($1,088,614). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Replacement of LPS Depression Air Compressors ("DAC") 1 and 2 ($565,750). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Replace 480V DLCs ($990,030). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Admin Building Addition ($592,377). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- LPS Intake Gate and Gate House Mechanical Replacement ($476,287). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- Governor Replacement ($345,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;
- 19-420 Station Battery Replacement ($265,833). The scope of this project is to replace battery banks 1 and 2. This project will include the installation of new racks and a new battery monitoring system. Ludington relies on two (North American Electric Reliability Corporation ("NERC") compliance) battery banks (1680 amp hours each). Station battery bank 1 provides power to critical control and protection systems for Units 1,2, and 3, while Station battery bank 2 provides power to critical control and protection systems for Units 4, 5, and 6. The banks also provide power to the emergency diesel generator during a black start event. These systems were installed in 2009 and have reached the end of life. The system also is due for a load study to verify its capabilities now that major modifications have been made to systems dependent on the batteries. Failure to maintain battery capacity could risk plant control, and the ability to black start;
- Design and Install Barrier Net - pursuant to the Adaptive Management Process ($358,790). This project is a multi-year project which is being implemented in accordance with the Ludington Relicensing Settlement Agreement, Appendix B (between Consumers Energy, DTE, and various state, federal, and tribal agencies), and the FERC project license for Ludington. This project began in 2020 at a cost of $0.166 million in 2020 and $0.610 million in 2021. This project is projected to continue through 2025, requiring studies and improvements pursuant to the agreement. The objectives of this project are to

optimize barrier net operations and maintenance functions to reduce fish entrainment mortality during pumping and generation, consistent with safety considerations; optimize barrier net design and placement to improve barrier net performance, utilize data from fish community characterization studies to help inform and optimize barrier net design and operations; utilize the results of technology reviews to improve barrier net performance through potential changes in design or deployment; and the implementation of fish entrainment prevention technologies;

- LPS - Draft Tube Water Level Sensing System Replacement ($357,000). Each unit at the LPS has a water column located on D-floor east, elevation 535'. The water column is used to detect water level when the unit is depressing water out of the runner area during pump start or during synchronous condense mode. The entire system is composed of a tubular column, valves and strainers, 4 level electrodes, a sight glass, feedback relays, and a transformer. All the components mentioned above are original to the plant's construction and have been operating for 50 years. Over the course of the plant's operation these components have gradually worn and corroded. Since these components are in a submerged water application with high oxygen content corrosion occurs more quickly. The metallic materials are now at the end of their useable service life. Due to the criticality of the system, there is a risk of over pressurizing the draft tube/depressing the entire draft tube. If this were to occur, damage to the turbine could occur; and

- Twenty-four additional projects at LPS totaling $0.923 million, with each individual project representing $193,958 or less in expenditures. These projects include Intake Battery Bank, Battery Charger and UPS Replacement, Centralized Grease System Replacement, CO^2 fire protection system replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $14.137 million capital investment in the projected test year?

A. The projected $14.137 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 21 through 24. The basis for these projects is described below:

- DCS Control Relay Replacement ($2,500,656). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic input/output modules and new relays where needed. The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the Human Machine Interface ("HMI") graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. This 1970's technology does not provide the diagnostic and troubleshooting capabilities of a modern DCS. Any updates of equipment and systems that are integrated with the unit operation are difficult to automate with the original relay logic, and changes to operating criteria are difficult to implement, test, and verify and are more costly and time-consuming when compared to the capabilities of a modern DCS.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. This may cause units to be unavailable or derated. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end of life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System ("DAS"), Annunciator, Programmable Logic Controller ("PLC"), and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Replace Barrier Net Panels ($1,752,840). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. Ludington has extensive operating experience with these panels, which helps determine when a replacement is required. Similar funding amounts are included for both the projected bridge period and test year;

- Intake Gate and Gate House Mechanical Replacement ($1,118,228). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option; and

- Administration Building Addition ($2,713,585). The scope of this project is to construct a permanent office space for the employees of the Ludington Plant. Currently, many offices at the Ludington Plant are housed in a temporary construction office building. The construction trailers need to be demolished and a permanent office needs to replace them. The temporary office was only intended for use until 2020. The construction of a permanent building addition minimizes the potential for slip trip and falls because employees will no longer need to go outside to travel between the offices in the construction trailers and the Administration Building in the winter.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- LPS Oil Water Separator ("OWS") Replacement ($577,083). The scope of work for this project is to install a separate, parallel train OWS to that of the plant's existing OWS, modify existing support systems (station sump, station sump pumps, & metering devices) to support new OWS, and retrofit the existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one as to not impact unit availability. The project is being performed in order to comply with requirements for effluent discharge during all modes of operation and process upset conditions. The failure to perform this project would likely lead to additional releases in excess of the National Pollutant Discharge Elimination System permit requirements throughout the facility's lifecycle. Although not quantified, cost for these releases could be significant in terms of potential fines, reputational damage, cleanup costs, and other intangibles;

- LPS All Unit Critical Valve & Actuator Replacement ($413,833). The scope of this project is to replace valves, actuators, and associated equipment critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism;

- Governor Replacement ($424,167). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, regularly show signs of wear during routine maintenance;

- Centralized Grease System Replacement ($454,249). The scope of this project is to replace end of service life components such as pumps, distributing blocks, and solenoid valves, and to modernize the control system to a self-diagnostic PLC system. The current electro-pneumatic grease system(s) that service the wicket gate bushings are functionally past their service life and of questionable reliability (original plant equipment);

- Breakwater Tetrapod Project ($682,433). The scope of this project is to install concrete tetrapods on the entire west face of the breakwater. The system will need to be engineered to determine the exact size of the tetrapods to prevent ice from dislodging tetrapods and protect the tailrace from Lake Michigan. The engineering for this project will be done in 2024 with fabrication and installation to be done in 2026.

  The breakwater in the tailrace of the Ludington Plant goes across the west end of the tailrace. The breakwater is made of large rip rap and core stone underneath it. The breakwater protects the plant from Lake Michigan. Over the years, the rip rap has been displaced and dragged out of the breakwater by ice. There are some sections where there is no longer rip rap above water. New shoreline protection needs to be placed to protect the powerhouse from Lake Michigan. The Company repaired as much as possible for $300k in 2019. However, additional funding is necessary to restore the breakwater to its designed dimensions. To address this, concrete tetrapods will be installed on the entire west side of the breakwater as an improvement to protect the plant. The tetrapods interlock together, preventing ice from dragging it out into Lake Michigan. The large concrete tetrapods are designed to endure large wave action and protect the powerhouse from large waves from Lake Michigan;

- 20 kW Main Transformer Bank (“MTB”) Disconnect Replacement ($350,375). This project will install safe and reliable disconnect switches designed for electrical isolation. Currently, the station relies on the removal of physical links and numerous administrative controls to obtain working clearance that could create a hazard if not strictly adhered to. Installation of disconnects with grounding ability would mitigate the potential safety hazards to personnel and eliminate contamination of the ISO Phase Bus. These disconnects will significantly reduce the required administrative controls and exposure to conductors, thus reducing the probability of a safety hazard from human performance or engineering deficits. This would also provide LPS a safe, reliable means of separating units (including the Power Potential Transformer ("PPT")) from the MTB, eliminating the need for and additional PPT disconnect project. Providing quicker means to disconnect and reconnect the units from their MTB, without impacting the adjacent unit, would mitigate almost all negative cash flows realized to isolate a unit from its MTB for the remainder of the site's life. Installing "no load" disconnect and safety ground switches in strategic locations would mitigate almost all O&M labor dollars associated with manual efforts at the links, as well as mitigate the loss of revenue incurred on the non-outage unit affected for the amount of time required to execute these evolutions. This effort will install new equipment, improving safety when isolating the 20 kV system for the remainder of site life;

- Replace 480V DLCs ($851,900). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of $0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance;

- Replace Barrier Net Panels ($374,102). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required. Similar funding amounts are included for both 2022 and 2023; and

- Twenty-four additional projects at Ludington totaling $1.923 million, with each individual project representing $239,317 or less in capital expenditures. These projects include pony motor isolation switch life cycle project, station power transformer life cycle management, replacement of LPS DAC 1 & 2, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Administrative and Other.

A. The Company plans to invest $1.252 million in the 14-month projected bridge period and $0.979 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 3, line 78, columns (h) and (j), respectively.

Q. What is the basis for the projected $1.252 million capital investment in the 14-month projected bridge period for Administrative and Other?

A. The projected $1.252 million capital investment will support several projects during 2022. The basis for these projects is described below:

- Enterprise Project Management Office Transformation—Enterprise Project Management Information System ($437,187). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and Other;

- Generation Operations – Ovation security center replacement evergreen ($300,000). The Generation control systems cyber security tool that is used for control system security is PWCS. This tool is comprised of multiple cyber security products used in the industry today. Because of the quickly changing technology and techniques used by hackers, the cyber security tools require an increased update cycle of two to three years. The Karn site has been using the PWCS tool for 10 years. It was last upgraded in 2017. To support the latest version of Ovation DCS, the PWCS system must be upgraded. This replacement will support the protection of multiple components of the control system across multiple sites including Karn Units 3 and 4, Campbell, Jackson, Zeeland, and Ludington. The tools included are:

    - Anti-Virus
    - Malware Prevention with Application Control
    - Patch Management
    - Device Control
    - Rogue System Detection
    - System Backup and Recovery

- Security Incident and Event Manager
- Change Management; and

- Laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management ($515,000).

Q. What is the basis for the projected $0.979 million capital investment in the projected test year?

A. The projected $0.979 million capital investment in the projected test year will fund several projects. The basis for these projects is described below:

- Laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management ($645,000); and

- Enterprise Project Management Office Transformation—Enterprise Project Management Information System ($333,963). The scope of this project is to provide for the continuing upgrade of the Company's project management tools and methods, allowing better tracking and more effective project implementation. The additional capital will continue to support continuing enhancements of the project management information system ("PMIS") which was chosen by the Company after proof of concept on the Ludington overhaul project as well as a request for proposal process which evaluated eight comparable products. The benefits of implementing the PMIS (Primavera Unifier ("Unifier")) include resolution of an external audit finding, increased project management efficiency, and speed of delivery. Unifier provides the tools, technologies, and processes for project management to control the risks associated with delivering a large portfolio of capital projects valued well into the billions of dollars. The project spending will include configuration management as well as quarterly Unifier enhancements based upon ongoing feedback and recommendations from the users of Unifier. The projected capital expenditures in both the 14-month bridge period and the test year represent the electric share of the total projected capital expenditures.

COMPANY-OWNED SOLAR RESOURCES

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 29, 2024 and the projected test year ending February 28, 2025 for Company-owned solar resources.

A. The Company plans to invest $417.180 million in the 14-month projected bridge period and $269.457 million in the projected test year in Company-owned solar resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.1, page 2, line 50, columns (h) and (j), respectively.

Q. What is the basis for the projected $417.180 million capital investment in the 14-month projected bridge period?

A. The projected $417.180 million capital investment in the 14-month projected bridge period will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Mustang Mile, Washtenaw, and Muskegon Solar, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 38 through 40. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected $269.457 million capital investment in the projected test year?

A. The projected $269.457 million capital investment in the projected test year will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Mustang Mile, Washtenaw, and Muskegon Solar, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, lines 25 through 27. The basis for those projects is described in the direct testimony of Company witness Clark.

Q. Are you supporting any other projected capital expenditures for generation related projects in the test year ending February 28, 2025?

A. Yes. I am also supporting an Information Technology ("IT") project, Generation Operations Digital Work Management. The test year projected capital expenditure amount is $1.379 million, and the test year projected O&M expense amount is $0.110 million. These amounts are reflected in the exhibits of Company witness Heather M. Weller. The scope of this project is to provide durable mobile devices, software, and digital forms for Electric Generation at LPS, wind parks, and hydro facilities.

Q. What are the benefits of this technology project?

A. This project will provide faster retrieval and updates of procedures, equipment statistics, work order data, and time entry. The current work management process for Electric Generation at the wind parks, hydro facilities, and LPS is cumbersome and largely paper based outside of desktop kiosks; resulting in process waste, re-work, and human error. This project provides benefits through: (1) increased productivity by reducing the need to return to the desktop kiosk for updates; (2) improved quality through increased accuracy of updates completed at the time and place of the work; and (3) improved safety through real-time information used at work sites rather than printed procedures or drawings.

Q. What is the specific scope of the project?

A. The specific scope of the project includes the initial roll out for Electric Generation at LPS, wind parks, and hydro facilities, which would include mobile devices, software, and enhanced wireless connection.

Q. Did the Company consider alternatives for this project?

A. Yes. The alternatives considered include: (1) Utilize an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost; (2) Continue the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error; (3) Customize the existing electronic Shift Operations Management System ("eSOMS") mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support; (4) Utilize the existing Service Suite solution currently deployed for Gas and Electric Distribution in combination with digital forms. The combined Service Suite and digital form solution is the preferred option because it is a proven solution at the Company and provides the mobility and digital benefits at a lower cost.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark and Monroe provide additional discussion in their direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-41 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-41 (RTB-4), page 1, identifies the actual 2022 through 12 Months Ending February 28, 2025 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2022 Generation O&M expense as $150,030,678;
- Column (c) identifies the 14-Month Projected Bridge Period Generation O&M expense as $172,465,337; and

- Column (d) identifies the Projected Test Year Generation O&M expense as $164,251,928.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects future maintenance needs of each unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – "Base," "Environmental Operations," "Major Maintenance," and "Retention and Separation."

Q. What are Base O&M expenses?

A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company's generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles;

(2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and grounds maintenance.

Q. Please explain how the 2022 Actual O&M expenses were developed.

A. The 2022 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 14-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the projected bridge period ending February 29, 2024, and projected test year ending February 28, 2025 shown on Exhibit A-41 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2022 through the projected test year demonstrates average annual increases of 4.3%. As discussed later in this direct testimony, this average annual increase includes an adjustment related to the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. Exhibit A-41 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-41 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Karn and Campbell site. These expenses are required for safe and reliable operation of Karn Units 1 and 2 through May 2023 retirement and Campbell Units 1, 2, and 3 through May 2025 retirement.

Q. Please explain Exhibit A-41 (RTB-4), page 2.

A. Exhibit A-41 (RTB-4), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or contract rate to historical O&M expense. Column (b) presents the historical O&M expense. Column (c) presents the amount of the historical O&M amount to which an inflation rate or contract rate applies. Columns (e) and (g) present the amounts to which an inflation rate or contract rate were applied for each period, respectively. Columns (d), (f), and (h) present contract and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-41 (RTB-4), page 2.

A. The historical labor on line 1, column (b) reflects a combination of both Operating Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of 3.9%, 2.2%, and 2.1% were applied to labor on line 1, material on line 2, contractor on line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d), (f), and (h).

Q. Please discuss how the adjustments on Exhibit A-41 (RTB-4), page 2, column (i) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test period projected O&M expense amount of $164.252 million reflects that evaluation. Within the test period projected amount of $164.252 million, there is one adjustment that results in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustment that is reflected in the test year projected amount of $164.252 million.

A. As previously discussed, the Settlement Agreement reached in the Company's 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. As a result of the retirement of Campbell Units 1, 2, and 3, the Company's projected test year O&M projections are $7.921 million ($4.687 million when considering inflation) higher than that recorded in the historical test year. This increase fully explains the $4.383 million adjustment reflected on Exhibit A-41 (RTB-4), page 2, column (i), line 1.

Q. Please explain the reason for the increase in O&M for Campbell Units 1, 2, and 3.

A. The actual O&M expense for Campbell Units 1, 2, and 3 in 2022 was $49.344 million as compared to the projected O&M expense for Campbell Units 1, 2, and 3 in the test year of $57.267 million. This increase is primarily a direct result of accounting for some of the projected test year projects as O&M expense versus capital expenditures. Specifically, a number of the projected test year projects were previously recorded as capital expenditures and will now be recorded as O&M expense due to the May 31, 2025 retirement of Campbell Units 1, 2, and 3.

Q. How has this accounting change impacted the capital expenditures for Campbell Units 1, 2, and 3?

A. This change in accounting has resulted in a $11.371 million reduction in capital expenditures for Campbell Units 1, 2, and 3 from 2022 to the projected test year. Specifically, 2022 actual capital expenditures for Campbell Units 1, 2, and 3 were

$12.002 million as compared to the projected test year capital expenditures of $0.631 million.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the operations of the Company's AQCS. As Federal and State emissions standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation. Now that the Company has experienced multiple calendar years of operation, the Company anticipates these expenses to remain relatively consistent going forward. However, because the cost to operate and maintain these critical pieces of equipment is directly related to the operation of the coal-fired power plants they support, yearly variances in the total Environmental Operations expense should be expected based on the operation of the coal plants in a given year.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending February 29, 2024 and test year ending February 28, 2025 were calculated.

A. Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. The operations component is primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. 2022 was the sixth full year of operations of the environmental equipment at both Campbell and Karn, and the Company now has robust historical data to use in projecting these expenses. However, as reflected on Exhibit A-41 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2022 historical expense of $10.802 million to the projected test year expense of $5.860 million reflects a cost reduction of $4.942 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31, 2023.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the Major Maintenance O&M expenses for the projected bridge period ending February 29, 2024 and test year ending February 28, 2025 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

Q. Please identify the 2023 test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $31.976 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-41 (RTB-4), page 1, line 4, column (d). Test year Major Maintenance expense by generating unit is presented on Exhibit A-41 (RTB-4), page 3, column (d).

Q. Why is Consumers Energy spending $31.976 million in Total Major Maintenance O&M expense during the projected test year ending February 28, 2025?

A. The Company is spending the majority of its Total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed, thereby minimizing damage that could result in catastrophic failure.

Q. Are Major Maintenance expenses relatively consistent from year to year?

A. No. Although the Company attempts to plan for controlled and consistent levels of Major Maintenance, because Major Maintenance outages occur relatively infrequently, for an individual unit, it is very possible to have significant year-by-year variations in the number, duration, and magnitude of the required Major Maintenance work. Other factors such as unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

Q. Is it possible that changes to the Company's forecasted Major Maintenance plan could occur?

A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. The Company attempts to make the best decision in balancing the cost and risks associated with the operation of the equipment and attempts to minimize the cost to customers. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability considerations can affect the actual timing of an outage and maintenance spending.

Q. Do Major Maintenance costs vary by individual generating unit(s)?

A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal pulverizers (785 MW) would be considerably larger in scope and cost than Major Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same site.

Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch of generating units in its generation portfolio?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. What are the categories of Major Maintenance?

A. Major Maintenance is broken into two categories—outage and non-outage.

Q. Please describe what is included in the outage major maintenance O&M expense.

A. Outage major maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for boiler and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are needed to control the unit output. During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

Q. Please describe the work completed in a boiler inspection.

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

Q. Please describe the work completed in a turbine inspection.

A. Turbine inspections consist of disassembling, inspecting, and cleaning the different components of the turbine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Because of the extreme conditions under which these units operate, the demand for uninterrupted power, and dangers associated with operating these large pieces of equipment, industry standards recommend that inspections be completed every seven years.

Q. Please define non-outage maintenance.

A. Non-outage maintenance O&M costs typically do not require the generating unit be removed from service, but they are still critical to the operation of the unit. An example of non-outage maintenance is Mill/Pulverizer maintenance.

<u>Campbell Units 1 and 2 Major Maintenance</u>

Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 2, column (d), Campbell Units 1 and 2 Major Maintenance expense is forecasted to be $1.782 million in the projected test year ending February 28, 2025, and includes:

- Campbell Units 1 and 2 Periodic Outage Major Maintenance ($533,333). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;

- Campbell Unit 1 Pulverizer Maintenance ($433,333). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment ($301,528). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Five additional Campbell Units 1 and 2 Major Maintenance projects totaling $183,333, with each individual project representing $125,000 or less in expenses. Projects include Boiler Testing (mercury and air toxics standards Compliance and Burner Tuning), deaerator and its storage tank ("DAST") mid-cycle inspection, HEPS, and boiler safety programs FAC inspections; and

- Six Site Common Major Maintenance projects totaling $768,932 which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling $330,641 and Campbell Unit 3 receives a 57% allocation or $438,291. These projects, all of which represent $183,333 or less in expense, include groundwater and corrective action monitoring, dry ash landfill engineering support, fuel handling chute liner repairs, deepwater intake screen inspection, and remedial action plan system O&M.

<u>Campbell Unit 3 Major Maintenance</u>

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 3, column (d), Campbell Unit 3 Major Maintenance expense is forecasted to be $2.229 million in the test year and includes:

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment ($375,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 3 Periodic Outage Major Maintenance ($491,608). The scope of this project is to perform boiler, turbine, and BOP maintenance activities during scheduled periodic outages during the project test year. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance;

- Campbell Unit 3 Boiler Critical Maintenance ($416,667). The scope of this project is to perform any necessary boiler related repairs during the projected test year;

- Two additional projects for Campbell Unit 3 totaling $452,671 in expenses, with each individual project representing $336,033 or less in expenses. These projects include critical motor major maintenance and spray dryer absorber operations and maintenance; and

- Four Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling $438,291.

<u>Karn Units 1 and 2 Major Maintenance</u>

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 4, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be $0.223 million in the projected test year ending February 28, 2025. This forecasted expense for the projected test year ending February 28, 2025 includes vegetation removal, lined impoundment expense, and groundwater-surface water ("GSI") treatment system. The GSI treatment system is a Site Commons project whose expense is shared with Karn Units 3 and 4.

<u>Covert Plant Major Maintenance</u>

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 9, column (d), the Covert Plant Major Maintenance expense is forecasted to be $6.025 million in the projected test year ending February 28, 2025, and includes:

- Covert Plant LTSA Major Maintenance ($3,462,054). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The CTGs are a Mitsubishi model M501G1-Kai, the HRSGs are a Deltak model, and the STGs are Mitsubishi. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an EFH basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant Non-LTSA Major Maintenance ($600,000). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;

- Covert Plant Capacity Factor Used For Water and Chemicals ($1,300,000). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Covert Plant Base Outage Funding – Boiler plant equipment ($500,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

- Covert Plant HEPS/FAC/DAST Inspections ($163,333). This project will include the performance of regulatory required HEPS, FAC, and DAST inspections.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 5, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be $2.017 million in the projected test year ending February 28, 2025, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance ($425,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;

- Karn Unit 3 Cooling Tower Repairs ($416,667). The scope of this project is to repair as much of the rotted and broken structure as possible and utilize the capital portion of the project to replace fans and other capital items; and

- Fourteen additional projects for Karn Units 3 and 4 totaling $1,123,333 in expenses, with each individual project representing $140,000 or less in expenses. These projects include critical motor major maintenance and spray dryer absorber operations and maintenance.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 7, column (d), Zeeland Plant Major Maintenance expense is forecasted to be $4.658 million in the projected test year ending February 28, 2025, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract ($1,925,000). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals ($1,208,333). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Base Outage — Boiler Plant Equipment ($600,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and

- Fourteen additional projects totaling $924,334 in expenses, with each individual project representing $208,333 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, large oil-filled transformer maintenance, breaker maintenance, and NERC-required relay testing.

<u>Jackson Plant Major Maintenance</u>

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 8, column (d), Jackson Plant Major Maintenance expense is forecasted to be $3.061 million in the projected test year ending February 28, 2025. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals ($1,400,000). This item provides for the city water used by the Jackson Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Non-LTSA Turbine and jet engine repairs ($400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;

- Jackson Plant LTSA — Running Maintenance Contract ($250,000). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Jackson Plant Base Outage - Boiler plant equipment ($250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and

- Eleven additional projects totaling $760,550 with each individual project representing $184,167 or less in expenses. These include HEPS, FAC, pre-Filter replacement, high voltage maintenance and NERC testing, and filter house roof maintenance.

LPS Major Maintenance

Q. Please describe LPS Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-XX (RTB-4), page 3, line 10, column (d), LPS Major Maintenance expense is forecasted to be $4.422 million in the projected test year ending February 28, 2025, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal ($2,040,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;

- Nine Year Unit Mechanical Interval Inspection & Replacement ($570,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the 6 units as well as up front planning and procurement funding in the first year;

- Reservoir remediation ($450,000). This is FERC required and related to dam safety to ensure the Company maintains the integrity of the Ludington pond;

- LPS Generator Circuit Breaker (“GCB”) Pumping pole maintenance ($200,000). The scope of this project is to perform maintenance on the Ludington GCBs (Pumping); and

- Twenty additional projects totaling $1,161,775, with each individual project representing less than $161,000 in expenses. These include LPS Units 4 and 6 Trash Rack Uplift Study, thrust bearing pad inspection and characterization, periodic outage inspections and non-destructive examination, lube oil room repair, Polychlorinated Biphenyl removal and disposal, and powerhouse slope terrace drain cleanout.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 11, column (d), Hydro Major Maintenance expense is forecasted to be $6.298 million in the projected test year ending February 28, 2025, and includes:

- Hydro License Initiatives ($1,816,667). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;

- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections ($1,117,833). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years (FERC Part 12 regulations are discussed in Mr. Monroe's direct testimony). A similar level of expense is budgeted annually from 2023 through 2025;

- Foote Downstream Concrete Repairs ($916,667). The scope of this project is to perform correct deficiencies identified in the 2018 Part 12D independent consultant and third-party condition assessment consultant noted multiple deficiencies in their onsite inspections in 2018. These repairs will include repair deteriorated concrete within the tumble bay, perform concrete repairs on the downstream side of the spillway near the openings to the hollow chambers and possibly fill the chambers with concrete, seal the joints between the concrete slabs on the downstream spillway apron to provide protection against scour and undermining of the concrete slabs, and repair/fill the spillway chamber;

- Rogers Right and Left Spillway Wall Repairs ($416,667). The scope of this project is to perform necessary repairs to the right and left spillway walls. Damage to the right and left walls was sustained during the 2014 flood;

- Alcona Unit 1 concrete repairs ($250,000). The scope of this project is to investigate the concrete and grout defects and perform repairs. During the Unit 1 2020 outage, concrete cracking was noted above the wicket gate casing but below the head cover. Separation of previously placed grout was also noted in the same area. Minor seepage was noted through one of the cracks. There was no seepage noted through any of the previously grouted areas. Repairing the concrete deck support would decrease the probability of water damaging the 7200-volt electrical system and other mechanical and electrical systems in the vicinity;

- Hydro Powerhouse structure Assessments ($225,000). The scope of this project is to complete a desk top study supplemented with site visits to all 13 river Hydros. Document current high-level conditions of the powerhouse structure, consider high level conceptual repair alternatives, replacement, or removal alternatives. Develop a short- and long-term strategy for buildings that are 85 to 110 years old;

- Hydro Concrete Repairs ($232,950). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 river hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and

- Twenty-six additional projects totaling $1,321,917 with each individual project representing $175,000 or less in expenses. These projects include Hodenpyl and Tippy Geotech and stability analysis, Tippy Tumble Bay rehabilitation, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

<u>Solar Major Maintenance</u>

Q. Please describe Solar Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 12, column (d), Solar Major Maintenance expense is forecasted to be $0.778 million in the projected test year ending February 28, 2025 and includes three projects, all to provide IT support for the Mustang Mile, Muskegon Solar, and Washtenaw Solar IRP solicitation projects. For each of the solar sites, the major maintenance funding includes plant setup in SAP, and payment of the OSISoft PI Historian and Bazefield SCADA overlay license fees.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 13, column (d), Admin and Other Major Maintenance expense is forecasted to be $0.150 million in the projected test year ending February 28, 2025 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb ("Cobb"), J.C. Weadock ("Weadock"), and J.R. Whiting ("Whiting") units) Major Maintenance expenses for the projected test year ending February 28, 2025.

A. As shown on Exhibit A-41 (RTB-4), page 3, line 6, column (d), Classic 7 Major Maintenance expense is forecasted to be $0.334 million in the projected test year ending February 28, 2025.

Q. Why is Consumers Energy projecting to spend $0.334 million in Major Maintenance on the Classic 7 units in the projected test year ending February 28, 2025?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, Weadock groundwater and corrective action monitoring, and Whiting ash pond post-closure care.

KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan is a people strategy that the Company has implemented to ensure that it can retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold and dark time period following retirement. The cold and dark condition refers to the period following plant retirement and prior to plant decommissioning. During this period, limited environmental remediation and perhaps partial demolition is performed. The facility may be physically secured with fencing and other measures to prevent vandalism or theft so as to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

Q. What is the purpose of the retention component of the Company's plan?

A. The Company has a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 will become increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the units both safely and reliably. The retention component utilizes the best practices that the Company employed in retiring the Classic 7.

Q. What is the purpose of the separation component of the Company's plan?

A. When Karn Units 1 and 2 are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Karn retention and separation plan?

A. The Karn retention and separation plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Karn retention and separation plan.

A. The retention benefits associated with the Karn retention and separation plan include three payment components: a signing incentive, annual incentives, and a final retention incentive.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in October 2019. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Karn until October 31, 2020 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2020, the employee forfeited the signing incentive.

Employees receive an annual incentive which graduates from 20% to 30% of their base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and rendering service for the next 12 months. The employee must stay at Karn until October 31 of the following year to receive the payment; if the employee stays until that date, the incentive will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the next year, the employee forfeits the annual incentive. Eligible employees received their first annual incentive payment in November 2020, a second payment in November 2021, and a third payment in November 2022.

Employees receive a final retention incentive equal to 60% of their base pay on or about July 1, 2023, if the employee is still at Karn. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

Q. Please describe the severance benefits associated with the Karn retention and separation plan.

A. The severance benefits associated with the Karn retention and separation plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Karn Units 1 and 2?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did in 2016. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees.

Q. Please explain the relevant details of the collective bargaining agreement for OM&C employees.

A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and the Generation Operations Coal Closing Agreement provide that employees will be placed in either a corresponding position, or if none exists, in a vacant position he/she is qualified to perform within 60 miles of his/her current headquarters. Per Article XVII of the collective bargaining agreement, employees who are released due to lack of work, and are not placed as described above, are provided a separation allowance consisting of straight time pay for five regular workdays for each year of continuous service with the Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2, as described above, it is anticipated that some employees will be eligible for a separation allowance.

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date. This incentive program is the same program that is currently in place for employees at the Karn site.

Q. What is the purpose of the retention component of the Company's plan?

A. For similar reasons described in the Karn retention plan, the Company has a strong interest in keeping qualified employees working at the Campbell site through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. Similar to the situation at the Karn site, it will be increasingly difficult to hire new employees at the Campbell site given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the three units both safely and reliably.

Q. What is the purpose of the separation component of the Company's plan?

A. When the Campbell units are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Campbell retention plan?

A. Similar to the Karn retention and separation plan, the Campbell retention plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Campbell retention plan.

A. The retention benefits associated with the Campbell retention plan include three payment components: a signing incentive, periodic incentives, and a final retention incentive. The timeline for retention benefits reflects approval of the Settlement Agreement in the Company's 2021 IRP in June 2022.

Employees receive a signing incentive equal to 15% of their base pay if they signed a retention agreement in July 2022. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee must stay at Campbell until October 31, 2022 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2022, the employee forfeited the signing incentive.

Employees receive a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell and rendering service for a certain period. Specifically, for service provided July 2022 through October 2022, employees received 20% of their base pay. For service provided November 2022 through October 2023, employees will receive 25% of base pay. For service provided November 2023 through October 2024, employees will receive 30% of base pay. The employee must stay at Campbell until October 31 of the given year to receive the payment; if the employee stays until that date, the incentive was/will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the given year, the employee forfeits the annual incentive.

Employees receive a final retention incentive equal to 60% of their base pay on or about October 31, 2025, if the employee is still at Campbell. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the 12 months prior to the payment.

Q. Please describe the severance benefits associated with the Campbell retention plan.

A. The severance benefits associated with the Campbell retention plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Campbell Units 1, 2, and 3?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (7 within 60 miles of the Campbell site) to which employees can relocate, than it did in 2016. In addition, the Company will also have retired at least two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees, as previously discussed for the Karn retention and separation plan.

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-41 (RTB-4), page 1, line 5, the Company incurred actual expense of $2.339 million in 2022, and is projecting expense of $14.917 million in the 14-month projected bridge period, and $18.220 million in the projected test year. The actual 2022 expense of $2.339 million is based upon expense of $2.339 million for Karn. The 14-month projected bridge period expense of $14.917 million is based upon expense of $4.704 million for Karn and $10.213 million for Campbell. The projected test year expense of $18.220 million is based upon expense of $4.145 million for Karn and $14.074 million for Campbell.

Q. Is the Company requesting O&M recovery of the $18.220 million projected amount for the projected test year?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in electric rate case, Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2022 through the projected test year ending February 28, 2025 are not included in the Total O&M amounts on Exhibit A-41 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Aponte supports regulatory asset treatment of these expenses in her direct testimony.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
Page: 1 of 10
Witness: RTBlumenstock
Date: May 2023

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures
($000)

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2022	(c) Projected Bridge Period 12 Mos Ended 12/31/2023	(d) Projected Bridge Period 2 Mos Ending 2/29/2024	(e) Projected Bridge Period 14 Mos Ending 2/29/2024	(f) Projected Test Year 12 Mos Ending 2/28/2025
1	Steam Power Generation					
2	Environmental	$ 1,108	$ 3,024	$ 6	$ 3,031	$ 48
3	Routine and Small CapEx	$ 8,901	$ 15,016	$ 1,260	$ 16,276	$ 7,173
4	Total Steam Production	$ 10,009	$ 18,041	$ 1,266	$ 19,307	$ 7,221
5	Hydraulic Power Generation					
6	Routine and Small CapEx	$ 26,545	$ 28,372	$ 8,289	$ 36,662	$ 49,897
7	Total hydraulic production	$ 26,545	$ 28,372	$ 8,289	$ 36,662	$ 49,897
8	Pumped Storage Generation					
9	Ludington Overhaul	$ 8,796	$ -	$ -	$ -	$ -
10	Routine and Small CapEx	$ 2,962	$ 11,558	$ 2,065	$ 13,623	$ 14,137
11	Total Pumped Storage Generation	$ 11,757	$ 11,558	$ 2,065	$ 13,623	$ 14,137
12	Other Production Plant					
13	Routine and Small CapEx	$ 93,060	$ 1,231,991	$ 69,392	$ 1,301,383	$ 317,717
14	Total Other Production Plant	$ 93,060	$ 1,231,991	$ 69,392	$ 1,301,383	$ 317,717
15	SubTotal	$ 141,372	$ 1,289,962	$ 81,012	$ 1,370,974	$ 388,972
16	Less Contingency	$ -	$ 590	$ 217	$ 807	$ 1,083
17	Grand Total	$ 141,372	$ 1,289,372	$ 80,795	$ 1,370,168	$ 387,888

Line No.	(a)	(b) Projected 2 Mos Ending 2/28/2023	(c) Projected 12 Mos Ending 2/29/2024	(d) Projected 12 Mos Ending 2/28/2025	(e) Projected 26 Mos Ending 2/28/2025
1	Steam Power Generation				
2	Environmental	$ -	$ 3,031	$ 48	$ 3,079
3	Routine and Small CapEx	$ 4,677	$ 428,780	$ 276,630	$ 710,087
4	Total Steam Production	$ 4,677	$ 431,811	$ 276,679	$ 713,166
5	Hydraulic Power Generation				
6	Routine and Small CapEx	$ 2,005	$ 34,657	$ 49,897	$ 86,558
7	Total hydraulic production	$ 2,005	$ 34,657	$ 49,897	$ 86,558
8	Pumped Storage Generation				
9	Ludington Overhaul				$ -
10	Routine and Small CapEx	$ 1,151	$ 12,472	$ 14,137	$ 27,759
11	Total Pumped Storage Generation	$ 1,151	$ 12,472	$ 14,137	$ 27,759
12	Other Production Plant				
13	Routine and Small CapEx	$ 6,499	$ 877,703	$ 48,260	$ 932,462
14	Total Other Production Plant	$ 6,499	$ 877,703	$ 48,260	$ 932,462
15	SubTotal	$ 14,332	$ 1,356,642	$ 388,972	$ 1,759,946
16	Less Contingency	$ 77	$ 730	$ 1,083	$ 1,890
17	Grand Total	$ 14,256	$ 1,355,912	$ 387,888	$ 1,758,056

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21389
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Date: May 2023

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures

Line No.	Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Projected Bridge Year		**Projected Bridge Period**						**Projected Test Year**	
		12 Months Ended 12/31/2022		**12 Months Ending 12/31/2023**		**2 Months Ending 2/29/2024**		**14 Months Ending 2/29/2024**		**12 Months Ending 2/28/2025**	
1	**JHCampbell 1&2**	**$ 4,067**		**$ 1,379**		**$ 14**		**$ 1,393**		**$ 272**	
2	Contractor		$ 1,825		$ 902		$ 11		$ 913		$ 211
3	Labor		$ 642		$ -		$ -		$ -		$ -
4	Materials		$ 546		$ 311		$ -		$ 311		$ -
5	Business Expenses		$ 2		$ 165		$ 3		$ 168		$ 61
6	Contingency		$ -				$ -		$ -		$ -
7	Other (Loadings, Chargebacks)		$ 1,052				$ -		$ -		$ -
8	**JHCampbell 3**	**$ 7,935**		**$ 2,418**		**$ 19**		**$ 2,437**		**$ 360**	
9	Contractor		$ 3,568		$ 1,655		$ 15		$ 1,671		$ 279
10	Labor		$ 1,301		$ 60		$ -		$ 60		$ -
11	Materials		$ 1,538		$ 523		$ -		$ 523		$ -
12	Business Expenses		$ 7		$ 180		$ 4		$ 184		$ 81
13	Contingency				$ -		$ -		$ -		$ -
14	Other (Loadings, Chargebacks)		$ 1,521		$ -		$ -		$ -		$ -
15	**DEKarn 1&2**	**$ (3,312)**		**$ -**		**$ -**		**$ -**		**$ -**	
16	Contractor		$ (1,680)		$ -		$ -		$ -		$ -
17	Labor		$ (460)		$ -		$ -		$ -		$ -
18	Materials		$ (291)		$ -		$ -		$ -		$ -
19	Business Expenses		$ (2)		$ -		$ -		$ -		$ -
20	Contingency				$ -		$ -		$ -		$ -
21	Other (Loadings, Chargebacks)		$ (880)		$ -		$ -		$ -		$ -
22	**DEKarn 3&4**	**$ 331**		**$ 11,220**		**$ 1,227**		**$ 12,446**		**$ 6,542**	
23	Contractor		$ 292		$ 8,245		$ 1,105		$ 9,350		$ 5,882
24	Labor		$ (115)		$ 157		$ 8		$ 165		$ 41
25	Materials		$ 69		$ 826		$ -		$ 826		$ -
26	Business Expenses		$ 0		$ 1,992		$ 88		$ 2,080		$ 494
27	Contingency				$ -		$ 25		$ 25		$ 125
28	Other (Loadings, Chargebacks)		$ 85		$ -		$ -		$ -		$ -
29	**Zeeland**	**$ 21,590**		**$ 35,256**		**$ 2,622**		**$ 37,879**		**$ 15,286**	
30	Contractor		$ 15,391		$ 31,551		$ 2,298		$ 33,848		$ 13,561
31	Labor		$ 864		$ 344		$ 10		$ 353		$ 48
32	Materials		$ 1,343		$ 175		$ 52		$ 227		$ 258
33	Business Expenses		$ 15		$ 3,152		$ 214		$ 3,365		$ 1,169
34	Contingency				$ 35		$ 50		$ 85		$ 250
35	Other (Loadings, Chargebacks)		$ 3,977				$ -		$ -		$ -
36	**Jackson Generating Station**	**$ 32,540**		**$ 14,062**		**$ 1,915**		**$ 15,977**		**$ 11,720**	
37	Contractor		$ 22,830		$ 12,477		$ 1,750		$ 14,226		$ 10,721
38	Labor		$ 1,122		$ 46		$ 5		$ 51		$ 25
39	Materials		$ 1,686		$ 75		$ 49		$ 124		$ 263
40	Business Expenses		$ 42		$ 1,404		$ 111		$ 1,515		$ 711
41	Contingency				$ 60		$ -		$ 60		$ -
42	Other (Loadings, Chargebacks)		$ 6,860		$ -		$ -		$ -		$ -
43	**Covert**	**$ -**		**$ 825,714**		**$ 3,381**		**$ 829,095**		**$ 20,274**	
44	Contractor		$ -		$ 9,765		$ 3,381		$ 13,146		$ 20,274
45	Labor		$ -		$ -		$ -		$ -		$ -
46	Materials		$ -		$ -		$ -		$ -		$ -
47	Business Expenses		$ -		$ 815,949		$ -		$ 815,949		$ -
48	Contingency		$ -		$ -		$ -		$ -		$ -
49	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
50	**Solar**	**$ 30,487**		**$ 355,715**		**$ 61,465**		**$ 417,180**		**$ 269,457**	
51	Contractor		$ 24,534		$ 40,899		$ 15,801		$ 56,701		$ 75,238
52	Labor		$ 1,225		$ -		$ -		$ -		$ -
53	Materials		$ 3,172		$ -		$ -		$ -		$ -
54	Business Expenses		$ 63		$ 41,403		$ 7,969		$ 49,372		$ 18,849
55	Contingency				$ -		$ -		$ -		$ -
56	Other (Loadings, Chargebacks)		$ 1,493		$ 273,413		$ 37,694		$ 311,107		$ 175,371

MICHIGAN PUBLIC SERVICE COMMISSION **Schedule: B-5.1**

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Case No.: U-21389
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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Projected Bridge Year		Projected Bridge Period						Projected Test Year	
Line No.	Description	12 Months Ended 12/31/2022		12 Months Ending 12/31/2023		2 Months Ending 2/29/2024		14 Months Ending 2/29/2024		12 Mos Ending 2/28/2025	
57	**Classic 7**	**(120)**		**-**		**-**					
58	Contractor		(68)		-		-		-		-
59	Labor		(17)		-		-		-		-
60	Materials				-		-		-		-
61	Business Expenses				-		-		-		-
62	Contingency				-		-		-		-
63	Other (Loadings, Chargebacks)		(34)		-		-		-		-
64	**Hydros**	**26,545**		**28,372**		**8,289**		**36,662**		**49,897**	
65	Contractor		16,457		22,594		6,569		29,163		39,612
66	Labor		3,043		37		15		52		92
67	Materials		1,972		-		-		-		-
68	Business Expenses		168		5,360		1,563		6,923		9,484
69	Contingency				382		142		524		708
70	Other (Loadings, Chargebacks)		4,905		-		-		-		-
71	**Ludington**	**11,757**		**11,558**		**2,065**		**13,623**		**14,137**	
72	Contractor		14,073		13,998		2,872		16,870		18,546
73	Labor		1,865		254		137		391		1,008
74	Materials		2,449		-		20		20		(5,628)
75	Business Expenses		48		(2,836)		(970)		(3,806)		176
76	Contingency				113		-		113		-
77	Other (Loadings, Chargebacks)		(6,677)		28		6		34		35
78	**Admin and Other**	**8,443**		**1,243**		**9**		**1,252**		**979**	
79	Contractor		2,345		740		-		740		645
80	Labor		599				-		-		-
81	Materials		953				-		-		-
82	Business Expenses		126		75		-		75		-
83	Contingency						-		-		-
84	Other (Loadings, Chargebacks)		4,420		428		9		437		334
85	**Air Quality**	**1,695**		**-**		**-**		**-**		**-**	
86	Contractor		315				-		-		-
87	Labor		129				-		-		-
88	Materials		867				-		-		-
89	Business Expenses		0				-		-		-
90	Contingency						-		-		-
91	Other (Loadings, Chargebacks)		383				-		-		-
92	**RCRA**	**2,878**		**-**		**-**		**-**		**-**	
93	Contractor		1,595				-		-		-
94	Labor		362				-		-		-
95	Materials		10				-		-		-
96	Business Expenses		5				-		-		-
97	Contingency						-		-		-
98	Other (Loadings, Chargebacks)		907				-		-		-
99	**316b**	**(1,348)**		**-**		**-**		**-**		**-**	
100	Contractor		(730)				-				
101	Labor		(202)				-				
102	Materials		(2)				-				
103	Business Expenses		(9)				-				
104	Contingency						-				
105	Other (Loadings, Chargebacks)		(405)				-				
106	**SEEG**	**(2,865)**		**-**		**-**		**-**		**-**	
107	Contractor		(1,595)				-				
108	Labor		(352)				-				
109	Materials		(10)				-				
110	Business Expenses		(5)				-				
111	Contingency						-				
112	Other (Loadings, Chargebacks)		(903)				-				
113	**All Other Environmental**	**747**		**3,024**		**6**		**3,031**		**48**	
114	Contractor		316		2,487		5		2,492		42
115	Labor		232		192		-		192		-
116	Materials		9		192		-		192		-
117	Business Expenses		2		155		1		156		6
118	Contingency		-				-				
119	Other (Loadings, Chargebacks)		189				-				
120	**Total Capital**	141,372	141,372	1,289,962	1,289,962	81,012	81,012	1,370,974	1,370,974	388,972	388,972

Schedule: B-5.1

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	2 Mos Ending 2/28/2023	12 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	26 Mos Ending 2/28/2025
1	**JHCampbell 1&2**	**$ 356**	**$ 1,037**	**$ 272**	**$ 1,665**
2	Contractor	$ 516	$ 397	$ 211	$ 1,124
3	Labor	$ 3	$ (3)	$ -	$ -
4	Materials	$ (4)	$ 315	$ -	$ 311
5	Business Expenses	$ (160)	$ 328	$ 61	$ 229
6	Contingency	$ -	$ -	$ -	$ -
7	Other (Loadings, Chargebacks)	$ 1	$ (1)	$ -	$ -
8	**JHCampbell 3**	**$ 1,169**	**$ 1,268**	**$ 360**	**$ 2,797**
9	Contractor	$ 1,694	$ (23)	$ 279	$ 1,950
10	Labor	$ 8	$ 52	$ -	$ 60
11	Materials	$ (12)	$ 535	$ -	$ 523
12	Business Expenses	$ (523)	$ 707	$ 81	$ 264
13	Contingency	$ -	$ -	$ -	$ -
14	Other (Loadings, Chargebacks)	$ 2	$ (2)	$ -	$ -
15	**DEKarn 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
16	Contractor	$ -	$ -	$ -	$ -
17	Labor	$ -	$ -	$ -	$ -
18	Materials	$ -	$ -	$ -	$ -
19	Business Expenses	$ -	$ -	$ -	$ -
20	Contingency	$ -	$ -	$ -	$ -
21	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
22	**DEKarn 3&4**	**$ 1,420**	**$ 11,027**	**$ 6,542**	**$ 18,988**
23	Contractor	$ 1,131	$ 8,219	$ 5,882	$ 15,232
24	Labor	$ 23	$ 142	$ 41	$ 206
25	Materials	$ -	$ 826	$ -	$ 826
26	Business Expenses	$ -	$ 2,080	$ 494	$ 2,574
27	Contingency	$ 3	$ 22	$ 125	$ 150
28	Other (Loadings, Chargebacks)	$ 262	$ (262)	$ -	$ -
29	**Zeeland**	**$ 4,986**	**$ 32,892**	**$ 15,286**	**$ 53,164**
30	Contractor	$ 4,320	$ 29,528	$ 13,561	$ 47,409
31	Labor	$ 47	$ 307	$ 48	$ 401
32	Materials	$ 32	$ 195	$ 258	$ 485
33	Business Expenses	$ 577	$ 2,789	$ 1,169	$ 4,535
34	Contingency	$ 11	$ 74	$ 250	$ 335
35	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
36	**Jackson Generating Station**	**$ 1,475**	**$ 14,502**	**$ 11,720**	**$ 27,697**
37	Contractor	$ 1,309	$ 12,918	$ 10,721	$ 24,948
38	Labor	$ 5	$ 46	$ 25	$ 76
39	Materials	$ 14	$ 111	$ 263	$ 388
40	Business Expenses	$ 142	$ 1,373	$ 711	$ 2,226
41	Contingency	$ 5	$ 55	$ -	$ 60
42	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
43	**Covert**	**$ -**	**$ 829,095**	**$ 20,274**	**$ 849,369**
44	Contractor	$ -	$ 13,146	$ 20,274	$ 33,420
45	Labor	$ -	$ -	$ -	$ -
46	Materials	$ -	$ -	$ -	$ -
47	Business Expenses	$ -	$ 815,949	$ -	$ 815,949
48	Contingency	$ -	$ -	$ -	$ -
49	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
50	**Solar**	**$ 1,732**	**$ 415,448**	**$ 269,457**	**$ 686,638**
51	Contractor	$ 281	$ 56,420	$ 75,238	$ 131,939
52	Labor	$ -	$ -	$ -	$ -
53	Materials	$ -	$ -	$ -	$ -
54	Business Expenses	$ 140	$ 49,232	$ 18,849	$ 68,221
55	Contingency	$ -	$ -	$ -	$ -
56	Other (Loadings, Chargebacks)	$ 1,312	$ 309,796	$ 175,371	$ 486,478

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	2 Mos Ending 2/28/2023	12 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	26 Mos Ending 2/28/2025
57	**Classic 7**	**$ -**	**$ -**	**$ -**	**$ -**
58	Contractor	$ -	$ -	$ -	$ -
59	Labor	$ -	$ -	$ -	$ -
60	Materials	$ -	$ -	$ -	$ -
61	Business Expenses	$ -	$ -	$ -	$ -
62	Contingency	$ -	$ -	$ -	$ -
63	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
64	**Hydros**	**$ 2,005**	**$ 34,657**	**$ 49,897**	**$ 86,558**
65	Contractor	$ 1,718	$ 27,445	$ 39,612	$ 68,776
66	Labor	$ 6	$ 46	$ 92	$ 144
67	Materials	$ -	$ -	$ -	$ -
68	Business Expenses	$ 224	$ 6,699	$ 9,484	$ 16,407
69	Contingency	$ 57	$ 466	$ 708	$ 1,232
70	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
71	**Ludington**	**$ 1,151**	**$ 12,472**	**$ 14,137**	**$ 27,759**
72	Contractor	$ 1,668	$ 15,202	$ 18,546	$ 35,416
73	Labor	$ 8	$ 383	$ 1,008	$ 1,399
74	Materials	$ (12)	$ 33	$ (5,628)	$ (5,608)
75	Business Expenses	$ (515)	$ (3,291)	$ 176	$ (3,630)
76	Contingency	$ -	$ 113	$ -	$ 113
77	Other (Loadings, Chargebacks)	$ 2	$ 32	$ 35	$ 69
78	**Admin and Other**	**$ 38**	**$ 1,214**	**$ 979**	**$ 2,231**
79	Contractor	$ 36	$ 704	$ 645	$ 1,385
80	Labor	$ -	$ -	$ -	$ -
81	Materials	$ -	$ -	$ -	$ -
82	Business Expenses	$ 2	$ 73	$ -	$ 75
83	Contingency	$ -	$ -	$ -	$ -
84	Other (Loadings, Chargebacks)	$ -	$ 437	$ 334	$ 771
85	**Air Quality**	**$ -**	**$ -**	**$ -**	**$ -**
86	Contractor	$ -	$ -	$ -	$ -
87	Labor	$ -	$ -	$ -	$ -
88	Materials	$ -	$ -	$ -	$ -
89	Business Expenses		$ -	$ -	$ -
90	Contingency		$ -	$ -	$ -
91	Other (Loadings, Chargebacks)		$ -	$ -	$ -
92	**RCRA**	**$ -**	**$ -**	**$ -**	**$ -**
93	Contractor		$ -	$ -	$ -
94	Labor		$ -	$ -	$ -
95	Materials		$ -	$ -	$ -
96	Business Expenses		$ -	$ -	$ -
97	Contingency		$ -	$ -	$ -
98	Other (Loadings, Chargebacks)		$ -	$ -	$ -
99	**316b**	**$ -**	**$ -**	**$ -**	**$ -**
100	Contractor		$ -	$ -	$ -
101	Labor		$ -	$ -	$ -
102	Materials		$ -	$ -	$ -
103	Business Expenses		$ -	$ -	$ -
104	Contingency		$ -	$ -	$ -
105	Other (Loadings, Chargebacks)		$ -	$ -	$ -
106	**SEEG**	**$ -**	**$ -**	**$ -**	**$ -**
107	Contractor		$ -	$ -	$ -
108	Labor		$ -	$ -	$ -
109	Materials		$ -	$ -	$ -
110	Business Expenses		$ -	$ -	$ -
111	Contingency		$ -	$ -	$ -
112	Other (Loadings, Chargebacks)		$ -	$ -	$ -
113	**All Other Environmental**	**$ -**	**$ 3,031**	**$ 48**	**$ 3,079**
114	Contractor		$ 2,492	$ 42	$ 2,534
115	Labor		$ 192	$ -	$ 192
116	Materials		$ 192	$ -	$ 192
117	Business Expenses		$ 156	$ 6	$ 162
118	Contingency		$ -	$ -	$ -
119	Other (Loadings, Chargebacks)		$ -	$ -	$ -
120	**SubTotal**	$ 14,332	$ 1,356,642	$ 388,972	$ 1,759,946
121	**Less Contingency**	$ 77	$ 730	$ 1,083	$ 1,890
122	**Grand Total**	$ 14,256	$ 1,355,912	$ 387,888	$ 1,758,056

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No.	Description	12 Months Ended 12/31/2022	12 Months Ending 12/31/2023	2 Months Ending 2/29/2024	14 Months Ending 2/29/2024	12 Months Ending 2/28/2025
1	Contractor	$ 99,467	$ 145,313	$ 33,808	$ 179,120	$ 185,012
2	Labor	$ 10,236	$ 1,090	$ 174	$ 1,264	$ 1,213
3	Materials	$ 14,311	$ 2,102	$ 121	$ 2,223	$ (5,107)
4	Business Expenses	$ 464	$ 866,998	$ 8,983	$ 875,981	$ 31,030
5	Contingency	$ -	$ 590	$ 217	$ 807	$ 1,083
6	Other (Loadings, Chargebacks)	$ 16,894	$ 273,869	$ 37,709	$ 311,579	$ 175,740
	Total	$ 141,372	$ 1,289,962	$ 81,012	$ 1,370,974	$ 388,972

	(a)	(b)	(c)	(d)	(e)	(f)
				Projected		
Line No.	Description	12 Months Ending 12/31/2023	2 Months Ending 2/29/2024	14 Months Ending 2/29/2024	12 Months Ending 2/28/2025	26 Months Ending 2/28/2005
1	Contractor	$ 145,313	$ 33,808	$ 179,120	$ 185,012	$ 364,133
2	Labor	$ 1,090	$ 174	$ 1,264	$ 1,213	$ 2,477
3	Materials	$ 2,102	$ 121	$ 2,223	$ (5,107)	$ (2,883)
4	Business Expenses	$ 866,998	$ 8,983	$ 875,981	$ 31,030	$ 907,011
5	Contingency	$ 590	$ 217	$ 807	$ 1,083	$ 1,890
6	Other (Loadings, Chargebacks)	$ 273,869	$ 37,709	$ 311,579	$ 175,740	$ 487,318
	Total	$ 1,289,962	$ 81,012	$ 1,370,974	$ 388,972	$ 1,759,946

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Consumers Energy Company
Summary of Projected Electric Capital Expenditures
For the projected test year ending February 28, 2025
($000's)

Generation Capital Expenditures

Line No.	(a) Description	(b) Projected Bridge Period 14 Months Ending 2/29/2024	(c)	(d) Projected Test Year 12 Months Ending 2/28/2025	(e)	(f) Reference
1	Campbell 1&2 Non-Environmental	$ 1,393		$ 272		A-12 (RTB-3) Page 2 line 1 Columns (d) and (f)
2	Campbell 1&2 "All Other Environmental"		$ 330		$ 14	
3	Campbell 3 Non-Environmental	$ 2,437		$ 360		A-12 (RTB-3) Page 2 line 8 Columns (d) and (f)
4	Campbell 3 "All Other Environmental"		$ 2,700		$ 18	
5	Karn 1&2 Non-Environmental	$ -		$ -		A-12 (RTB-3) Page 2 line 15 Columns (d) and (f)
6	Karn 1&2 "All Other Environmental"		$ -		$ -	
7	**Total Other Environmental**		$ 3,031		$ 31	

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
Generation Capital Projects greater than $1M
($000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected [1] Contingency	(h) Projected [1] Amount	(i) Actual Amount
1	2022	Coal Generation	Campbell 1	Non-Routine	Environmental	Air Preheater Baskets and Seals	$ -	$ 1,470	$ 1,819
2	2022	Coal Generation	Campbell 1	Routine	Environmental	Pulse Jet Fabric Filter Bag	$ 200	$ 1,019	$ 1,040
3	2022	Coal Generation	Campbell 3	Non-Routine	Condition-based	House Service Air Compressor Replacement	$ 267	$ 1,053	$ 1,207
4	2022	Coal Generation	Campbell 3	Routine	Environmental	Selective Catalytic Reduction Catalyst Management	$ 500	$ 1,960	$ 1,196
5	2022	Coal Generation	Campbell 3	Non-Routine	Condition-based	Campbell Unit 3 Diesel Generatior Controls	$ 19	$ 187	$ 1,172
6	2023	Coal Generation	Campbell Site Commons	Non-Routine	Condition-based	North and South Piegon Lake Jetties	$ -	$ 740	$ 1,003
7	2022	Gas/Oil Generation	Karn 3&4 Commons	Non-Routine	Asset Separation	Unit Separation	$ 500	$ 7,207	$ 1,605
8	2022	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement FFH	$ -	$ 8,200	$ 7,734
9	2022	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Reverse Osmosis Pretreatment System	$ 100	$ 8,700	$ 16,237
10	2022	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement Historical Extra Work	$ -	$ 950	$ 3,920
11	2022	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Long Term Service Agreement - Running Capital Contract	$ -	$ 8,160	$ 7,599
12	2022	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Zeeland Unit 1A Generator Step Up Transformer Rewind	$ -	$ 5,500	$ 8,878
13	2022	Hydro Generation	Croton	Routine	Condition-based	Croton 1 Wicket Gate	$ 100	$ 2,150	$ 4,072
14	2022	Hydro Generation	Croton	Routine	Condition-based	Croton 2 Wicket Gate	$ 100	$ 2,150	
15	2022	Hydro Generation	Hardy	Routine	Safety	Replace powerhouse roof	$ 100	$ 1,575	$ 1,711
16	2022	Hydro Generation	Hardy	Routine	Infrastructure	New Headquarters Building (previously was Croton HQ)	$ 300	$ 1,985	$ 2,740
17	2022	Hydro Generation	Hardy	Non-Routine	Regulatory	Auxiliary Spillway Remediation	$ 192	$ 4,700	$ 3,096
18	2022	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Spillway Hoist Replacement	$ 100	$ 1,900	$ 1,712
19	2022	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Transformer Foundation	$ 250	$ 2,487	$ 1,746
20	2022	Hydro Generation	Hodenpyl	Non-Routine	Safety	Electrical Safety Project	$ -	$ 2,220	$ 3,170
21	2022	Hydro Generation	Mio	Non-Routine	Regulatory	Left Retaining Wall Replacement	$ -	$ 3,650	$ 4,300
22	2022	Hydro Generation	Mio	Non-Routine	Safety	Electrical Safety Project	$ 190	$ 2,450	$ 1,677
23	2022	Hydro Generation	Mio	Non-Routine	Regulatory	Mio Downstream reverse filter	$ -	$ 570	$ 1,058
24	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	$ 220	$ 3,090	$ 2,325
25	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Replace Lower Penstock Expansion Joint Chamber Waterstop	$ 200	$ 3,878	$ 4,223
26	2022	Hydro Generation	Ludington Site Commons	Non-routine	Economic	Upgrade and Overhaul	$ -	$ 5,370	$ 8,796
27	2022	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	480V Motor Control Center for DLC	$ -	$ 845	$ 1,538
28	2022	Renewables	Solar Commons	Non-Routine	New Generation	Solar - 2021 Bid Event (250 MW)	$ -	$ 20,333	$ 22,789
29	**Total 2022 Projects**						**$ 3,337**	**$ 104,498**	**$ 118,365**

Note:
(1) Projected amounts were taken from Case No. U-21224

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
Generation Capital Projects greater than $1M
($000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Engineering Internal or External	(h) Project Bid Issued	(i) Full Internal Budget Approval	(j) Work Item Description	(k) Planned Amount	(l) Project Reduction	(m) Contingency Amount	(n) Projected Amount
1	Bridge Period	Coal Generation	Campbell 3	Routine	Environmental	Class 3	Internal	In Progress	Approved	SCR Catalyst Management	$ 2,403	$ 100	$ -	$ 2,303
2	Bridge Period	Gas Generation	Covert Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running capital contract	$ 9,761		$ -	$ 9,761
3	Bridge Period	Gas Generation	Covert Commons	Routine	Condition-based	Class 3	NA	No	Approved	Non LTSA Capital - Extras not included in contract	$ 3,943		$ -	$ 3,943
4	Bridge Period	Gas Generation	Covert Commons	Non-Routine	Acquisition	Class 1	NA	Yes	Approved	Covert Generating Facility Acquisition	$ 815,000		$ -	$ 815,000
5	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Cooling Tower Rebuild	$ 4,250	$ 279	$ -	$ 3,971
6	Bridge Period	Gas/Oil Generation	Karn 3&4	Non-Routine	Condition-based	Class 3	External	No	Approved	Tank Farm Storage Tank Heating Line Replacement	$ 1,350	$ 96		$ 1,254
7	Bridge Period	Gas/Oil Generation	Karn 3&4	Non-Routine	Condition-based	Class 3	External	No	Approved	Sync Wire Replacement	$ 1,450			$ 1,450
8	Bridge Period	Gas/Oil Generation	Karn 3&4 Commons	Non-Routine	Asset Separation	Class 3	External	No	Approved	Unit Separation	$ 1,790		$ -	$ 1,790
9	Bridge Period	Gas Generation	Jackson Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	GE Long Term Service Agreement FFH	$ 9,571		$ -	$ 9,571
10	Bridge Period	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 3	Internal	No	Approved	7EA Casing replacement & Hot section overhaul	$ 2,288	$ 200	$ -	$ 2,088
11	Bridge Period	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	HRSG Burner Element Isolation Valves Addition	$ 2,021		$ -	$ 2,021
12	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running Capital Contract	$ 9,520		$ -	$ 9,520
13	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Milestone Outage Capital to GE - Part of LTSA Contract	$ 7,870		$ -	$ 7,870
14	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 1	Internal	Yes	Approved	Phase 2 599 699 345kV Breaker Replacement	$ 1,302	$ 79	$ -	$ 1,223
15	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	HRSG Casing Replacement	$ 2,900	$ 97	$ -	$ 2,803
16	Bridge Period	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 2	Internal	No	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	$ 3,200	$ 300	$ -	$ 2,900
17	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	External	Yes	Approved	Zeeland Unit 4 Field Rewind of Generator Rotor	$ 1,250	$ 45		$ 1,205
18	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	External	Yes	Approved	Zeeland Unit 3 Field Rewind	$ 1,250	$ 45		$ 1,205
19	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 3	Internal	Yes	Approved	Generator Step Up Transformer Replacement (Spare	$ 2,883		$ -	$ 2,883
20	Bridge Period	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 1	Internal	Yes	Approved	Zeeland Unit 1 Generator Step Up Transformer Rewin	$ 4,700	$ 96	$ -	$ 4,604
21	Bridge Period	Hydro Generation	Alcona	Non-Routine	Infrastructure	Class 3	External	No	Approved	Core Wall Remediation Project	$ 3,600	$ 1,790	$ -	$ 1,810
22	Bridge Period	Hydro Generation	Cooke	Non-Routine	Safety	Class 3	Internal	No	Approved	Spillway Hoist Replacement	$ 2,100		$ -	$ 2,100
23	Bridge Period	Hydro Generation	Five Channels	Non-Routine	Regulatory	Class 3	External	No	Approved	Dead Bay and Log Chute Remediation	$ 2,972	$ 990	$ -	$ 1,982
24	Bridge Period	Hydro Generation	Five Channels	Non-Routine	Regulatory	Class 3	External	No	Approved	Headgate Project	$ 3,062	$ 1,080	$ -	$ 1,982
25	Bridge Period	Hydro Generation	Hardy	Non-Routine	Regulatory	Class 3	External	No	Approved	Auxiliary Spillway Remediation	$ 3,459	$ -	$ -	$ 3,459
26	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Hodenpyl 1 Generator Rewind	$ 3,310	$ 210	$ -	$ 3,101
27	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Class 3	External	No	Approved	Spillway Hoist Replacement	$ 2,958	$ 94	$ -	$ 2,864
28	Bridge Period	Hydro Generation	Webber	Non-Routine	Condition-based	Class 1	External	Yes	Approved	Unit 1 Generator Rewind	$ 1,020		$ -	$ 1,020
29	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Probable Maximum Flood Project	$ 2,386	$ 487		$ 1,899
30	Bridge Period	Hydro Generation	Rogers	Non-Routine	Condition-based	Class 3	Internal	Yes	Approved	Unit 4 Generator Rewind	$ 2,600			$ 2,600
31	Bridge Period	Hydro Generation	Mio	Non-Routine	Safety	Class 2	External	Yes	Approved	Electrical Safety Project	$ 1,225	$ 138		$ 1,086
32	Bridge Period	Hydro Generation	Webber	Non-Routine	Infrastructure	Class 2	External	Yes	Approved	Webber Left Downstream Spillway Abutment Wall	$ 3,200	$ 225		$ 2,975
33	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	Class 4	External	No	Approved	Oil Water Separator Replacement	$ 1,263	$ 100		$ 1,163
34	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 1-6 DCS Control Relay Replacement	$ 1,348			$ 1,348
35	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Class 3	External	No	Approved	Replace Lower Penstock Expansion Joint Chamber Waterstop	$ 2,433	$ 7	$ -	$ 2,425
36	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Class 1	External	Yes	Approved	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	$ 2,864	$ 140	$ -	$ 2,724
37	Bridge Period	Hydro Generation	Ludington Site Commons	Non-Routine	Regulatory	Class 1	Internal	Yes	Approved	Replace Barrier Net Panels	$ 1,089	-	$ -	$ 1,089
38	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2019 Bid Event (150 MW)	$ 233,064		$ -	$ 233,064
39	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2020 Bid Event (150 MW)	$ 122,186		$ -	$ 122,186
40	Bridge Period	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/Awarded Self-Build 2022	CE Tech Specs/External Design	Yes	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	$ 61,930			$ 61,930
41	**Total Bridge Period Projects**										**$ 1,346,768**	**$ 6,597**	**$ -**	**$ 1,340,171**

Note:
(1) Planned amounts were reduced by project reductions and contingency to arrive at the projected amounts

MICHIGAN PUBLIC SERVICE COMMISSION **Schedule: B-5.1**

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2022 through 2025
Generation Capital Projects greater than $1M
($000's)

Case No.: U-21389
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.1
Page: 10 of 10
Witness: RTBlumenstock
Date: May 2023

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Engineering Internal or External	(h) Project Bid Issued	(i) Full Internal Budget Approval	(j) Work Item Description	(k) Planned Amount	(l) Project Reduction	(m) Contingency Amount	(n) Projected Amount
1	Test Year	Gas Generation	Covert Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running capital contra	$ 13,848	-	$ -	$ 13,848
2	Test Year	Gas Generation	Covert Commons	Routine	Condition-based	Class 3	NA	No	Approved	Non Long Term Service Agreemen Capital - Extras not included in contra	$ 5,510	-	$ -	$ 5,510
3	Test Year	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	Class 2	External	No	Approved	LM 1 - 6 SAC Extended Life Combusto	$ 1,338	-	$ -	$ 1,338
4	Test Year	Gas Generation	Jackson Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	GE Long Term Service Agreement FFI	$ 8,245	-	$ -	$ 8,245
5	Test Year	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Class 2	Internal	Yes	Approved	Purchase of Site Spare GSU	$ 3,917	-	$ -	$ 3,917
6	Test Year	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Class 1	NA	Yes	Approved	Long Term Service Agreement - Running Capital Contra	$ 8,160	-	$ -	$ 8,160
7	Test Year	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Internal	No	Approved	Karn 3 Cooling Tower Internal Structure Replaceme	$ 5,000	-	$ -	$ 5,000
8	Test Year	Hydro Generation	Alcona	Non-Routine	Regulatory	Class 4	Internal	No	Approved	Risk Informed Decision Making Resolutio	$ 2,500	-	$ -	$ 2,500
9	Test Year	Hydro Generation	Alcona	Non-Routine	Infrastructure	Class 3	External	No	Approved	Core Wall Remediation Projec	$ 9,057	$ -	$ -	$ 9,057
10	Test Year	Hydro Generation	Foote	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 2 Wicket Gates Replacement Projec	$ 1,253	-	$ -	$ 1,253
11	Test Year	Hydro Generation	Hardy	Routine	Safety	Class 3	External	No	Approved	Electrical Safety Projec	$ 1,500	-	$ -	$ 1,500
12	Test Year	Hydro Generation	Allegan	Non-Routine	Condition-based	Class 3	External	No	Approved	Unit 1 Wicket Gate Replacemen	$ 1,333	-	$ -	$ 1,333
13	Test Year	Hydro Generation	Five Channels	Non-Routine	Safety	Class 2	External	Yes	Approved	Trash Rack Ergonomics Projec	$ 1,728	-	$ -	$ 1,728
14	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Class 2	External	Yes	Approved	Hardy Splash Wall Replacemen	$ 3,134	-	$ -	$ 3,134
15	Test Year	Hydro Generation	Webber	Non-Routine	Condition-based	Class 1	External	Yes	Approved	Unit 1 Generator Rewinc	$ 4,750	-	$ -	$ 4,750
16	Test Year	Hydro Generation	Foote	Non-Routine	Safety	Class 3	External	No	Approved	ADA Ramp Investigation and replacemer	$ 1,463	-	$ -	$ 1,463
17	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Class 3	External	No	Approved	Downstream Wall	$ 3,450	-	$ -	$ 3,450
18	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Powerhouse Left Embankment Retaining Wa	$ 1,083	-	$ -	$ 1,083
19	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Class 4	External	No	Approved	Probable Maximum Flood Projec	$ 3,272	-	$ -	$ 3,272
20	Test Year	Hydro Generation	Cooke	Non-Routine	Condition-based	Class 3	External	No	Approved	Head Gate Replacement Projec	$ 2,080	-	$ -	$ 2,080
21	Test Year	Hydro Generation	Ludington Site Commons	Non-routine	Condition-based	Class 3	External	No	Approved	Unit 1-6 DCS Control Relay Replacemer	$ 2,501	-	$ -	$ 2,501
22	Test Year	Hydro Generation	Ludington Site Commons	Routine	Infrastructure	Class 3	External	No	Approved	Administrative Building Additior	$ 2,714	-	$ -	$ 2,714
23	Test Year	Hydro Generation	Ludington Site Commons	Non-Routine	Regulatory	Class 1	Internal	Yes	Approved	Replace Barrier Net Panels	$ 1,753	-	$ -	$ 1,753
24	Test Year	Hydro Generation	Ludington Site Commons	Non-Routine	Infrastructure	Class 4	External	No	Approved	Intake Gate and Gate House Mechanical Replaceme	$ 1,118	-	$ -	$ 1,118
25	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2019 Bid Event (Mustang Mile 150 MW	$ 49,337	-	$ -	$ 49,337
26	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/BTA Executed 2021	CE Tech Specs/External Design	Yes	Approved	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW	$ 104,980	-	$ -	$ 104,980
27	Test Year	Renewables	Solar Commons	Non-Routine	New Generation	Class 1/Awarded Self-Build 2022	CE Tech Specs/External Design	Yes	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW	$ 115,140	-	$ -	$ 115,140
28	**Total Test Year Projects**										**$ 360,164**	**$ -**	**$ -**	**$ 360,164**

Note:
(1) Planned amounts were reduced by project reductions and contingency to arrive at the projected amounts

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2022 through 2025
($000's)

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)

Witness: RTBlumenstock
Date: May 2023

GENERATION OPERATION AND MAINTENANCE EXPENSES

	(a)	(b)		(c)		(d)	
Line No.	Description	Historical 12 Months Ended 12/31/2022		Projected Bridge Period 14 Months Ending 02/29/2024		Projected Test Year 12 Months Ending 02/28/2025	
1	**BASE O&M**	$	106,819	$	136,474	$	126,416
2	**ADJUSTED O&M**						
3	Environmental Operations	$	10,802	$	8,714	$	5,860
4	Major Maintenance	$	32,411	$	27,278	$	31,976
5	Retention & Separation	$	2,339	$	14,917	$	18,220
6	**TOTAL O&M**	**$**	**150,030.653**	**$**	**172,465.3**	**$**	**164,251.9**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Years 2022 through 2025
($000's)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	2022 Actual	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2022	Merit & Inflation 12 Mos Ending Dec 31, 2023	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2023	Merit & Inflation 12 Mos Ending Dec 31, 2024	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 2 Mos Ending 2/28/2025	Other Adjustments	Projected O&M 12 Mos Ending 2/28/2025
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	**Line Item 1**	**150,031**	**150,031**	**5,851**	**155,882**	**3,429**	**159,311**	**558**	**4,383**	**164,252**
	Labor	91,790	91,790	3,580	95,370	2,098	97,468	341	2,699	100,509
	Material	6,931	6,931	270	7,201	158	7,359	26	188	7,573
	Contractor	16,999	16,999	663	17,662	389	18,051	63	474	18,588
	Non-Labor Overheads		0	0	0	0	0	0	0	0
	Non-Labor Other	34,311	34,311	1,338	35,649	784	36,433	128	1,022	37,582

Notes

		2023	2024	2025
4	Annual merit increase			
	Annual merit increase	3.9%	2.2%	2.1%
	Number of months in the period	12	12	2
	Pro-rated merit increase	3.9%	2.2%	0.4%
	Annual inflation rates per WP-JCA-xx			
	Annual inflation rates	3.9%	2.2%	2.1%
	Number of months in the period	12	12	2
	Pro-rated inflation rate	3.9%	2.2%	0.4%

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21389
Exhibit No.: A-41 (RTB-4)

Witness: RTBlumenstock
Date: May 2023

Consumers Energy Company
Summary of the Generation Major Maintenance O&M Expense
For the Years 2022 through 2025
($000's)

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2022	(c) Projected Bridge Period 14 Months Ending 02/29/2024	(d) Projected Test Year 12 Months Ending 02/28/2025
1	**Major Maintenance**			
2	Campbell 1&2	$ 3,307	$ 1,875	$ 1,782
3	Campbell 3	$ 3,196	$ 2,623	$ 2,229
4	Karn 1&2	$ 6,291	$ 528	$ 223
5	Karn 3&4	$ 607	$ 1,579	$ 2,017
6	Classic 7	$ (636)	$ 326	$ 334
7	Zeeland Generating Station	$ 2,761	$ 5,171	$ 4,658
8	Jackson Generating Station	$ 7,546	$ 3,237	$ 3,061
9	Covert Generating Stations	$ -	$ 3,925	$ 6,025
10	Ludington	$ 4,921	$ 3,571	$ 4,422
11	Hydros	$ 4,418	$ 4,174	$ 6,298
12	Solar	$ -	$ 144	$ 778
13	Admin & Other	$ -	$ 125	$ 150
14	**TOTAL Major Maintenance**	**$ 32,411**	**$ 27,278**	**$ 31,976**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 11

Blumenstock 2024 Direct Testimony

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.
_____________________________________/

Case No. U-21585

Volume 5

PUBLIC

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Monday, November 4, 2024, at 9:03 AM Eastern.

APPEARANCES:

GARY A. GENSCH, JR., ESQ.
ANNE M. UITVLUGT, ESQ.
EVAN B. KEIMACH, ESQ.
SPENCER A. SATTLER, ESQ.
BRET A. TOTORAITIS, ESQ.
MARK R. RUSZKIEWICZ, ESQ.
Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Appearances continued)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-21585

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

May 2024

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan, 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Supply Engineering. I began employment at the Company in May 1994 in the electric transmission planning area where I performed planning studies on the Company's distribution and transmission systems. In April 2002, I was assigned to the electric operations area where I oversaw engineering operations for the distribution and transmission systems. In August 2009, I was assigned to the fuel supply area where I oversaw the Company's purchasing and transport functions for fuel for electric generation. In June 2011, I assumed additional responsibilities including oversight of the Company's interaction in the Midcontinent Independent System Operator, Inc. ("MISO") markets; wholesale settlements and transactions functions; Power Supply Cost Recovery ("PSCR") activities; and planning for electric supply necessary to satisfy customers' energy and capacity needs. In September 2019, I assumed the role of Executive Director of Electric Planning, overseeing the company-wide efforts for all electric planning. In September 2022, I assumed my current position as Executive Director of Electric Supply Engineering.

Q. What are your responsibilities as Executive Director of Electric Supply Engineering?

A. My responsibilities as Executive Director of Electric Supply Engineering include oversight of all activities associated with planning and design for the Company's electric generation portfolio.

Q. What is your formal educational experience?

A. I received a Bachelor of Science degree in 1992 and a Master of Science degree in 1994, both in Electrical Engineering from Michigan Technological University.

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

A. Yes, I provided testimony in the following MPSC cases:

- Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;

- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;

- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan ("IRP") pursuant to MCL 460.6t and for other relief;

- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;

- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and

- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department ("Generation") requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy's coal-, oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;

- Support the Company's generation asset strategy to: (1) focus continued investment in those generating units (Zeeland Generating Station ("Zeeland Plant", "ZGS" or "Zeeland"), New Covert Generating Facility ("Covert Plant" or "Covert"), and Jackson Generating Station ("Jackson Plant", "JGS" or "Jackson")) which provide the most long-term economic benefit for customers; and (2) sustain safe and environmentally compliant operations for its coal generating units (J.H. Campbell ("Campbell") Units 1, 2, and 3 through their retirement dates;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate ("ROR") projections for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation, for the projected test year ending February 28, 2026;

- Support the reasonableness and prudence of the capital expenditures for coal generation, oil- and gas-fired peaking generation, and certain hydroelectric power generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;

- Support the reasonableness and prudence of the projected investment for Company-owned Solar Generation for the historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") and fuel handling expenses for coal generation, oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2023, the 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026;

- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn ("Karn") Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2023;

- Support the reasonableness and prudence of the O&M expenses for the Campbell Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2023, 14-month bridge period beginning January 1, 2024 and ending February 28, 2025, and the projected test year ending February 28, 2026; and

- Describe the environmental regulations with which the Company's electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz's testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness

Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the IRP competitive solicitation process and timeline associated with the IRP solar initiative investment, including the build transfer agreements ("BTAs") and their associated projected capital expenditures. In addition, Mr. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Adam J. Monroe supports capital investments in River Hydro facilities, including the Hardy Dam.

Company witness Josnelly C. Aponte supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at both the Karn and Campbell sites in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)		Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)		Generating Unit Availability Projections;
Exhibit A-12 (RTB-3)	Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2023 through February 2026;
Exhibit A-43 (RTB-4)		Summary of the Generation O&M Expense for the Years 2023 through February 2026;
Exhibit A-44 (RTB-5)		Muskegon River Economic Impact Studies;
Exhibit A-45 (RTB-6)		Karn Unit 3 Cooling Tower Internal Structure Replacement Concept Approval; and

Exhibit A-46 (RTB-7)	Zeeland Phase I Gas Turbine Upgrade Concept Approval.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and its generating asset projected performance metrics. Included in this section is a discussion of the Company's River Hydro strategy, its compliance with the Settlement Agreement in Case No. U-21224 and the March 1, 2024 Order in Case No. U-21389, the Request for Proposals ("RFP") for the divestiture of the River Hydro facilities, the Company's community outreach activities, and the Company's pursuit of external funding. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives and also the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of January 2, 2024, the Company's total projected owned generation assets for the 2023/2024 Planning Year had a Generator Verification Test Capacity ("GVTC") of 5,612 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
COAL FIRED				
JH Campbell 1	West Olive, MI	1962	2025	261
JH Campbell 2	West Olive, MI	1967	2025	356
JH Campbell 3*	West Olive, MI	1980	2025	784 (owned share)
OIL OR GAS FIRED				
Covert	Covert, MI	2004	2040	1089
DE Karn 3	Essexville, MI	1975	2031	594
DE Karn 4	Essexville, MI	1977	2031	606
Zeeland CC	Zeeland, MI	2002	2041	532
Zeeland 1A	Zeeland, MI	2002	2041	159
Zeeland 1B	Zeeland, MI	2002	2041	159
Jackson	Jackson, MI	2002	2041	538
HYDROELECTRIC				
Alcona	Alcona County, MI	1924	n/a	3
Allegan	Allegan County, MI	1936	n/a	1
Cooke	Iosco County, MI	1911	n/a	7
Croton	Newaygo County, MI	1907	n/a	2
Five Channels	Iosco County, MI	1912	n/a	6
Foote	Iosco County, MI	1918	n/a	3
Hardy	Newaygo County, MI	1931	n/a	32
Hodenpyl	Wexford County, MI	1925	n/a	5
Loud	Iosco County, MI	1913	n/a	5
Mio	Oscoda County, MI	1916	n/a	2
Rogers	Mecosta County, MI	1906	n/a	2
Tippy	Manistee County, MI	1918	n/a	6
Webber	Ionia County, MI	1907	n/a	1
RENEWABLES				
Lake Winds	Mason County, MI	2012	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	2048	
Crescent Wind	Jonesville, MI	2021	2051	150
Gratiot Farms Wind	Alma, MI	2021	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	2054	201
Solar Gardens- GVSU	Grand Rapids, MI	2016	2046	1.6
Solar Gardens- WMU	Kalamazoo, MI	2016	2046	0.6
Cadillac Solar Garden	Cadillac, MI	2021	2051	0.2
Circuit West	Grand Rapids, MI	2019	2049	0.3
ENERGY STORAGE				
Ludington Units 1-6**	Ludington, MI	1973	2069	1169 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("LPS" or "Ludington") Units 1 through 6?

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 1,169 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous electric rate case, Case No. U-21389?

A. No. There have been no changes to the retirement dates for the Company's owned generation units. The only change to the Company's owned generation units was the addition of Heartland Wind Park which began commercial operation on December 29, 2023.

Q. How will the Company continue to meet its load requirements with the retirement of the Campbell units in 2025?

A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn

Units 3 and 4, and the addition of Zonal Resource Credits ("ZRCs") by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

The IRP one-time solicitation resulted in the Company's January 12, 2024, filing of the Tibbits Energy Storage, LLC Power Purchase Agreement ("PPA"), a 100-MW battery storage project which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years, with deliveries expected to commence by May 31, 2025 with an expected PPA termination date of May 31, 2045. The IRP one-time solicitation also resulted in the Company's May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery storage energy project. The Century Oaks Energy Storage LLC PPA also has a term of 20 years and, with deliveries expected to commence by May 31, 2026, with an expected PPA termination date of May 31, 2046.

<u>GENERATION ASSET STRATEGY</u>

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on providing safe, reliable, regulatory compliant, and economic energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs, as approved by the MPSC.

Q. How does the Company's generation asset strategy apply to the Company's various generating units?

A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations. A detailed discussion of River Hydro compliance is discussed in the direct testimony of Company witness Monroe.

Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP, the Company will concentrate investment in new renewable energy resources, and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit. The coal-fired Campbell units will have less investment as they approach retirement in 2025. During 2023, the Company's Zeeland and Jackson Plants produced over 41% of the energy value and approximately 25% of the capacity value realized by the Company's electric generating fleet (excluding renewables). The addition of the Covert Plant on June 1, 2023 significantly increased the energy and capacity value for the Company's gas-fired generation. During its seven months of operation during 2023, the Covert Plant contributed almost 28% of the total energy value of the Company's electric generating fleet (excluding renewables) and represents over 18% of the generation fleet's capacity value. As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2023 net energy and capacity value by asset type:

FIGURE 1

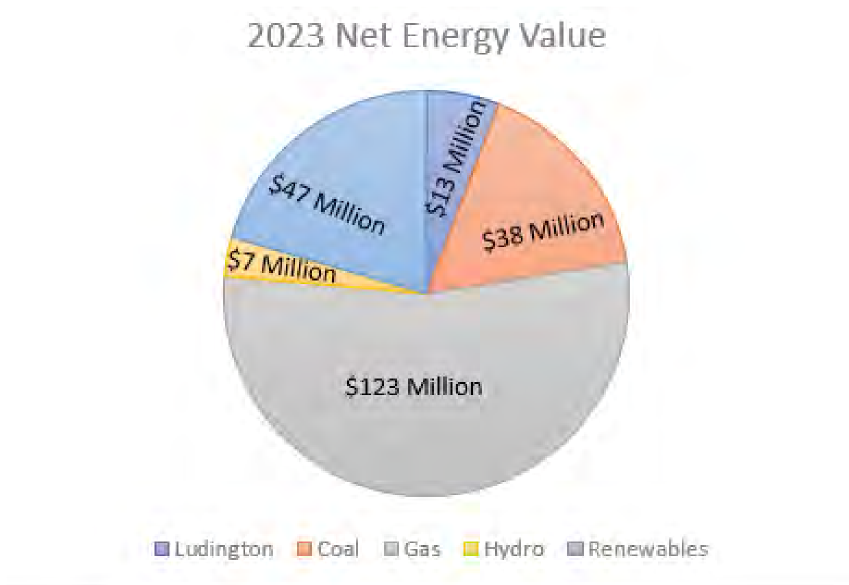
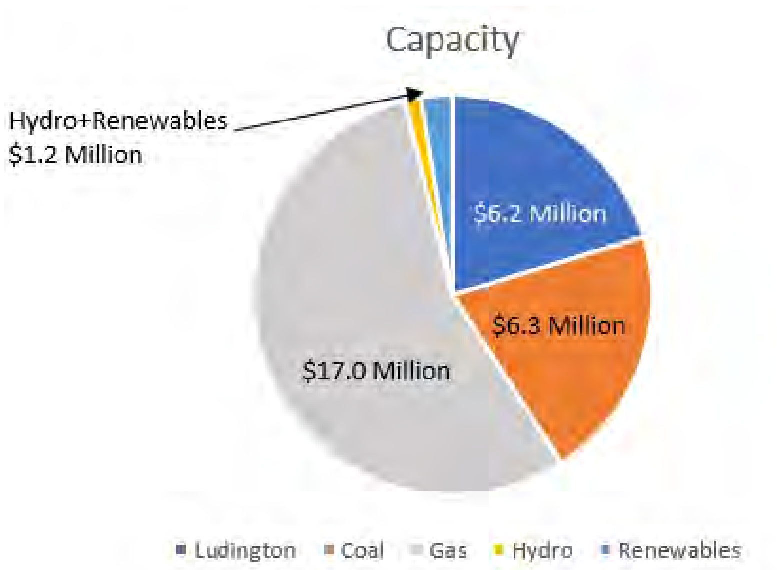


FIGURE 2



Q. How does the Company's generation asset strategy apply to the balance of the Company's generating units?

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value, and consistency with the Company's currently approved IRP expected retirement dates. The Company will continue to maintain its generating units, including the River Hydro facilities, to ensure safe and environmentally compliant operations. With the exception of the River Hydro facilities, I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony describing projected generating unit availability. Company witness Monroe will provide additional detail regarding the Company's generation asset strategy for the River Hydro facilities.

Q. Has the Company's existing generation asset strategy changed as a result of the 2023 Michigan energy legislation?

A. No. While Public Act ("PA") 235 of 2023 requires the Company to achieve a 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed to an aggressive change in its generation asset portfolio mix through its 2018 and 2021 IRPs. Pursuant to PA 235 of 2023, the Company will be filing a renewable energy plan amendment no later than November 15, 2024, which will reflect its plans to comply with the new renewable energy laws.

<u>PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS, AND NET ENERGY VALUE</u>

Q. Please describe Exhibit A-41 (RTB-1).

A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending February 28, 2026, for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's coal generation, peaking generation, and hydraulic power generation for the projected test year beginning March 1, 2025 and ending February 28, 2026. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

Q. What factors cause an increase or decrease in ROR?

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates decreases ROR. Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

Q. How are ROR projections for the Generating units developed?

A. The ROR projections for the projected test year ending February 28, 2026 were developed from the five-year (2019-2022) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2), column (b).

Q. Please define PF.

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the combustion of a coal blend with a lower heat content than is required to achieve the net demonstrated capability of the unit.

Q. What strategy does the Company employ to minimize the impact of planned outages on its customers?

A. Consistent with the Company's generation asset strategy, the Company endeavors to schedule planned generating unit outages during periods in which the margin between the generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater total NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand. However, with the introduction of seasonal capacity in the MISO market, the Company will also consider the impact of outage scheduling on capacity accreditation for the four capacity seasons. Company witness Metz describes seasonal capacity in more detail in her testimony.

Q. Please define Projected Availability.

A. Projected Availability is a measure of the percent of time that a generating unit or category of generating units is projected to be available to generate electricity.

Q. How is Projected Availability determined for each generating unit or category of generating units?

A. The Projected Availability for each generating unit or category of generating unit is calculated as (100% - PF) * (100% – ROR). Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

Q. How does the Company's generation asset strategy inform Projected Availability?

A. As I previously discussed, the Company's generation asset strategy and associated generation investment will focus on each unit's ability to provide economic value to customers through the unit's ability to produce energy and capacity value in the respective MISO markets. As such, those generating units or category of generating unit providing the greatest amount of economic value to customers will be targeted to achieve the highest projected availabilities.

Q. How can the Company impact Projected Availability for a generating unit?

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

Q. Does the Company attempt to maximize availability for all its generating units or category of generating units?

A. No. Consistent with the Company's generation asset strategy, the Company focuses on sustaining availability for those generating units which provide the greatest economic benefit to customers through the energy value provided. The Company's generating units get dispatched by MISO as part of the MISO energy market. Based upon the Company's projected dispatch likelihood for each unit, the Company will rank the generating units from highest economic value to least economic value, and manage the PF and the ROR, and therefore the unit's Availability, to allow for the highest customer value. Or, stated differently, the PF and ROR values may be allowed to be higher (lower unit Availability) for the lower economic value units, and will be managed to lower values (higher unit Availability) for higher economic value units.

Q. How does the Availability projection reflect the customer benefit?

A. An improvement in Availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis. Additionally, higher availability increases the ZRCs, increasing the capacity value of the unit.

Q. How does the Company measure the customer benefit resulting from increased generation?

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-42 (RTB-2), column (f), which identifies five-year (2019-2023) actual NEV amounts.

Q. What can the Company do to positively affect NEV?

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

Q. Does the cost of production vary for the Company's generating units?

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for its customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

Q. Why is the measurement of NEV important to the Company and its customers?

A. Positive NEV reflects a direct and immediate reduction to customer power supply costs and consideration of NEV provides a basis for making operational and financial decisions in order to maximize the customer value of the generating unit.

Q. What is another measure the Company uses to evaluate economic projects for its generating units?

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the capacity value of the Company's generating units in the 2023-2024 PRA for Zone 7. Company witness Metz discusses the capacity value of the Company's generating units in the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC[1] MW	MISO SUMMER SAC[2] MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[3]	CAPACITY VALUE ZONE 7 (75% CONE)[4]
COAL FIRED					
JH Campbell 1	West Olive, MI	261.3	239.5	$ 1,311,263	$ 19,023,796
JH Campbell 2	West Olive, MI	355.5	265.2	$ 1,451,970	$ 21,065,181
JH Campbell 3	West Olive, MI	784.3 (owned share)	647.8	$ 3,546,705	$ 51,455,596
OIL OR GAS FIRED					
Covert	Covert, MI	1088.6	1028.5	$ 5,631,038	$ 81,695,092
DE Karn 3	Essexville, MI	593.5	308.2	$ 1,687,395	$ 24,480,727
DE Karn 4	Essexville, MI	606.3	389.3	$ 2,131,418	$ 30,922,605
Zeeland CC	Zeeland, MI	532.1	525.3	$ 2,876,018	$ 41,725,262
Zeeland 1A	Zeeland, MI	159.4	164.1	$ 898,448	$ 13,034,676
Zeeland 1B	Zeeland, MI	158.8	163.5	$ 895,163	$ 12,987,018
Jackson	Jackson, MI	537.7	527	$ 2,885,325	$ 41,860,295
HYDROELECTRIC					
Alcona	Alcona County, MI	3	3	$ 16,425	$ 238,294
Allegan	Allegan County, MI	1.1	1.1	$ 6,023	$ 87,374
Cooke	Iosco County, MI	7.1	6.8	$ 37,230	$ 540,133
Croton	Newaygo County, MI	2.3	2.3	$ 12,593	$ 182,692
Five Channels	Iosco County, MI	6.3	6.1	$ 33,398	$ 484,531
Foote	Iosco County, MI	2.9	3	$ 16,425	$ 238,294
Hardy	Newaygo County, MI	32.4	31.1	$ 170,273	$ 2,470,313
Hodenpyl	Wexford County, MI	4.5	4.5	$ 24,638	$ 357,441
Loud	Iosco County, MI	4.9	4.7	$ 25,733	$ 373,327
Mio	Oscoda County, MI	1.5	1.6	$ 8,760	$ 127,090
Rogers	Mecosta County, MI	2.3	2.4	$ 13,140	$ 190,635
Tippy	Manistee County, MI	6.2	6.2	$ 33,945	$ 492,474
Webber	Ionia County, MI	1	1	$ 5,475	$ 79,431
RENEWABLES					
Lake Winds	Mason County, MI	100.8	14.7	$ 80,483	$ 1,167,640
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	38.1	$ 208,598	$ 3,026,333
Crescent Wind	Jonesville, MI	150	19.2	$ 105,120	$ 1,525,081
Gratiot Farms Wind	Alma, MI	150	29.9	$ 163,703	$ 2,374,996
Heartland Farms Wind Park	Ithaca, MI	201	36.4	$ 199,290	$ 2,891,299
Solar Gardens- GVSU	Grand Rapids, MI	1.6	1.7	$ 9,308	$ 135,033
Solar Gardens- WMU	Kalamazoo, MI	0.6	0.6	$ 3,285	$ 47,659
Cadillac Solar Garden	Cadillac, MI	0.2	0.2	$ 1,095	$ 15,886
Circuit West	Grand Rapids, MI	0.3	0.3	$ 1,643	$ 23,829
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1168.8 (owned share)	1138.6	$ 6,233,835	$ 90,440,478

1 ISAC = Intermediate seasonal accredited capacity
2 SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours
3 2023-2024 PRA Settlement price of $15/MW-day for Zone 7.
4 2023-2024 PRA 75% CONE price of $217.62/MW-day for Zone 7.

Q. Please provide an overview of the generation asset strategy for Campbell Units 1 and 2.

A. The strategic plan for Campbell Units 1 and 2 is predicated on their planned retirement on May 31, 2025, as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Units 1 and 2 is to maintain economic dispatch and capacity value from the customer's perspective. The major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Campbell Units 1 and 2 impact their projected performance?

A. It is anticipated that the unit performance will degrade from current performance for both Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units near retirement. Based upon the Campbell Units 1 and 2 major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 16.00% at Campbell Unit 1 and 15.00% at Campbell Unit 2 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c). During the five-year historical period from 2019 through 2023, Campbell Unit 1 had an ROR of 16.89% and Campbell Unit 2 had an ROR of 30.27% as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Units 1 and 2 in the test year?

A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 28.30% and 85.00%, respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF of 66.30%, as shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned Campbell Unit 1 outage for the test year is scheduled to begin on April 1, 2025 and last for 60 days, as reflected on Exhibit A-41 (RTB-1), line 5. Projected Availability for Campbell Unit 2 reflects a projected ROR of 15.00% and a PF of 0.00%, as shown on Exhibit A-42 (RTB-2), line 2, columns (c) and (d). No outages are planned at Campbell Unit 2 for the test year ending February 28, 2026.

Q. How does the availability for Campbell Units 1 and 2 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2019 through 2023, Campbell Unit 1 had an NEV of $94.3 million and Campbell Unit 2 had an NEV of $83.3 million. The 2023 NEV for each of these units was $6.0 million and $2.8 million for Campbell Units 1 and 2, respectively.

Q. Please quantify the capacity value for Campbell Units 1 and 2.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $1.311 million for Campbell Unit 1 and $1.452 million for Campbell Unit 2. The hypothetical capacity value upon which the Company plans its capacity resources (75% of Cost of New Entry ("CONE") for Zone 7 in the 2023-2024 PRA is $19.0 million for Campbell Unit 1 and $21.1 million for Campbell Unit 2.

Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.

A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31, 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity value from the customer's perspective. The major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Capital projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Campbell Unit 3 impact its projected performance?

A. It is anticipated that unit performance will remain relatively consistent with current performance. Based upon the Campbell Unit 3 capital and major maintenance projects discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on Exhibit A-42 (RTB-2), line 3, column (c). During the five-year historical period from 2019 through 2023, Campbell Unit 3 had an actual ROR of 14.29%, as shown on Exhibit A-42 (RTB-2), line 3, column (b).

Q. How is this strategy reflected in the Projected Availability for Campbell Unit 3 in the test year?

A. The Projected Availability for Campbell Unit 3 in the test year is 92.00%, as shown on Exhibit A-42 (RTB-2), line 3, column (e). This Availability for Campbell Unit 3 reflects a projected ROR of 8.00% and a PF of 0.00%, as shown on Exhibit A-42 (RTB-2), line 3, columns (c) and (d). No outages are planned at Campbell Unit 3 for the test year ending February 28, 2026.

Q. How does the Campbell Unit 3 Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 3, column (f), during the five-year historical period from 2019 through 2023, Campbell Unit 3 had an NEV of $347.2 million. The 2023 NEV for Campbell Unit 3 was $29.2 million.

Q. Please quantify the capacity value for Campbell Unit 3.

A. As reflected in Table 2, the Campbell Unit 3 capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $3.5 million and the Campbell Unit 3 hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $51.5 million.

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their projected performance?

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (c). During the five-year historical period from 2019 through 2023, Karn Unit 3 had an ROR of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in the test year?

A. The projected availabilities for Karn Units 3 and 4 in the test year are 72.34% and 71.44%, respectively, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (e). The availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 11.78%, as shown on Exhibit A-42 (RTB-2), line 4, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 1, 2025 and last for 42 days, as reflected on Exhibit A-41 (RTB-1), line 2. The availability for Karn Unit 4 reflects a projected ROR of 18.00% and a PF of 12.88%, as shown on Exhibit A-42 (RTB-2), line 5, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 22, 2025 and last for 46 days, as reflected on Exhibit A-41 (RTB-1), line 4.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 4 and 5, column (f), during the five-year historical period from 2019 through 2023, Karn Unit 3 had a NEV of -$8.1 million and Karn Unit 4 had a NEV of -$10.4 million. The 2023 NEV for each of these units was -$1.7 million and -$0.4 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $1.7 million for Karn Unit 3 and $2.1 million for Karn Unit 4. The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $24.5 million for Karn Unit 3 and $30.9 million for Karn Unit 4.

Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Zeeland Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2019 through 2023, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown on Exhibit A-42 (RTB-2), lines 13 through 15, column (b).

Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in the test year?

A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the Zeeland Plant in the test year is 83.90%, as shown on Exhibit A-42 (RTB-2), line 13, column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability is based upon a projected ROR of 4.0% and a PF of 12.60%, as shown on Exhibit A-42 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for each of the simple cycle generating units at the Zeeland site in the projected test year are 86.79%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, column (e). Each of the Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 9.59%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending February 28, 2026, however there are several shorter duration outages of 10 days each scheduled in May and October. The planned outage for the test year for Zeeland Unit 1 is scheduled to begin on March 10, 2025 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 3. The planned outage for the test year for Zeeland Unit 2 is scheduled to begin on April 21, 2025 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 6. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Zeeland Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 13 through 15, column (f), during the five-year historical period from 2019 through 2023, the Zeeland Plant provided a total NEV of $220.5 million. The 2023 NEV for Zeeland was $49.4 million.

Q. Please quantify the capacity value for the Zeeland Plant.

A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $4.7 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $67.7 million.

Q. Please provide an overview of the generation asset strategy for the Jackson Plant.

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company's generation asset strategy for the Jackson Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on Exhibit A-42 (RTB-2), line 16, column (c). During the five-year historical period from 2019 through 2023, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit A-42 (RTB-2), line 16, column (b).

Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in the test year?

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 81.63%, as shown on Exhibit A-42 (RTB-2), line 16, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 14.52%, as shown on Exhibit A-42 (RTB-2), line 16, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in the test year, however a short 12-day outage is scheduled to begin October 10, 2025. In addition, several derates are scheduled to perform inspections and maintenance on various generating units in April and September 2025.

Q. How does the Jackson Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 16, column (f), during the five-year historical period from 2019 through 2023, the Jackson units provided a total NEV of $158.4 million. The 2023 NEV for the Jackson Plant was $24.1 million.

Q. Please quantify the capacity value for the Jackson Plant.

A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $2.9 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $41.9 million.

Q. How will the Company's generation asset strategy for the Covert Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with past performance under different ownership. Based upon the Covert Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 7.00% for all three units at the Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 17 through 19, column (c).

Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the test year?

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 75.16% to 82.55%, as shown on Exhibit A-42 (RTB-2), lines 17 through 19, column (e). The Covert Unit 1 unit availability of 80.77% is based upon projected ROR of 7.00% and a PF of 13.15%, as shown on Exhibit A-42 (RTB-2), line 17, columns (c) and (d), the Covert Unit 2 unit availability of 82.55% is based upon projected ROR of 7.00% and a PF of 11.23%, as shown on Exhibit A-42 (RTB-2), line 18, columns (c) and (d), and the Covert Unit 3 unit availability of 75.16% is based upon projected ROR of 7.00% and a PF of 19.18%, as shown on Exhibit A-42 (RTB-2), line 18, columns (c) and (d). The Company will conduct major inspections at all three of the Covert Units during the bridge period/test year. The planned outage for the test year for Covert Unit 1 is scheduled to begin on February 1, 2026 and last for 59 days (beyond the test year), as reflected on Exhibit A-41 (RTB-1), line 8. The planned outage for the test year for Covert Unit 2 is scheduled to begin on February 1, 2025 and last for 59 days, as reflected on Exhibit A-41 (RTB-1), line 1. The planned outage for the test year for Covert Unit 3 is scheduled to begin on November 1, 2025 and last for 59 days, as reflected on Exhibit A-41 (RTB-1), line 7. These outages are scheduled for periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Covert Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 17 through 19, column (f), during the seven-month historical period in 2023, the Covert units provided a total NEV of $49.4 million.

Q. Please quantify the capacity value for the Covert Plant.

A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $5.6 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $81.7 million.

Q. Please provide an overview of the generation asset strategy for the River Hydro units.

A. A full discussion of the Company's River Hydro generation asset strategy is included in the direct testimony of Company witness Monroe. In addition, Company witness Monroe will discuss the capital investments for the River Hydro projects which are necessary for continued safe and reliable operation. Regardless of the future of the River Hydro facilities, Consumers Energy will maintain safe operation of its hydroelectric dams as long as they are licensed by the Company. As all of the River Hydro facilities are currently licensed through at least 2034, the Company needs to continue to invest in these assets to maintain its licenses and the Company's commitment to dam safety as long as the Company holds the Federal Energy Regulatory Commission ("FERC") licenses.

Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish any specific requirements for the River Hydro facilities?

A. Yes. Paragraph D on page 309 of the March 1, 2024 Order in Case No. U-21389 required the following:

> "If cost recovery for work on the Hardy Dam is sought in its next general electric rate case, Consumers Energy Company shall file a full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with Federal Energy Regulatory Commission standards, with projected total costs."

As reflected in Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 27, the Company intends to invest $53.854 million in the Hardy Dam Auxiliary Spillway Project in the projected test year with construction beginning in the fall of 2025. Company witness Monroe is supporting the full evaluation of the alternative options for the Hardy Dam in order to remain in Compliance with FERC requirements and its operating license.

Q. What is the status of the requirements included in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224) for the Muskegon River?

A. The Company has fulfilled the requirements reflected in the Settlement Agreement in the Company's 2022 Electric Rate Case (Case No. U-21224). The Settlement Agreement reached in Case No. U-21224 required the Company to "work with Staff and the Attorney General to scope and conduct the following analyses of all reasonable options prior to commencing construction of the Hardy Dam upgrades:

> "a. Economic business cases performed by an outside engineering firm with experience in dam engineering, construction, and decommissioning, that will compare the

> projected capital and O&M costs through the end of Hardy Dam's current Federal Energy Regulatory Commission ("FERC") license term, with the value of the energy and capacity that Hardy Dam will provide customers, under a variety of reasonable assumptions. These assumptions will be inclusive of at least the current long-term forecast for energy prices and replacement capacity priced at a range of percentages of the Cost of New Entry. The business case shall utilize best available assumptions and consider, at a minimum, the feasibility and impacts of (i) divestiture, (ii) permanently lowering the reservoir height, (iii) full decommissioning and removal, and (iv) other options that avoid or minimize the impact of the Hardy Dam on customer rates. In addition, the Company will perform, or cause to be performed, an economic assessment of the impact of each of these scenarios on the Muskegon River Hydroelectric Dam communities.
>
> b. The Company shall engage in discussions with affected local communities on the costs and timing of the proposed Muskegon River Hydroelectric Dam projects, the need for additional funding from those Muskegon River Hydroelectric Dam impacted communities and possible mechanisms for funding to ensure FERC compliance and dam safety at the Hardy Dam, and the impact to the Hardy Dam and reservoir (as well as the Rogers and Croton dams and reservoirs) if this additional funding is not already recovered in Consumers Energy rates or received from other sources. Prior to construction of the Hardy Dam upgrades, the Company agrees to report on these discussions and inform the Commission whether additional funding from the communities or other sources is feasible (both as to amounts and timing) and provide a best-efforts estimate of the total revenue, if any, that could potentially be available from such sources."

Q. What is the status of the Company's progress on the business cases?

A. Consistent with the terms of the Settlement Agreement, the Company has commissioned the performance of business cases for the Muskegon River Hydro facilities (Croton, Hardy and Rogers) by an outside engineering firm that has experience in dam engineering, construction, and decommissioning. The business cases utilized best available assumptions and considered divestiture (as will be discussed later in this direct testimony), full decommissioning and removal utilizing all three decommissioning options, and a permanent lowering of the reservoir height. Confidential Exhibit A-149 (AJM-7) includes the results of the business cases for the Muskegon River Hydro facilities.

In addition, the Company commissioned the performance of an economic assessment of the impact of each of these scenarios on the Muskegon River Hydro facilities communities. The results of these economic assessments are presented in Exhibit A-44 (RTB-5).

Q. Did the Company engage the MPSC Staff and the Attorney General in the development of the business cases and the economic assessments?

A. Yes. The Company met regularly with the MPSC Staff and the Attorney General to review the scope and receive input on both the business cases and the economic assessments. Through a non-disclosure agreement ("NDA"), the Company shared all relevant information related to each of the scope items, met to both present and discuss the inputs, scope, and results of each of the analyses. The Company provided formal responses to interrogatories regarding the process, data, and the results, facilitated a tour of Hardy Dam for the Attorney General, and also facilitated specific discussions on topics such as probable maximum flood ("PMF") to ensure understanding of the Hardy project design was as complete as possible.

Q. What is the status of the RFP for River Hydro divestiture?

A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities on February 15, 2024. The RFP participants will move through a two-stage evaluation and bidding process that is expected to be complete by the end of 2024.

Q. Has the Company received responses from the February 15, 2024 RFP?

A. Yes. As part of the first phase of the RFP, which involves bidder screening based on, among other things, qualifications and indicative pricing, the Company received responses to the RFP on March 15, 2024. The Company has evaluated the bids and moved to the second phase of the RFP in April of 2024.

Q. What is the scope of Phase 2 of the RFP process?

A. Phase 2 involves engaging with seven selected entities in due diligence, negotiations, and potential sale agreement(s). Due diligence will be completed during the summer, and negotiations will take place for the remainder of the year.

Q. What is the status of the Company's discussions with affected local communities and their ability to provide funding to maintain the River Hydros?

A. To identify the potential for community funding, the Company met with local elected officials and other key community stakeholders (chamber of commerce, economic development, homeowners associations, parks department, etc.) at each River Hydro facility. The Company met several times with each community, the first meeting was to introduce the concept of community funding to the community and gauge their interest and initial thoughts on capacity. If favorable, we asked them to spend some time researching the initial options we discussed to better understand their potential capacity for funding.

The Company revisited each community four-to-six weeks later to discuss those options and truly understand the community's capacity to support its operations. At the second meeting the Company did not ask for any commitments. As a result of the meetings, the Company did identify some funding in most communities, but the available funding was not significant when compared to the Company's current gap between relicensing and decommissioning cost estimates.

Q. What are your thoughts regarding the Company's compliance with the requirements of the Settlement Agreement?

A. As a result of the Company's collaboration with the MPSC Staff and the Attorney General, its commissioning of business cases and economic impact studies, and its economic outreach and identification of external funding, it is my opinion that the Company has satisfied the requirements of the Settlement Agreement.

Q. Has the MPSC imposed additional requirements on the Company before moving forward with construction on the Hardy Dam?

A. Yes. The March 1, 2024 Order in the Company's 2023 Electric Rate Case (Case No. U-21389) included the following requirement in ordering paragraph D:

> "If cost recovery for work on the Hardy Dam is sought in its next general electric rate case, Consumers Energy Company shall file a full evaluation of all alternative options and pricing for the work that must be done in order to remain in compliance with Federal Energy Regulatory Commission standards, with projected total costs."

Company witness Monroe addresses this requirement in his direct testimony as the Company has included projected project costs for work on the Hardy Dam in this proceeding.

Q. Please describe the Company's anticipated timeline for deciding whether each River Hydro will be relicensed, sold, or decommissioned.

A. The Company intends to make a decision on the divestiture of the River Hydros by the end of 2024. Should the Company make a decision to not divest the assets, the Company would revisit the decision to relicense or decommission the River Hydros, with the intention of making a decision in the 1st quarter of 2025.

Q. Will the Company's decision affect the need for the River Hydro investments and expenses requested in this case?

A. No. Regardless of the ultimate decision on whether to relicense, sell, or decommission the respective River Hydro facilities, the investments and expenses requested in this case are needed to appropriately maintain those facilities in order to ensure they are safe and legally compliant. The required diligence which needs to be undertaken in order to make a decision on the future of the River Hydros (e.g., adequate evaluation of the bids submitted by the seven entities which are part of Phase 2 of the RFP process and analysis of the community impact study) means that a decision on the future of the River Hydros cannot be reasonably made until late 2024 at the earliest. Subsequent activities to implement the decision(s) will extend into and beyond the test year for this case. The River Hydro investments and expenses requested in this case are needed to reasonably operate those facilities regardless of the ultimate decision on whether to relicense, decommission, or sell one or more of them.

Q. Would it be reasonable to delay approval of the River Hydro investments and expenses requested in this case?

A. No, it would not. Delaying approval of the River Hydro cost recovery in this case would mean denying the Company's ability to execute the investments and operations and maintenance activities necessary to keep the River Hydro facilities safe and compliant with FERC regulations.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (c). During the five-year historical period from 2019 through 2023, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (b).

Q. How do the Ludington Units factor into the Company's future renewable energy strategy as outlined in the IRP?

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio since it can deliver a significant amount of energy in a short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy. However, defective and non-confirming work performed by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully provide these intended benefits over its remaining life.

Q. How is this strategy reflected in the Projected Availability for Ludington in the test year?

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 74.03% to 88.30%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 3.50% and PFs ranging from 8.49% to 23.29%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, columns (c) and (d). There are currently no major outages planned for the Ludington units in the test year; shorter outages on all six Ludington units are scheduled throughout the test period, primarily in the spring and fall. These outages will be used, in part, to evaluate and monitor ongoing issues with the Toshiba work. The outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

Q. Please provide an overview of the generation asset strategy for the Renewable Energy Assets.

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, has been entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement.

Consistent with the IRP, the strategy for the wind assets is to complete construction and have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With respect to solar, the Company plans to continue to add incremental solar resources in accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations, as discussed in more detail later in this direct testimony. In addition, the Company anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027[1] in support of the Company's Voluntary Green Pricing Program, and their costs will be reconciled through the Company's Renewable Energy Plan. The overall investment objective for the Company-owned assets is to provide funding for projects as appropriate to maintain economic dispatch and capacity from the customer's perspective. The Company has a time-based availability target of 97% for its renewable energy wind assets. This availability target considers those periods during which the wind is sufficient to produce energy. The capital expenditures and major maintenance expenses in the plan are targeted to maintain the designed performance level.

Q. How will the enactment of PA 235 of 2023 impact the Company's renewable energy portfolio?

A. As previously discussed in this direct testimony, the Company will be filing a Renewable Energy Plan Amendment no later than November 15, 2024. PA 235 of 2023 has established both renewable and clean energy targets for the future beginning with a renewable energy compliance target of 50% in 2030. The newly passed law became

[1] The Settlement Agreement in the Company's 2021 Renewable Energy Plan Amendment, Case No. U-20984, reflected the addition of up to 500 MW of solar and 500 MW of wind over the period from 2024 through 2027 to support the Company's Large Customer Renewable Energy Program.

effective on February 27, 2024 and provides for the utilization of renewable energy assets from anywhere within the MISO footprint.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-42 (RTB-2), lines 20 through 21, column (f), during the five-year historical period from 2019 through 2023, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of $166.7 million. The 2023 NEVs for Cross Winds Energy Park and Lake Winds Energy Park were $18.6 million and $7.0 million, respectively. As reflected on Exhibit A-42 (RTB-2), lines 22 through 23, column (f), during the two-year historical period from 2022 through 2023, Gratiot Farms Wind and Crescent Wind were provided total NEV of $68.5 million. The 2023 NEVs for Gratiot Farms Wind and Crescent Wind were $9.7 million and $10.7 million, respectively. Heartland Farms Wind Park began commercial operation on January 2, 2024, and as reflected on Exhibit A-42 (RTB-2), line 24, column (f), generated $0.4 million in NEV in 2023 following its December 29, 2023 commercial operation date. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 2023 NEV for its Solar Garden Assets totaled $1,140,655.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $0.8 million and the renewable asset hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $11.2 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Metz provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the electric generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II
ENVIRONMENTAL REGULATIONS
OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

Current (On-going) Environmental Compliance

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company's existing AQCS complies?

A. Yes. In April 2022 the Environmental Protection Agency ("EPA") proposed the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard." The EPA's rule was finalized, effective March 15, 2023. The rule resulted in very little impact to the Company in the short term. The rule does contain a budget re-allocation provision which will ratchet down the nitrogen oxide

("NOx") allowances allocated to the Company, so the Company will continue to monitor the rule and evaluate the various options for compliance.

Q. What are the capital investments and/or O&M expenses the Company is seeking recovery of in this case that are specifically related to air quality control?

A. Any capital and/or O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibits A-12 (RTB-3), Schedule B-5.2 and A-43 (RTB-4).

Q. Are you seeking recovery of any expenses related to the regulation of greenhouse gases from EGUs?

A. No, not at this time. The EPA released proposed greenhouse gas ("GHG") regulations for power plants under Section 111 of the Clean Air Act in May 2023. The proposed regulation covered GHG emissions from existing coal-fired and some existing natural gas-fired units. The rule does not impact the Company's remaining coal-fired units due to the May 2025 retirement date for all coal-fired units. The EPA announced in March 2024 that when the proposed Section 111 rule is finalized, scheduled for April 2024, it will no longer cover existing natural-gas fired units. EPA states that existing natural-gas fired units will be covered in a future regulation.

<u>Environmental Regulations and Compliance Strategy – Waste</u>

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows Department of Environment, Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

Q. What are the capital and/or O&M investments Consumers Energy is seeking recovery of in this case that are specifically related to RCRA compliance and/or overall CCR Management?

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The Cost of Removal ("COR") and/or O&M required for the management of CCRs under the RCRA that the Company is seeking recovery of can be found in Exhibits A-122 (JJK-3) and A-42 (RTB-4). The COR expenses represent historical expenses only. Separately, there are closure activities that will continue throughout the bridge period and test year and beyond; however, those expenses are COR and are not included in this filing.

SECTION III
GENERATION CAPITAL EXPENDITURES
OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation, 2023 through the projected test year - 12 months ending February 28, 2026. Exhibit A-12 (RTB-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2023, the Projected 14-month Bridge Period beginning January 1, 2024 and ending February 28, 2025, and the projected test year beginning March 1, 2025 and ending February 28, 2026. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but is presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically, page 7 of this exhibit presents capital projects for the Historical Period ended December 31, 2023; page 8 of this exhibit presents capital projects for the Projected 14-month Bridge Period beginning January 1, 2024 and ending February 28, 2025; and page 9 of this exhibit presents capital projects for the projected test year ending February 28, 2026.

Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9?

A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type, the generation unit, project type, project classification, project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly; whereas, non-routine projects are typically undertaken once every 10 years or longer. The budget approval reflects the status of internal approval for the project, including projected cost amount. Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost; whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project projected amount.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $859.095 million for the historical test year ended December 31, 2023 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b); $463.548 million in the projected 14-month Bridge Period ending February 28, 2025 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and $600.484 million in the projected test year ending February 28, 2026 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

Q. Has the Company included any contingency in the requested capital expenditures for Generation?

A. No. The Company no longer includes contingency in its generation projects.

Q. Please explain how the Company prioritizes its capital investments within Generation.

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, compliance, and continued operation related projects. These projects are considered a mandatory cost of doing business. Safety, regulatory, compliance, and continued operation-related projects provide economic value to customers in that they allow the units to remain in service and avoid potential derates and/or shutdown due to an intervention by various regulators including Occupational Safety and Health Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis for the investments necessary to satisfy service quality, safety, and Federal and State policy requirements.

Q. How does the Company determine whether other projects get approved for funding?

A. In accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce ROR, maintenance cost or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. In other words, the implementation of the project should, at a minimum, result in a marginal customer benefit.

Q. How does the Company evaluate other capital investments, such as economic projects?

A. The Company uses two financial measures, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects within Generation. A complex financial model was developed in-house that allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units.

Q. Does the Company calculate IRRs or PVRs for all projects?

A. No. The Company calculates IRRs or PVRs for economic projects that are not considered required but would yield net benefits to customers. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and result from a reasonable evaluation of alternatives, but because the project must be done for compliance and continued operation, IRR or PVR may not be calculated. When evaluating project alternatives related to regulatory, compliance, and/or continued operations, IRRs or PVRs may be used to rank alternatives.

Q. Please explain what you mean by projects for continued operations.

A. Projects for continued operations refers to projects which are necessary to allow the generating unit to continue to operate through its retirement date. Alternatives for projects necessary for continued operation will generally be evaluated based upon LCBF. For this evaluation, one of the alternatives will include a decision to not perform the project and either retire the unit earlier than projected or operate the unit at a permanent derate.

Q. How does the Company evaluate customer benefits associated with generation-related capital investments?

A. The Company uses replacement power cost estimates and PSCR impacts when evaluating customer benefits. The Company also evaluates ROR and heat rate improvements, which result in increased and/or lower cost generation.

Q. How does the Company evaluate historical events which have impacted availability?

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending February 28, 2026.

Q. Does the Company evaluate customer benefits associated with Outage Schedules?

A. Yes, the Company uses historical market prices to evaluate timing around outages in an effort to ensure the unit is available during periods in which market pricing is projected to be high.

Q. Is it possible that the Company could experience changes to its scheduled outages and forecasted capital expenditures in the future?

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2023. A review of the outage schedule used in this case identifies eight scheduled outages that begin in March 2025 (18 months after the schedule was approved) and run through

February 28, 2026, 29 months later. During each of these eight scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

Q. Are there other reasons why outage schedule changes occur?

A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices.

Q. Can you provide an example of when circumstances changed?

A. Yes. The Company's fall 2023 outage for Campbell Unit 1 was originally scheduled from October 13, 2023 through November 12, 2023. The unit was placed into economic reserve status on February 19, 2023 and subsequently began a maintenance outage on March 7, 2023. The maintenance outage lasted for 14 days, ending on March 21, 2023. During this timeframe, all priority work scope that was scheduled for the fall outage was completed, obviating the need for the planned outage scheduled to begin on October 13, 2023.

Q. Please describe how the Company determines its generation projected capital expenditure amounts.

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant, and reliable operations of the Company's electric generating fleet. Projected capital investments are informed by historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's electric generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

Q. How are projects identified that are discussed later in this direct testimony?

A. Generation System Planners assess the equipment performance and compare that assessment with the generation asset strategy for the generating unit. Upon identification of a potential project, the Planner will complete a project initiation document ("PID"). This document defines the issue, alternatives considered for resolution, intended benefits or consequences avoided, and suggested timing and a cost estimate. The document is reviewed by multiple groups for alignment and ultimately routed for approval for inclusion in the Long-Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be scheduled three to five years in the future to align with outages and provide the project execution teams ample time to plan and engineer.

Q. How were the projected capital expenditure amounts developed for each of the projects discussed later in this direct testimony?

A. Each project begins with the creation of a PID. The Planner will provide an initial cost estimate for the project within the PID. The Planner utilizes past experience, contractor cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and studies to provide the best estimate of the costs. This activity typically takes place three to five years prior to the start of project execution.

Q. How are PIDs related to Concept Approval Documents ("CADs")?

A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once the project is included in the LTFP and the project is within a year of start of execution, the CAD is created. The CAD is templated from the PID and updated as necessary. The CAD is then routed for approval to the designated level of management based on project amount and, once approved, the project will be initiated.

Q. Do adjustments to the projected capital investment amounts for each of the projects occur prior to project implementation?

A. Yes. As the project team progresses through the life cycle of a project, there are multiple opportunities to better define project costs. Activities such as detailed engineering, bidding, contractor involvement, and construction all allow for budgets to be better defined. As this definition evolves, the projected capital investments are updated accordingly.

2023 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2023 actual capital expenditure amount of $859.095 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21389?

A. The 2023 actual capital expenditure amount of $859.095 million is $430.277 million below the Company's requested amount in Case No. U-21389. The reduction in the Company's actual capital expenditure amount is directly attributable to the removal of the capital expenditures for IRP solar projects and the actual accounting treatment of the Covert purchase. While the Covert total purchase cost was consistent with projections, the total amount was not recorded as an addition to plant in service. The actual amount recorded as capital was $151.858 million less than the projected purchase amount as can be seen on

Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 3, columns (g) and (h). The projected amounts for the 2019 and 2020 IRP Solar Bid Events totaled $355.250 million in the Company's 2023 Electric Rate Case No. U-21389 (see Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 38 and 39, column (n)), however these amounts were removed from the case due to their project status. The projected solar project capital expenditures were not projected to close by the end of the projected test year and were offset by the allowance for funds used during construction ("AFUDC"). As such, the underspend did not impact the revenue requirement. A compilation of the 2023 projects which have actual capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, compare with the 2023 capital projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9?

A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the 2023 projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, reveals that there are seven projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, which were not reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9. In addition, there were twenty projects for 2023 that were reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

Q. Please discuss the 2023 capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, due to the fact that their actual 2023 capital expenditure amount was less than $1 million, the project was disallowed, reduced in cost, or not pursued in 2023. The disposition of these capital projects is provided below:

Below is a list of projects whose projected bridge period costs were disallowed in the final order in Case No. U-21389:

Project Description	Projected Amount
Covert Non LTSA Capital - Extras not included in contract	$ 3,942,510
Karn Tank Farm Storage Tank Heating Line Replacement	$ 1,253,971
Karn Sync Wire Replacement	$ 1,450,000
Alcona Core Wall Remediation Project	$ 1,810,370
Rogers Probable Maximum Flood Project	$ 1,898,708
2019 Solar Bid Event – Mustang Mile	$ 233,064,275
2020 Solar Bid Event – Washtenaw	$ 122,186,164

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21389 were less than $1 million:

Project Description	Projected Amount	Project Reduction
Webber Unit 1 Generator Rewind	$ 1,020,000	$ 1,020,000
Zeeland Milestone Outage Capital to GE - Part of LTSA Contra	$ 7,870,000	$ 7,870,000
Zeeland Unit 4 Field Rewind of Generator Rotor	$ 1,205,357	$ 1,205,357
Zeeland Unit 3 Field Rewind of Generator Rotor	$ 1,205,357	$ 1,205,357
Cooke Spillway Hoist Replacement	$ 2,100,000	$ 1,492,000
Zeeland Phase 2 599 699 345kV Breaker Replacement	$ 1,222,915	$ 773,000
Ludington Oil Water Separator Replacement	$ 1,162,917	$ 679,000
Ludington Unit 1-6 DCS Control Relay Replacement	$ 1,347,516	$ 727,000

Below is a discussion of the remaining million-dollar projects whose actual 2023 capital expenditures were less than projected:

- Zeeland Heat Recovery Steam Generator ("HRSG") Casing Replacement ($2,803,333). This project is scheduled to be completed in 2024. The Company spent a total of $699,676 in 2023 and $2,097,620 is scheduled for the projected bridge period ending February 28, 2025;

- Zeeland Generator Step Up Transformer Replacement (Spare) ($2,883,33). During 2023, the Company spent a total of $758,314 on this project, $589,607 is planned for the bridge period ending February 28, 2025, and $6.449 million is planned for the test year ending February 28, 2026;

- Five Channels Dead Bay and Log Chute Remediation ($1,981,666). This project was completed in 2023; however, the project was entirely a removal project. As such, a total of $2,134,312 was recorded to cost of removal and a negative $331,235 was recorded to capital;

- Ludington Replace Barrier Net Panels ($1,088,614). The Company spent a net total of $705,769 in 2023 as a result of an offset of $747,499 from the Ludington co-owner; and

- Karn Units 3 and 4 Separation ($1,789,545). The separation work was performed in 2023; however, a large portion of the expense was recorded to cost of removal. The Company pursued a separate project (Karn Units 3 and 4 boiler plant heating) as an alternative to upgrading the auxiliary boilers as part of the utility separation. I will discuss that project later in this direct testimony.

Q. Please discuss the 2023 capital projects that were not included in Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is presented below:

- Covert Information Technology ("IT") Room ($2,059,520). The scope of this project was to provide the plant connectivity to the Consumers Energy's SCADA and corporate networks while keeping the plant fully operational during the transition from the legacy network to Consumers Energy networks. The North American Electric Reliability Corporation ("NERC") Critical Infrastructure Protection ("CIP") regulation requires that the SCADA and corporate networks be separate from each other and, due to the legacy network needing to remain operational during the transition, IT required a new IT Room to be built to house the corporate network infrastructure;

- Covert Security and Network ($2,208,169). The scope of this project was to ensure the plant is meeting the physical security requirements for CIP Low assets. Due to the plant having minimal CIP Low physical security assets in place, Consumers Energy's corporate security team was required to install new cameras and card readers throughout the site where all CIP Low assets reside;

- Covert Spare Generator Stepup ("GSU") Transformer ($1,722,987). The scope of this project is the procurement of a spare transformer for the Covert Generating Station. The 2023 capital expenditure reflects a milestone payment to the best identified bidder and internal loadings. This project will be discussed in more detail later in this direct testimony;

- Karn Units 3 and 4 Boiler Plant Heating ($4,836,052). The Karn Units 3 and 4 Plant Heating Boilers Project was a strategic initiative aimed at upgrading the plant heating system at Karn Power Station. The project involved the procurement and installation of two smaller, more efficient boilers for continuous plant heating. Prior to implementing this project, the existing auxiliary boilers were utilized, and the auxiliary boilers were both inefficient and unreliable for continuous plant heating. Originally, the auxiliary boilers were to be used for plant heating and were to be addressed as part of the Karn Units 3 and 4 separation as previously discussed in this direct testimony;

- Karn Unit 3 Exciter Rewind ($1,038,719). The scope of this project was to remove the Karn Unit 3 Exciter Rotor and send it out to be rewound. This work was required as a result of the main lead in the exciter rotor failing open. Once the exciter was disassembled at the vendor facility, the broken lead and the resulting inability to excite was identified. To repair the broken main lead, a full rewind was needed because the main lead was buried under the windings;

- Jackson Multimedia Filtration Pilot Skid ($2,441,755). The scope of this project was to perform testing and calibration as well as provide system improvements to the treatment systems for the well water. The specific scope of the project includes the installation of larger bleach pumps in order to pump a higher flowrate of bleach to counteract the bleach degradation, replacement of caustic pumps on caustic injection system due to issues with pump performance, replacement of variable frequency drive and breaker damaged by caustic injection system, replacement of control valve on well water forwarding pump to increase the flowrate up to the required 1,150 gpm, adjustment of the logic in the reverse osmosis pretreatment system to remove ability for all (4) beds to backwash at the same time, run various scenarios to optimize the throughput of the greensand filters, the caustic in the pretreatment, and the bleach in the pretreatment, and other system improvement activities;

- Zeeland Unit 5 GSU Transformer Rewind ($13,884,854). The scope of this project was to remove the failed Zeeland Unit 5 GSU transformer, movement and installation of the spare GSU transformer, and sending out the failed Zeeland Unit 5 GSU transformer for overhaul which included milestone payments for the overhaul. In addition, the scope reflected the monthly lease of a spare transformer to provided continued operation of the unit for customers. Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned to service on January 23, 2023 upon installation of the leased transformer which was moved from Zeeland Unit 1; and

- Croton 1 and 2 Wicket Gate ($4,329,769). This projected was originally expected to be completed in 2022 however during project implementation a significant amount of additional work was identified during project execution.

PROJECTED 14-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES

Q. How does the projected 14-month bridge period capital expenditure of $464 million compare to the amount of capital approved by the MPSC in Case No. U-21389 for 2024?

A. The 14-month bridge period projected capital expenditure amount of $463.548 million is $5 million less than the projected test year amount of $468.684 million requested in the Company's last electric rate case (Case No. U-21389). The difference between the 14-month bridge amount requested in Case No. U-21389 and the amount requested in this proceeding includes changes in the projects for which recovery is being requested. For example, the inclusion of projected capital expenditures for BESSs is offset by the reduction in projected costs for IRP solar projects. Each of these project areas are discussed in more detail in witness Clark's direct testimony. A compilation of the 14-month bridge period projects which have projected capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. How does the compilation of 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10?

A. A comparison of the 14-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, reveals that there are 26 projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21389, Exhibit

A-12 (RTB-3), Schedule B-5.1, page 8. In addition, there were 17 projects for the 12-month period ending February 28, 2025 that were reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

Q. Please discuss the test year capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than $1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Alcona	Risk Informed Decision Making Resolution	Disallowed in U-21389 Final Order
Cooke	Head Gate Replacement Project	Reflected in Test Year Investment
Covert	Non Long Term Service Agreement Capital - Extras	Disallowed in U-21389 Final Order
Five Channels	Trash Rack Ergonomics Project	Reflected in Test Year Investment
Foote	Unit 2 Wicket Gates Replacement Project	Project Deferred by Company in U-21389
Foote	ADA Ramp Investigation and replacement	Project Deferred by Company in U-21389
Hardy	Electrical Safety Project	Project Deferred by Company in U-21389
Hardy	Hardy Splash Wall Replacement	Disallowed in U-21389 and moved to test year
Hodenpyl	Downstream Wall	Reflected in Test Year Investment
Jackson	LM 1 - 6 SAC Extended Life Combustor	Project Deferred by Company in U-21389
Ludington	Administrative Building Addition	Project Deferred by Company in U-21389
Ludington	Replace Barrier Net Panels	Staff reduced project spend to $0.476 million
Ludington	Intake Gate and Gate House Mechanical Replacement	Staff reduced project spend to $0.700 million
Solar	Solar - 2019 Bid Event (Mustang Mile 150 MW)	Disallowed in U-21389 Final Order
Solar	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Disallowed in U-21389 Final Order
Webber	Unit 1 Generator Rewind	Project Deferred by Company in U-21389
Zeeland	Purchase of Site Spare GSU	Reflected in Test Year Investment

Q. Please identify the 14-month bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9.

A. The bridge period capital projects that were not included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 10, are presented in the table below:

Line No.	Project Description
1	Covert Purchase of site spare GSU
2	Covert Cooling Tower Gearboxes
3	Covert SCR/CO Catalyst Replacement - Unit 2
4	Covert SCR/CO Catalyst Replacement - Unit 3
5	Covert 1-3 Emerson DCS Evergreen
6	Jackson GE LTSA Historical Extra Work Expected
7	Zeeland 2C GSU Rewind
8	Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging
9	Zeeland LTSA - Extras not included in contract (cranes, mobile equipment)
10	Zeeland Long Term Service Agreement - Running Capital Contract
11	Zeeland HRSG Casing Replacement
12	Karn 3 DCS Evergreen
13	Karn 3&4 Sync Wire Replacement
14	Karn 4 Replacement of Ductwork Insulation and Lagging
15	Karn 4 DCS Evergreen
16	LPS - LPEJ Chamber water stop replacement
17	Alcona Artesian Design Study
18	Foote Spillway Hoist Replacement
19	Hardy Auxiliary Spillway Replacement
20	Hodenpyl - Emergency Spillway Project
21	Hodenpyl Spillway Hoist Replacement
22	Tippy - Unit 1 Thrust Bearing Replacement
23	Solar - 2022 Bid Event (Spring Creek)
24	Armstrong BESS (IIJA Grant App)
25	Iosco BESS (IRP)
26	Weadock BESS (IRP)

The basis for projects 1 through 16 will be discussed in more detail later in this direct testimony, the basis for projects 17 through 22 will be discussed in the direct testimony of Company witness Monroe, and the basis for projects 23 through 26 will be discussed in the direct testimony of Company witness Clark.

Q. Is the projected capital expenditure amount of $463.548 million for the 14-month bridge period ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (e), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (h), $249.572 million of that capital will fund solar projects pursuant to the Company's IRP, $39.672 million will fund BESS projects, $118.854 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $10.279 million will fund various projects at the LPS facility, and $42.376 million will fund various hydro safety, reliability, and regulatory compliance projects. With the exception of the solar, BESS, and the River Hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The River Hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $600.484 million for the test year ending February 28, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (f), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (j), $275.959 million of that capital will fund solar projects pursuant to the Company's IRP, $78.921 million will fund BESS projects, $134.664 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $15.587 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019 and $92.258 million will fund various hydro safety, reliability, and regulatory compliance projects. Except for the solar projects and the River Hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The River Hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

<u>Campbell Units 1, 2, and 3</u>

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for Campbell Units 1, 2, and 3.

A. The Company does not plan to invest any capital in the Campbell units during the bridge period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1 and 8. As presented on Exhibit A-43 (RTB-4), lines 1 and 2, and as discussed later in this direct testimony, the Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025.

Covert Plant

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for Covert.

A. The Company plans to invest a total of $34.087 million in the 14-month bridge period and $61.483 million in the test year at the Covert Plant. These capital investments will be facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025 as well as longer unit outages for major inspections. Covert Unit 1 has a 58-day outage scheduled to begin on February 1, 2026, Covert Unit 3 has a 59-day outage scheduled to begin on November 1, 2025, and Covert Unit 2 has a 58-day outage scheduled to begin on February 1, 2025.

Q. Please explain the Company's projected capital investment for the 14-month bridge period ending February 28, 2025 for the Covert Plant.

A. The Company plans to invest a total of $34.087 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected $34.087 million capital investment in the 14-month projected bridge period?

A. The projected $34.087 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Six of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 6. The basis for these six projects is described below:

- Purchase of site spare GSU (1,000,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Cooling Tower Gearboxes ($1,161,732). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Selective Catalytic Reduction ("SCR")/Carbon Monoxide ("CO") Catalyst Replacement - Unit 2 ($1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- SCR/CO Catalyst Replacement - Unit 3 ($1,041,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Covert Units 1 through 3 Emerson Distributed Control System ("DCS") Evergreen ($1,041,250). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and

- Covert Plant Long-Term Service Agreement ("LTSA") ($20,400,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than $1 million, but are important to reliability:

- Covert Plant (Units 1, 2, and 3) LTSA extra work ($1,748,333 total). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;

- Excitation Replacement ($340,000). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Office Space Consumers Energy Warehouse with Loading Dock ($493,333). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Plant Replace Sulfuric Sodium Hypo and Building ($410,000). The Sodium Hypochlorite system is original, in poor condition, and has experienced multiple failures, creating a safety hazard for the operators. Additionally, this equipment is housed in the same building as the sulfuric acid dosing system with only a fiberglass dividing wall. If both systems were to experience a leak at the same time, that situation could generate poisonous chlorine gas;

- Gas Turbine Generator ("GTG")/ Steam Turbine Generator ("STG") Replace Covert Units 1 through 3 Rollup Doors ($535,000). The Covert Plant faces a significant operational challenge due to the absence of overhead roll-up doors on the south side of the power block building. This infrastructure limitation necessitates the removal of building panels to facilitate the ingress and egress of large equipment, such as STGs and GTGs, during major outages. This project will install insulated rollup doors with electrical power. By installing insulated roll-up doors, the Covert Plant can eliminate the time-consuming and costly process of panel removal and reinstallation. This upgrade streamlines access for large equipment, reducing downtime and associated labor costs. In addition, the insulated design and weather stripping of the Model 625 doors provide significant protection against cold air infiltration, safeguarding critical equipment during outage periods in cold weather;

- Netmation (Operating System & 4S) - Unit 2 ($391,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Netmation (Operating System & 4S) - Unit 3 ($300,833). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Gas Compressor Controls Replacement (Programmable Logic Controller ("PLC") replacement) ($424,4000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface ("HMI") (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;

- Covert Units 1, 2, and 3 – MV90 Revenue Meters for MISO ($570,000). The scope of this project is the replacement of the existing meters utilized to record power flows for purposes of reporting to MISO for market settlement;

- Linear Variable Differential Transformers ("LVDT") Positioning Sensor – Unit 1 Fuel Control Valves ($737.930). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert Base Outage Capital ($443,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

- Twenty additional projects at Covert totaling $1.650 million which support safety, security, and reliability, with each project representing $201,667 or less in capital expenditures. These projects include load commutated inverter Replacements, Unit 2 Power Distribution Center ("PDC") Battery Replacement, Electronic Overspeed protection, site small capital, LVDT Positioning Sensor – Unit 2, and SCR/CO Replacement - Unit 1.

Q. What is the basis for the projected $61.483 million capital investment in the projected test period?

A. The projected $61.483 million capital investment in the projected test period will fund numerous projects at the Covert Plant. Ten of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 10. The basis for these projects is described below:

- Purchase of site spare GSU transformer ($4,500,000). Covert Generating Station consists of three gas turbine powered plants and three steam turbine powered plants placed in a one-on-one combined cycle configuration. The units transmit their power to the grid via GSU transformers. Each gas turbine powered unit feeds the secondary winding of a three-winding transformer, while the associated steam powered unit feeds the tertiary winding of the transformer. The GSU is rated for 500 MVA with forced oil and forced air. If a GSU were to fail, then the associated turbines would not be able to transmit power and would not be able to generate market value for Consumers Energy and its customers. The lead time for a GSU is currently three-to-four years and spare units at other facilities typically do not exist, especially for this more unique design application;

This project provides a spare GSU for Covert which: 1) Greatly reduces unit downtime in the event of GSU issues or failure requiring removal and lowers the total financial losses in such events; 2) Allows for easier engineering design and planning to install a spare or replacement GSU ahead of any emergent installation needs; 3) Mitigates potential issues from installing GSUs not specifically designed for this location, system or application and/or doing it multiple times in a short time period; 4) Would allow for Consumers Energy to enter lease agreements with other utilities who may be in need of a spare to recover some costs of the spare purchase over time; and 5) The oil analysis of Covert transformers revealed the presence of chemicals for corrosive sulfur. Mitigating actions are being taken, however, this failure mode puts these transformers at increased risk of failure;

- Office Space Consumers Energy Warehouse with Loading Dock ($1,816,667). The scope of this project is to build out the existing warehouse and add a loading dock. The existing warehouse does not meet the needs for the upcoming major outages, or plant maintenance in the future. The addition of a loading dock will provide for safer and efficient loading/unloading of trucks. In addition, the current onsite office space is inadequate, and it will be expanded;

  Cooling Tower Gearboxes ($1,039,192). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters;

- Netmation (Operating System & 4S) - Unit 2 ($1,458,333). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture;

- Covert Units 1 through 3 Emerson DCS Evergreen ($2,448,750). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation DCS. The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the current version. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under NERC CIP requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing end of support and requires updating to allow support of the latest Ovation versions.

The Balance of Plant ("BOP") control is achieved with the Ovation DCS. Its architecture is comprised of controller and operator "drops" (processors and PCs) that provide the control of the equipment with input/output ("I/O") modules. Some of these I/O modules are in the same electrical cabinets that contain the "controller drops" (processors). Other I/O is in "remote" electrical cabinets, away from the "controller drops." The existing plant control is comprised of many remote I/O cabinets throughout the site. The communication modules to these cabinets have experienced failures in the past that can trip the generating units offline. Power supplies in the Ovation cabinets have reached the end of their recommend life and need to be replaced. The architecture and components need to be upgraded and replaced with the latest Ovation design.

The main controller drop that operates a large part of the BOP equipment has had equipment and data link controls added to it over the years. It controls equipment for all three (3) generating units. The controller drop needs to have part of its I/O and logic split off to new controller drops. The partitioning of I/O to other drops should allow the upgrade and maintenance procedures to occur and reduce the need of a site outage to perform these activities. Risk to unit trips should be reduced to individual generating units instead of all units on the site;

- Netmation (Operating System and 4S) – Unit 3 ($1,504,167). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture;

- Covert Plant LTSA ($14,700,000). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an Effective Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. During the bridge period and test year, the Company will be conducting major inspections on all three generating units, and a portion of the work to be performed is not covered in the LTSA, rather it is covered in the LTSA extra work as described below;

- Covert Unit 1 LTSA extra work ($1,437,717). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection for Covert Unit 1 begins on February 1, 2026, just prior to the end of the test year, and ends on March 31, 2026. As such, a large portion of the LTSA extra work will not be requested in this proceeding;

- Covert Unit 2 LTSA extra work ($12,609,633). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection on Covert Unit 2 begins on February 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope of work; and

- Covert Unit 3 LTSA extra work ($10,609,633). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection on Covert Unit 3 begins on November 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with MEPPI does not cover this scope of work.

The following projects are less than $1 million, but are important to reliability:

- Excitation Replacement ($761,667). The scope of this project is the replacement of the steam turbine exciters. The existing excitation equipment is obsolete, and the gas turbine exciters have already been replaced. A failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found with a typical lead time of 18-24 months;

- Electronic Overspeed protection ($678,333). The scope of this project is the installation of an electronic overspeed trip upgrade. The plant has experienced issues with their overspeed trip device in the past. The backup electronic overspeed trip is reliable but is not redundant so that a single component failure would not disable the trip. The primary protection on the steam turbines are the mechanical overspeed trip mechanisms. The mechanical overspeed trip mechanism must be tested (offline) periodically to ensure that its setpoint has not changed and that it can trip the unit;

- Flame Detectors for Gas Turbine Wheel temperature Digital replacement ($397,083). The scope of this project is to replace the existing mechanical flame detection system with digital flame detection system. The existing system is obsolete and has reliability issues that a new digital system would resolve;

- SCR/CO Catalyst Replacement - Unit 2 ($708,333). The scope of this project is the replacement of the catalyst for the SCR. This replacement is based upon the expected degradation of the exiting catalyst and effective operation of the SCR is required to meet environmental regulations;

- SCR/CO Catalyst Replacement – Unit 3 ($708,333). The scope of this project is the replacement of the catalyst for the SCR. This replacement is based upon the expected degradation of the exiting catalyst and effective operation of the SCR is required to meet environmental regulations;

- Netmation (Operating System and 4S) – Unit 1 ($375,000). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, I/O modules, servers, workstations, network switches, and software to the latest architecture;

- Balance Of Plant Valves – Unit 2 ($590,000). The scope of this project is the repair and/or replacement of balance of plant valves. The plant has a long list of valves that require attention. The condenser bypass valves will be addressed in the major outage scheduled for March 1, 2025 through March 31, 2025 and they represent a large expense;

- Balance Of Plant Valves – Unit 3 -($590,000). The scope of this projects is the repair and/or replacement of balance of plant valves. The plant has a long list of valves that require extensive maintenance. The condenser bypass valves will be addressed in the major outage scheduled for November 1, 2025 through December 30, 2025 and they represent a large expense;

- Positioning Sensor – Unit 3 ($687,500). The scope of this projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main “A” pressure control fuel valve sensor, Main “B” pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism. The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- SCR/CO Catalyst Replacement – Unit 1 (891,667). The scope of this project is the replacement of the catalyst for the SCR. This replacement is based upon the expected degradation of the exiting catalyst and effective operation of the SCR is required to meet environmental regulations;

- Covert Base Outage Capital ($383,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- LVDT Positioning Sensor - Unit 2 (645,833). The scope of this projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

  The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors; and

- Eighteen additional projects at Covert totaling $1.941 million which support safety, security, and reliability, with each project representing $408,333 or less in capital expenditures. These projects include BOP Valves - Unit 1 MI, Unit 1 and Unit 3 PDC Battery Replacement (NERC), Load Commutated Inverter replacements, Gas Turbine - Units 1 through 3 Evaporator Media, and site small capital.

<u>Karn Units 1 and 2</u>

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 14-month projected bridge period ending February 28, 2025 or the projected test period ending February 28, 2026, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

<u>Karn Units 3 and 4</u>

Q. Please explain the Company's projected capital investment for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026, for Karn Units 3 and 4.

A. The Company plans to invest $17.119 million in the projected bridge period and $7.287 million in the projected test period, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected $17.119 million capital investment in the 14-month projected bridge period?

A. The projected $17.119 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are six projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 14 through 19.

Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish any specific requirements for any of the Karn site projects?

A. Yes. Paragraph C on page 309 of the March 1, 2024 Order in Case No. U-21389 required the following:

> "Consumers Energy Company shall file in its next general electric rate case an alternatives analysis addressing the replacement of the Karn Unit 3 Cooling Tower internal structure, including information on the most cost-efficient solution and alternatives to full replacement as described in this order."

Q. What is the scope of the project?

A. The scope of this project is the replacement of the structural timbers, remaining stacks, and fan blades on Karn Unit 3's cooling tower. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. The entirety of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031. The projected cost for this project in the 14-month bridge period is $6.0 million.

Q. Has the Company performed an alternative analysis?

A. Yes. The Company has created a concept approval to document its evaluation of the project and the potential alternative. The concept approval is presented as Exhibit A-45 (RTB-6).

As established in Exhibit A-45 (RTB-6), the cooling tower internal structure was in poor condition and viable options were limited.

Q. Please discuss the basis for the remaining projects for Karn Units 3 and 4.

A. The basis for the remaining projects greater than $1 million are described below:

- Karn Units 3 and 4 Sync Wire Replacement ($1,260,000). The scope of this project is the replacement of the existing copper communication cables between the plant and Hampton Substation. The replacement will consist of fiber optic communication cable from Hampton Substation to the plant and the replacement of Karn Units 3 and 4 generating unit line protection relays, pilot wire differential line protection relaying, telemetry, and control communication at Hampton Substation. Telemetry and control include but are not limited to breaker position indication, breaker control, transfer trip, bus voltage, and current indication. The Karn Units 3 and 4 auto-synchronizing relay is obsolete. This project will provide a modern reliable communication medium between Karn Units 3 and 4 and Hampton Substation, where the generator synchronization breakers reside. This medium will allow for a reliable means of communication between Karn Units 3 and 4 and the Hampton Substation, thereby reducing the risk of possible failure of the units to synchronize correctly or to trip the units offline for a fault event; potentially causing damage to the generator and turbine, resulting in decreased plant reliability and increased expense;

- Karn Units 3 and 4 Plant Heating Boiler ($1,760,000). The scope of this project is the continuation of the installation of boilers for heating Karn Units 3 and 4. The remaining work to be accomplished in the bridge period includes the following:

  1. Installation of Gas Regulators which required modifications to the already installed gas piping;
  2. Installation new Steam Check Valve;
  3. Conduct Preliminary Air Check prior to hydro to identify any leaks before the State Boiler Inspector was on site;
  4. Install Sump Drains at multiple locations;
  5. Replace Day Tank Steam System Valves;
  6. Install additional Steam Traps;
  7. Install stack extension and stack drains;
  8. Install additional heat trace and insulation; and
  9. Install enclosure around Deaerator.

  The Plant Heating Boilers Project is a strategic initiative aimed at upgrading the plant heating system at Karn Power Station. The project involves the procurement and installation of two smaller, more efficient boilers for continuous plant heating. Prior to implementing this project, the existing auxiliary boilers were utilized, and the auxiliary boilers were both inefficient and unreliable for continuous plant heating. Originally, the auxiliary boilers were to be used for plant heating and were to be addressed as part of the Karn Units 3 and 4 separation as previously discussed in this direct testimony;

- Karn Unit 3 Combustion Air Heaters ($2,200,000). The combustion air heaters A and B had excessive tube leaks that were pressure tested and plugged during the fall 2022 outage. The B section has the worst damage with an estimated 50% of the tubes out of service. The scope of work for this project includes the replacement of two sections of the combustion air heater. The heater condition is causing a 68 MW derate on the unit;

- Karn Unit 4 DCS and Simulator Upgrade Evergreen ($1,363,000). This project replaces the Karn Unit 4 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2015 and software upgraded in 2019. This Evergreen will replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades, the controller drops, and rack-mounted servers will be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates; and

- Karn Unit 3 DCS and Simulator Evergreen ($1,507,000). This project replaces the Karn Unit 3 Ovation DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2019. This Evergreen will only replace the existing Ovation Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and provide recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates.

The following projects are less than $1 million, but are important to reliability:

- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft ("ID") Fans to Stack ($710,667). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;

- BOP Capital tooling/valves/instrumentation ($933,333). This project spans the 14-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;

- Karn Units 3 and 4 - 250v Battery Bank Replacement ($360,000). Replace the 250V battery with an equivalent and replace the charger with greater ampacity to handle full load if batteries die. New battery bank will make Karn Units 3 and 4 more reliable and safer to operate. New battery bank and battery charger will be in operation until the retirement of Karn Unit 3 and 4. New battery bank will improve availability of backup DC bearing and seal oil pumps. Karn Units 3 and 4 utilizes a 250-volt battery bank to run emergency bearing oil pumps & seal oil pumps in case of an emergency, like loss of AC power while the turbine is hot. The 250-volt Battery bank was installed in 2014. Design life of these batteries is approximately 10-12 years. The current batteries are rated for 910 amp hours. Based on the historical data, the 250-volt battery bank has been depleted/discharged a number of times. This has caused battery cells to operate/perform beyond their duty. A load test was conducted on this battery bank in 2022 and the results were marginal. A battery bank can serve the worst-case scenario load for approximately one hour only, which is less than the Company's recommended time for the turbine generator to come to stand still;

- Karn Unit 4 voltage regulator ($400,000). The scope of this project is the installation of a "Digital Front End" upgrade to the GE Automatic Voltage Regulator on Karn Unit 4. The existing voltage regulator was installed around 2004 and was phased out of production in 2011. It became legacy equipment on March 1, 2021 and is no longer available. The software used to configure the existing system runs on Windows XP and is no longer patched or supported. The hardware will be upgraded from EX2100 to EX2100e architecture. This also includes ethernet switches, operator interface, GE project management, operation manuals, drawings, technical direction of installation and design package. Post maintenance testing and MOD-26 testing are also being included; and

- Five additional projects at Karn Units 3 and 4 totaling $0.625 million which support safety, security, and reliability, with each project representing $310,000 or less in capital expenditures. These projects include rewind of the Karn Unit 4 house service air compressor motor, replacement of the processors for the Karn Unit 3 automatic voltage regulator, Karn Units 3 and 4 tank farm storage tank heating line replacement, Karn Units 3 and 4 plant heating boilers, and replacement of the Karn Units 3 and 4 stack ladder fall protection system.

Q. What is the basis for the projected $7.287 million capital investment in the projected test period?

A. The projected $7.287 million capital investment in the projected test period will fund five projects. Two of these projects are greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 18-19. The basis for these projects is described below:

- Karn Unit 4 Replacement of Ductwork Insulation and Lagging ($4,800,000). The scope of this project is to replace the lagging and insulation on all the ductwork from the building out to the stack. The existing lagging and insulation needs to be removed, the underlying steel fixed as necessary, and new insulation and lagging installed. The steel structure that the ductwork lagging is attached to is severely corroded. This has allowed multiple random failures of the lagging, resulting in a safety concern due to pieces of lagging falling to the ground or becoming airborne during wind events; and

- Ductwork Expansion Joint Replacement – ID Fans to Stack ($1,900,000). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance.

The following projects are less than $1 million, but are important to reliability:

- Capital tooling/valves/instrumentation ($500,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year; and

- Two additional projects at Karn Units 3 and 4 totaling $0.087 million which support reliability, with each project representing $66,667 or less in capital expenditures. These projects include overhaul of the Karn Unit 4 condenser circulating water pumps and project closeout of Karn Units 3 and 4 sync wire replacement.

<u>Zeeland Plant</u>

Q. Please explain the Company's projected investment for the 14-month projected bridge period ending February 28, 2025 and projected test year ending February 28, 2026 for the Zeeland Plant.

A. The Company plans to invest $48.518 million in the 14-month projected test period and $50.929 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by short outages in the spring and fall of the 14-month projected test period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected $48.518 million capital investment in the 14-month projected bridge period?

A. The projected $48.518 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 9 through 13. The basis for these projects is described below:

- Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($20,356,250). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;

- Zeeland Plant LTSA ($9,520,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;

- Zeeland Unit 5 GSU Rewind ($5,546,538). The scope of this project will remove the failed Zeeland Unit 5 GSU transformer and send it out for rewind and overhaul to support long-term reliable operation. This project also installs a leased GSU transformer. The Zeeland Unit 5 GSU Transformer, which outputs electricity from the generator to the grid, was showing signs of imminent failure as indicated by hydrocarbon gasses being continuously generated at rates above Institute of Electrical and Electronics Engineers (IEEE) recommended levels. The time to failure could not be predicted and could have been catastrophic in nature. Previous intrusive internal inspection and testing work in fall of 2022 was able to identify and replace some degraded parts but ultimately not able to locate the source of gas generation;

- Zeeland Plant HRSG Casing Replacement ($2,097,620). The HRSG is designed to recover and recycle heat energy from a gas turbine exhaust. A HRSG produces steam that is used to drive a steam turbine. During recent inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion has been identified in particular sections of the units. This condition creates the risk of the studs, which hold on the insulation and liner panels, breaking loose and liberating both insulation and liner sheets. The insulation then blows downstream and fouls the HRSG tubes, requiring the unit to be shut down and cleaned, then subsequent casing, insulation, and liner repairs. The affected areas of casing need to be cut out and replaced with new casing; and

- Zeeland Plant LTSA supplementals not included in contract ($3,925,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Main Steam Non-return Valve Replacement ($705,309). The scope of this project is to replace both main steam check valves. During inspections in the Fall 2018 outage, cracking was noted on both of the main steam stop-check valve body internals. With continued plant operation, the cracks are expected to continue to grow, potentially extending through the valve seat, making the valve unable to seal completely. The cracks can also grow to a through-wall crack, resulting in a steam leak. This cracking is a known issue with these types of valves, and is driven by expansion differentials primarily on startup and shutdown. This cracking had initially been noted during a pipe borescope inspection in 2011;

- Zeeland - Purchase of Site Spare GSU Transformer ($589,607). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;

- 199 and 499 345kV Breaker Replacement ($623,483). The scope of this project is to replace the 199 and 499 circuit breakers with a type which does not exhibit the failure modes exhibited by the existing design. The existing breakers have a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland Substation, and/or equipment damage;

- Site Commons Road Resurfacing ($554,167). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;

- Gas Turbine Inlet Filters Replacement ($390,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;

- ZGS – GE DCS Evergreen ($600,000). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson PWCS application. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches;

- ZGS – 299 345kV Breaker Replacement ($510,000). The scope of this project is to replace the 299 circuit breaker with a type which does not exhibit the failure modes exhibited by the existing design. The existing breaker has a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or equipment damage;

- Zeeland Plant Base Outage Capital ($482,555). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and

- Seventeen additional projects at the Zeeland Plant totaling $2.617 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $337,200 or less in expenditures. These projects include Install Combustion Turbine Overspeed Software, Phase 2 599 and 699 345kV Breaker Replacement, Zeeland combined cycle GT2A GT2B Air Filter Replacement, MarkVIe Controller Replacement Project, 480V Circuit Breaker Coordination System Replacement, CT Autotune Software Replacement, boiler feedwater pump, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $50.929 million capital investment in the projected test year?

A. The projected $50.929 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are six projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 12-17. The basis for these projects is described below:

- Zeeland Plant LTSA ($8,181,333). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-site technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help minimize ROR and it will optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Zeeland Plant LTSA supplementals not included in contract ($4,275,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Zeeland Site Spare GSU Transformer ($6,449,004). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently three-to-four years and spare units at other facilities are not viable replacements due to compatibility and installation challenges. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future. As previously discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent out for rewind;

- Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($25,743,740). The scheduled Major Inspection outages in 2025 for the Phase 1 gas turbines at Zeeland Generating Station present an ideal time for substantial technological advancements. This project proposes the integration of Advanced Gas Path ("AGP") and Axial Fuel Staging ("AFS") technologies during these outages, aimed at boosting turbine performance and operational flexibility. A more detailed analysis of this project is presented in Exhibit A-46 (RTB-7): Zeeland Phase 1 Gas Turbine upgrades;

- Generator Rewinds ($2,174,167). There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life; and

- Phase II Turbine Replacements ($1,884,167). The scope of this project replaces the existing rotor with a new rotor, giving another 144,000 hours of operation which would enable operation until the next rotor replacement out to approximately the year 2045. Also included in this scope is new compressor stator vanes due to the compressor being 20 years old; the best way to restore the compressor to like-new condition is to replace the stationaries when the blades will already be replaced. Lastly, the exhaust frame will be upgraded to a robust exhaust frame due to reliability issues over the years, and the rotor replacement being an appropriate time to replace the exhaust frame.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Zeeland combined cycle SCR Catalyst Replacement ($417,500). The scope of this project is to replace the SCR catalyst to maintain NOx reduction on gas turbine emissions;
- Site Commons Road Resurfacing ($395,833). The scope of this project is to perform continued resurfacing of site roads. Several roads require widening to ensure safe 2-way vehicle travel (e.g. road behind substation). Roads/driveways on site require continuous maintenance. The objective of the project is to ensure roadways are safe for both vehicle and pedestrian travel;
- Zeeland Plant Base Outage Capital ($424,444). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during unit outages; and
- Nine additional projects at the Zeeland Plant totaling $0.984 million support reliability and operations, with each project representing $241,667 or less in expenditures. These projects include Unit 5 Battery Replacement, Phase II Unit 3 and 4 battery monitoring system, compressed air system replacement, boiler feedwater pump replacement, and small pumps, motors, valve, instrumentation, tools, and equipment.

Jackson Plant

Q. Please explain the Company's projected investment for the 14-month bridge period ending February 28, 2025 and test year ending February 28, 2026 for the Jackson Plant.

A. The Company plans to invest $19.130 million in the 14-month projected bridge period and $14.965 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the fall of 2024 and 2025. The Company has a LTSA with GE to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected $19.130 million capital investment in the 14-month projected bridge period?

A. The projected $19.130 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 7-8. The basis for these projects is described below:

- Jackson Plant LTSA ($12,337,500). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and

- Jackson Plant LTSA Extra Work ($2,908,333). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Feedwater Desuperheater Valve Replacement ($831,433). The scope of this project is to install feedwater control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously. The HRSG 1-6 superheat ("SH") Steam Desuperheater Feedwater valves have had very short life spans since original construction. There are several issues that cause the valves to wear out quickly. The valves inherently cycle frequently open and closed due to the boiler running close to high pressure ("HP") Steam Outlet temperature setpoint at gas turbine baseload, without duct firing. This has been reduced recently by a study completed by engineering and GE to allow the HP Steam temperature to be increased from the original 750 degrees Fahrenheit up to 770 degrees Fahrenheit. This change did cause the valves to cycle open/close less frequently, but it did not result in a substantial improvement in valve life. The brunt of the wear is absorbed by the HP FW Autoblock valve, which when it begins to leak by, causes the SH Steam temperature to fall. The HP FW Control Valve wears out quickly as well. Typically, when this occurs the leak by accelerates quickly to the point which the manual HP FW isolation valve upstream must be closed when the unit is not duct firing in order to maintain adequate superheated steam temperature;

- LM6000 Beckwith Relay Replacement ($391,667). The scope of this project seeks to replace the LM6000 Generator Protective Relays with direct replacement relay upgrades and install test facilities in a pre-planned fashion. This will protect the generation assets and avoid issues with the obsolescence of the existing equipment. Jackson Units 1 through 6 are currently protected with Beckwith M3420 Relays that are obsolete. The long lead time replacement M-3425A relays have been purchased, and are awaiting installation.

  In addition to being obsolete, the existing relays have limited, or no means for communication, fault analysis, troubleshooting, and event recording following an electric fault event. The current relays also do not have external test facilities for periodic maintenance. Because of this, the relays need to be un-wired to test, and then rewired. This increases maintenance time, as well as exposes the plant to unplanned operations due to human error;

- Base Outage Capital ($350,000). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Site 480V Breaker (WavePro) Replacement ($267,000). The 480V circuit breakers each have a small control box that senses the amount of current thru the breaker and trips the breaker for a fault. These trip modules have electronic components normally expected to last 10 years, and some are presently failing after 20 years of service. Since these trip modules are no longer made, a failure requires complete replacement of the module and current sensors at a qualified breaker repair shop. The scope of this project is to replace all 30 trip modules;

- Units 1-6 LM HP Start-up Vent Silencer Replacement ($248,000). The degradation of the existing LM HP Start-Up Vent Silencers (original to plant) has resulted in exceeding the noise level limitations set forth in ST-001, Standard Technical and Site Data Specification. The specification states that the equipment shall not exceed 90 dBA when measured three feet from vent silencer opening at 90 degrees to the flow. The noise levels are disruptive to the surrounding neighborhood in addition to plant personnel. The replacement of three silencers will reduce the noise of current silencers, prevent additional excessive noise for plant personnel (OSHA) and surrounding community safety, and proactively avoid risk of violating city ordinances;

- JGS – Low Quality Sump Piping Replacement ($256,535). The Jackson Plant has three sump pits to deal with wastewater throughout the plant. One of these sump pits is called the water treatment low-quality ("LQ") sump, one the main low-quality sump, and one is the high-quality ("HQ") sump. The water treatment LQ sump deals with most of the wastewater that comes from the plant including reverse osmosis backwash discharge, floor drains and miscellaneous sources. The main LQ sump takes transformer secondary containment drains. The HQ sump handles blow down condensate from the running units. Each sump pit has two pumps that operate off a multi-float switch level indicator. The level indicators are reaching end of life. The water treatment LQ pumps have a mean time between failures of about one year. The HQ sumps were upgraded in 2019 with no failures at this time. The failures on the water treatment sumps are due to failed bearings, worn impellers, volutes, and casings. There is a large amount of dirt, oil, and other debris that get into the water treatment LQ sump leading to wear of pump components and bearing failures. The scope of this project is to replace the two sump pumps in the water treatment LQ sump and the level indication on both LQ sumps. It is recommended to install pumps with upgraded wear materials to help with the erosion issue and install sealed greased bearings. The level transmitters are also beginning to fail as the switches do not always actuate when they are supposed to. The level transmitters will be replaced with radar level transmitters. The sumps are locally controlled with an audible alarm. This project would also bring control and level indication into the DCS for the sump;

- JGS NOx Umbilical Replacements ($300,728). The scope of this project is to replace the heated sample line (umbilical) on Jackson Units 1 through 5 and 7 from the analyzer to the stack probe. The Continuous Emissions Monitoring System ("CEMS") and associated umbilicals have been in service since 2002. As a result of the heat trace failure on the LM6 umbilical in 2020 and the visual condition of the polyurethane jacket, the remaining umbilicals were inspected. Similar cracking and poor installation practices were observed. To avoid unit downtime in the future, the Company determined that a project should be initiated to replace the remaining units' umbilicals. A three-year implementation plan, replacing two umbilicals per year, is proposed to mitigate risk. The new umbilicals will utilize a PVC jacket that is more resistant to degradation and chemical attack. Post maintenance testing will be required upon replacement including a relative accuracy test audit ("RATA") to recertify the CEMS. The combined-cycle combustion turbines at Jackson are subject to specific NOx emission limits and monitoring requirements originating from several environmental rules. For purposes of demonstrating compliance with the NOx emission limits, JGS relies upon CEMS for each unit;

- Jackson Combustion Turbine Inlet Canister Filter Replacement ($230,000). The Jackson Plant is comprised of nine generating units. Jackson Units 1 through 7 draw combustion air in through a filter house which has integrated filters to prevent dust, dirt, and debris from being pulled into the compressor section of the turbine. The canister filters require periodic replacement to maintain proper air flow to the engine. Over time the filters plug and reduce the efficiency of the combustion turbine. If air flow is restricted enough, the engine can stall due to lack of sufficient air causing catastrophic failure; and

- Twelve additional projects at the Jackson Plant totaling $1.009 million, with each individual project representing $262,500 or less in expenditures. These projects include LM1-6 VIGV (variable inlet guide vane) Project, Major Motor and Pump Replacements, site small capital, DCS Evergreen replacement, and LM1-6 Steam injection trap replacements.

Q. What is the basis for the projected $14.965 million capital investment in the projected test year?

A. The projected $14.965 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There is one project which is greater than $1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 11. The basis for this project is described below:

- Jackson Plant LTSA ($11,116,875). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Jackson Plant LTSA Supplemental Work ($350,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Base Outage Capital ($300,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- JLM1-6 Variable Inlet Guide Vane ("VIGV") Project ($900,000). This project will install new VIGV systems on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC engine has a partial installation already, and the project will complete the VIGV system for this engine. For LM6000PC SPRINT gas turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel efficiency improvement at part power. The average fuel efficiency improvement at 70% of maximum power is greater than 2%. The VIGV also helps minimize variable bypass valve ("VBV") flow and pressure levels, thereby reducing associated flow noise. The VIGV system improves performance for both simple cycle and heat-recovery cycles when operating at less than full load;

- GSU Transformer Site Spare ($833,333). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure to delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three-to-four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell, Karn, Lake winds, and Crosswinds do not have the correct voltage (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to function at Jackson so they cannot be considered for use as spares;

- DCS Evergreen replacement ($666,667). This project replaces the GE DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. (Standard practice is to replace virtualized system hardware every eight years to reduce costs.) The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems (O/S) are on a limited life basis, and they reach the end of "extended support" and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates; and

- Fourteen additional projects at Jackson Plant totaling $1.098 million, with each individual project representing $225,000 or less in expenditures. These projects include (13476) JGS - LM1-6 Steam injection trap replacements, generator breaker replacements, breaker relay replacements, major motor and pump overhauls, and small valves, instrumentation, tools, equipment, pumps, and motors.

HYDRO UNITS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the Hydro Units.

A. The Company plans to invest $42.376 million in the 14-month bridge period and $92.258 million in the projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected $42.376 million capital investment in the 14-month projected bridge period?

A. The projected $42.376 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are ten projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 20 through 29. The basis for these projects is described in the direct testimony of Company witness Monroe.

Q. What is the basis for the projected $92.258 million capital investment in the projected test year?

A. The projected $92.258 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are 13 projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 21 through 33. The basis for these projects is described in the direct testimony of Company witness Monroe.

<u>LPS</u>

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for the LPS.

A. The Company plans to invest $10.279 million in the 14-month projected bridge period and $15.587 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively. These capital investments will be implemented in periodic outages in the spring of 2024 and 2025. It is important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected $10.279 million capital investment in the 14-month projected bridge period?

A. The projected $10.279 million capital investment in the 14-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 30-31. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement ($1,648,169). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS – Lower Penstock Expansion Joint ("LPEJ") Chamber Waterstop replacement ($2,716,000). The scope of this project is replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of $0.404 million and project implementation began in 2021 and is planned to be completed in 2024. In 2021, the engineering was completed, and the design was approved by FERC; and

- The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Replace Barrier Net Panels ($679,115). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Replace 480V Dike Load Centers ($993,800). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS Oil Water Separator Replacement ($780,249). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS Intake Gate and Gate House Mechanical Replacement ($409,099). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Governor Replacement ($474,167). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Ludington All Unit Critical Valve and Actuator Replacement ($565,000). The scope of this project is to replace valves, actuators, and associated equipment critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism; and

- Twenty-two additional projects at LPS totaling $2.014 million, with each individual project representing $256,896 or less in expenditures. These projects include LPS DAC 1 and 2 replacement, subdrainage and unwatering sump pump controls and pump replacement, CO2 Fire Protection System Replacement Centralized Grease System Replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $15.587 million capital investment in the projected test year?

A. The projected $15.587 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are five projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 34 through 38. The basis for these projects is described below:

- DCS Control Relay Replacement ($4,771,901). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic input/output modules and new relays where needed. The number of hardware control relays will be reduced due to the "control" being performed in logic instead of "hardwired" circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the Human Machine Interface ("HMI") graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end of life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Replace 480V DLCs ($1,566,400). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of $0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance;

- LPS Commons Station Power Transformer (“SPT”) Life Cycle Management ($1,150,000). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site, and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, extension of life expectancy to that of site, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare;

- Governor Replacement ($1,915,833). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear; and

- Intake Gate and Gate House Mechanical Replacement ($1,666,014). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- LPS Oil Water Separator ("OWS") Replacement ($438,746). The scope of work for this project is to install a separate, parallel train OWS to that of the plant's existing OWS, modify existing support systems (station sump, station sump pumps, and metering devices) to support new OWS, and retrofit the existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one as to not impact unit availability. The project is being performed in order to comply with requirements for effluent discharge during all modes of operation and process upset conditions. The failure to perform this project would likely lead to additional releases in excess of the National Pollutant Discharge Elimination System permit requirements throughout the facility's lifecycle. Although not quantified, cost for these releases could be significant in terms of potential fines, reputational damage, cleanup costs, and other intangibles;

- Centralized Grease System Replacement ($303,604). The scope of this project is to replace end of service life components such as pumps, distributing blocks, and solenoid valves, and to modernize the control system to a self-diagnostic

PLC system. The current electro-pneumatic grease system(s) that service certain bushings are past their service life and of questionable reliability (original plant functionally equipment);

- Replace Barrier Net Panels ($829,725). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and

- Nineteen additional projects at Ludington totaling $2.944 million, with each individual project representing $298,332 or less in capital expenditures. These projects include north fabrication shop storage mezzanine and humidity control, pony motor isolation switch life cycle project, all unit critical valve and actuator replacement, cathodic protection system replacement, main transformer bank isophase cooling blower replacement, subdrainage and unwatering sump pump controls and pump replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

<u>ADMINISTRATIVE AND OTHER</u>

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Administrative and Other.

A. The Company plans to invest $2.795 million in the 14-month projected bridge period and $3.096 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 78, columns (h) and (j), respectively.

Q. What is the basis for the projected $2.795 million capital investment in the 14-month projected bridge period for Administrative and Other?

A. The projected $2.795 million capital investment will support several projects during the 14-month bridge period. The basis for these projects is described below:

- Generation Operations – Ovation security center replacement evergreen ($300,000). The Generation control systems cyber security tool that is used for control system security is the Emerson PWCS. This tool is comprised of multiple cyber security products used in the industry today. Because of the quickly changing technology and techniques used by hackers, the cyber security tools require an increased update cycle of two to three years. The Karn site has been using the PWCS tool for 10 years. It was last upgraded in 2017. To support the latest version of Ovation DCS, the PWCS system must be upgraded. This replacement will support the protection of multiple components of the control system across multiple sites including Karn Units 3 and 4, Campbell, Jackson, Zeeland, and Ludington. The tools included are:

- Anti-Virus;
- Malware Prevention with Application Control;
- Patch Management;
- Device Control;
- Rogue System Detection;
- System Backup and Recovery;
- Security Incident and Event Manager; and
- Change Management.

- Fleet - Move the machine shop ($616,667). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and Other;

- Transformation - Enterprise Project Management Information System ($850,010). The scope of this project is the continuing support of Unifier, the Company's project management information system ("PMIS"). During the bridge period, the Company is implementing a major upgrade to Unifier and Primavera P6 ("P6"). Specifically, the Company is moving from version 19.12 to 22.12 for both Unifier and P6. The upgrade reflects three years of upgrades from oracle which includes various enhancements. The scope of the project also includes the February 2024 procurement of 350 additional licenses to support the continued user growth the Company expects from the new functionality in the upgrade. The increased user growth includes expansion of the products to additional engineering personnel, some project management personnel, and some vendors. In addition to the upgrade and procurement of additional licenses, the Company has continued its quarterly implementation of continuous-improvement updates (new functionality that Company users identify) that include the creation and or configuration of new reporting and business processes; and

- Seven additional projects totaling $1.028 for generation cyber security, ovation cyber security, laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management.

Q. What is the basis for the projected $3.096 million capital investment in the projected test year?

A. The projected $3.096 million capital investment in the projected test year will fund various projects. One of these projects is greater than $1 million, and is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 20. The basis for these projects is described below:

- Fleet - Move the machine shop ($2,100,000). The scope of this project is to move the machine shop. The existing machine shop is located at the Campbell site and with the closure of the Campbell units on May 31, 2025, the Company will likely have to relocate the existing machine shop. Options for the project include (1) doing nothing and going to third parties for parts which will impact both cost and timing of delivery, (2) purchasing another machine shop, (3) section off the training center at Campbell and move the machine shop to that building, and (4) Building a machine shop in a centralized location to better service all generation sites.

  The machine shop has proven its financial viability, with a positive variance of $67,978 in 2023. It has consistently demonstrated the ability to generate revenue exceeding operational costs, a trend expected to continue based on projections. The shop's ability to quickly turn around projects and fabricate parts faster than external vendors has led to substantial savings, particularly in replacement power costs, estimated at $300k annually; and

- Eight additional projects for generation cyber security, laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management ($996,250).

<u>**COMPANY-OWNED SOLAR RESOURCES**</u>

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for Company-owned solar resources.

A. The Company plans to invest $249.572 million in the 14-month projected bridge period and $275.959 million in the projected test year in Company-owned solar resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 50, columns (h) and (j), respectively.

Q. What is the basis for the projected $249.572 million capital investment in the 14-month projected bridge period?

A. The projected $249.572 million capital investment in the 14-month projected bridge period will fund the IRP-approved solar generation development. This entire investment amount is reflected in two separate projects, Muskegon Solar and Spring Creek, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 32 and 33. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected $275.959 million capital investment in the projected test year?

A. The projected $275.959 million capital investment in the projected test year will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Muskegon Solar, Washtenaw, and Spring Creek, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 39 through 41. The basis for those projects is described in the direct testimony of Company witness Clark.

BATTERY ENERGY STORAGE SYSTEMS

Q. Please explain the Company's projected capital expenditures for the 14-month projected bridge period ending February 28, 2025 and the projected test year ending February 28, 2026 for BESS.

A. The Company plans to invest $39.672 million in the 14-month projected bridge period and $78.921 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 85, columns (h) and (j), respectively.

Q. What is the basis for the projected $39.672 million capital investment in the 14-month projected bridge period?

A. The projected $39.672 million capital investment in the 14-month projected bridge period will fund BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 34 through 36. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected $78.921 million capital investment in the projected test year?

A. The projected $78.921 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in three separate projects, Armstrong, Iosco, and Weadock, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 42 through 44. The basis for those projects is described in the direct testimony of Company witness Clark.

Q. Are you supporting any other projected capital expenditures for generation related projects in the test year ending February 28, 2026?

A. Yes. I am also supporting an IT project, Generation Operations Digital Work Management. The test year projected capital expenditure amount is $713,873, and the test year projected O&M expense amount is $54,383. These amounts are reflected in the exhibits of Company witness Shivaji Kandan. The scope of the project includes: the initial roll out for Electric Generation at Ludington, and Renewable Generation, which would include: (1) purchase of mobile field devices for Ludington, (2) purchase of additional mobile work management software licenses, (3) development and configuration of forms and workflow for these groups, and (4) enhancement of the wireless connection at Ludington.

Q. What are the benefits of this technology project?

A. This project provides the following value to the Company: (1) Productivity is improved, and human struggle reduced by simplification of work tracking through the mobile software. Time sheet charging is incorporated to the work order when someone on the crew pushes the clock to start versus being separately entered through SAP Employee Self Service. If there is more than one person on a crew, information is entered for the full crew versus individually, including time tracking. Functionality is available to more easily create a digital punch list in the field when a worker sees something instead of later writing it on a punchboard and entering it separately into SAP; (2) Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile software to help them do their jobs; (3) Quality is improved by creating a digital punch list when the technicians find an issue versus manually documenting it later. Accuracy increases and rework decreases when updates are performed right at the time and place of the work instead of afterwards. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information; (4) Safety is improved as employees have remote access to manuals to reference before moving forward with and during their work. The access to manuals increases productivity and better supports error reduction training by having the manuals available so a worker can move beyond "I think" and "I believe." The project will mitigate the risk of work and safety errors from using outdated procedures; (5) For Renewable Generation, the improved maintenance program will reduce equipment downtime resulting in an increase to Megawatt hours produced; and (6) For Ludington, the new mobile devices will allow working with electronic Systems Operations Management System ("eSOMS") which will improve productivity and reduce non-premise time.

Q. Did the Company consider alternatives for this project?

A. Yes. The alternatives considered include: (1) Utilizing an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost; (2) Continuing the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error; (3) Customizing the existing electronic eSOMS mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support; and (4) Utilizing an out-of-the-box solution to minimize cost and risk to the Company and its employees. The combined Service Suite and digital form solution is the preferred option because it is a proven solution and provides the mobility and digital benefits at a lower cost than other alternatives.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark and Monroe provide additional discussion in their direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy

Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2023 through 12 Months Ending February 28, 2026 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2023 Generation O&M expense as \$118,848,652;
- Column (c) identifies the 14-Month Projected Bridge Period Generation O&M expense as \$165,164,491; and
- Column (d) identifies the Projected Test Year Generation O&M expense as \$111,850,689.

<u>HISTORICAL O&M EXPENSE</u>

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – "Base," "Environmental Operations," "Major Maintenance," and "Retention and Separation."

Q. What are Base O&M expenses?

A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company's generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles; (2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and grounds maintenance.

Q. Please explain how the 2023 Actual O&M expenses were developed.

A. The 2023 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 14-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the projected bridge period ending February 28, 2025, and projected test year ending February 28, 2026 shown on Exhibit A-43 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2023 through the projected test year demonstrates average annual decreases of approximately 2.7%. As discussed later in this direct testimony, this average annual decrease reflects a change in the mix of the Company's owned generating assets as well as focused cost reductions. Exhibit A-43 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Karn and Campbell sites. These expenses were required for the safe and reliable operation of Karn Units 1 and 2 through their May 2023 retirement and are required for the continued safe and reliable operation of Campbell Units 1, 2, and 3 through their May 2025 retirement.

Q. How do the historical and projected test year O&M expense amounts compare to prior years?

A. The 2023 historical O&M expense amount of $118.849 million and the projected test year O&M expense amount of $111.851 million compare quite favorably to the actual O&M expense amounts for 2021 and 2022. The 2021 generation O&M expense amount was $155.204 million, and the 2022 generation O&M expense amount was $150.031 million. As I previously stated, the O&M expense reductions reflect a mix of generation asset changes as well as other focused cost reductions.

Q. Please explain Exhibit A-43 (RTB-4), page 2.

A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or contract rate to historical O&M

expense. Column (b) presents the historical O&M expense. Column (c) presents the amount of the historical O&M amount to which an inflation rate or contract rate applies. Columns (e) and (g) present the amounts to which an inflation rate or contract rate were applied for each period, respectively. Columns (d), (f), and (h) present contract and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4), page 2.

A. The historical labor on line 1, column (b) reflects a combination of both Operating Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of 2.4%, 2.2%, and 2.2% were applied to labor on line 1, material on line 2, contractor on line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d), (f), and (h).

Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test period projected O&M expense amount of $111.851 million reflects that evaluation. Within the test period projected amount of $111.851 million, there are several adjustments that result in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustments that are reflected in the test year projected amount of $111.851 million.

A. As previously discussed, the Settlement Agreement reached in the Company's 2018 IRP reflects the retirement of Karn Units 1 and 2 on May 31, 2023 and the Settlement Agreement reached in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025 and the addition of Covert Units 1, 2 and 3 on June 1, 2023.

Q. Please discuss the decrease in O&M expense for Karn Units 1 and 2.

A. The 2023 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for the Karn site in 2023 was $19.091 million versus the projected O&M for the test year at $13.106 million, with the biggest decrease reflected in base O&M. The 2023 environmental operations expense for the Karn site was $2.254 million and that has been reduced to $0.093 million in the projected test year. The 2023 base O&M expense was $16.554 million whereas the projected test year base O&M drops to $10.411 million. The Karn major maintenance expense increases from $0.283 million in 2023 to $2.602 million in the projected test year. This increase reflects the fact that the Company limited the amount of major maintenance it planned for Karn Units 3 and 4 in 2023 since its 2021 IRP proposed the coincident retirement of those units with Karn Units 1 and 2. When the 2021 IRP settlement did not include Karn Units 3 and 4 retiring early, the Company needed to perform the deferred major maintenance. A complete discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2 and 3.

A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units will only operate for three months, March through May 2025. The projected test year expense for Campbell is $13.935 million, a $29.392 million reduction from the actual 2023 O&M expense of $43.327 million. The biggest reduction from the historical year to the projected test year is reflected in base O&M expense. The base O&M expense in the projected test year is $11.204 million, a $23.653 million reduction from the historical expense of $34.858 million. The 2023 environmental operations expense for Campbell was $6.421 million and that has been reduced to $2.186 million in the projected test year. The Campbell major maintenance expense decreases from $2.049 million in 2023 to only $0.545 million in the projected test year. A complete discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the increase in O&M expense for Covert Units 1, 2, and 3.

A. The 2023 O&M expense for Covert reflects the fact that the Company didn't take ownership of the plant until June 1, 2023. The actual O&M expense for Covert Units 1, 2 and 3 in 2023 was $7.413 million for the period from June 1, 2023 through December 31, 2023. The projected O&M for the test year is $16.873 million, with the biggest increase reflected in major maintenance. The 2023 expense for major maintenance was $2.144 million however it is project to total $7.706 million in the test year. A complete discussion of the test year major maintenance for Covert is described later in this direct testimony. The 2023 environmental operations expense for Covert was $0.072 million and that expense is slightly lower at $0.053 million in the projected test year. The base O&M

reflects an increase from $5.196 million for the period from June 1, 2023 through December 31, 2023, to $9.114 million in the test year.

Q. Are these generation asset changes the only reasons for the reduced O&M expense?

A. No. As I previously indicated, the Company has implemented other focused cost reductions that have directly impacted both the actual 2023 O&M expense and the projected test year expense. These cost reductions are primarily represented by headcount reductions during 2023 which have reduced both capital expenditures and O&M expense.

Q. Did the Company implement any projects that exclusively impacted capital expenditures?

A. Yes. The Company has implemented an improved governance process and key performance management metrics that will allow it to improve the efficiency of its capital expenditures. While the Company will not necessarily reduce its overall capital expenditures, it does expect that it will be able to accomplish more work with the same amount of capital.

Q. Did the Company implement any generation capital projects which reduce other customer costs?

A. Yes. The Company implemented a project at Jackson for the HRSG Burner Element Isolation Valves Addition (see Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 9) in 2023 that will reduce both O&M and PSCR expense. The project involved the addition of automated low point drain and vent on each gas manifold, the addition of isolation valves on all burner elements, and burner management system ("BMS") logic changes to control drains and vents. The benefits of the project are the mitigation of condensation in burner piping and elements which leads to ignition failure, burner tube failure, and flame impingement which would eventually lead to burner elements replacements because of those issues. In addition, the project will increase generation production or capability due to less duct burner down time because of the ability to isolate individual duct burners rather than an entire HRSG. The increased generation production or capability is intended to result in a reduction of PSCR costs, and the improved reliability of the burner elements will result in reduced O&M expense.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the operations of the Company's AQCS. As Federal and State emissions standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation. Now that the Company has experienced multiple calendar years of operation, the Company anticipates these expenses to remain relatively consistent going forward. However, because the cost to operate and maintain these critical pieces of equipment is directly related to the operation of the coal-fired power plants they support, yearly variances in the total Environmental Operations expense should be expected based on the operation of the coal plants in a given year.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending February 28, 2025 and test year ending February 28, 2026 were calculated.

A. Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. The operations component is primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. 2023 was the seventh full year of operations of the environmental equipment at both Campbell and Karn, and the Company now has robust historical data to use in projecting these expenses. However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2023 historical expense of $9.225 million to the projected test year expense of $2.584 million reflects a cost reduction of $6.641 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31, 2023 and the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the Major Maintenance O&M expenses for the projected bridge period ending February 28, 2025 and test year ending February 28, 2026 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

Q. Please identify the 2023 test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $31.203 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4, column (d). Test year Major Maintenance expense by generating unit is presented on Exhibit A-43 (RTB-4), page 3, column (d).

Q. Why is Consumers Energy spending $31.203 million in Total Major Maintenance O&M expense during the projected test year ending February 28, 2026?

A. The Company is spending the majority of its Total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed and minimizing damage that could result in the event of a catastrophic failure.

Q. Are Major Maintenance expenses relatively consistent from year to year?

A. No. Although the Company attempts to plan for controlled and consistent levels of Major Maintenance, because Major Maintenance outages occur relatively infrequently, for an individual unit, it is very possible to have significant year-by-year variations in the number, duration, and magnitude of the required Major Maintenance work. Other factors such as unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

Q. Is it possible that changes to the Company's forecasted Major Maintenance plan could occur?

A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. The Company attempts to make the best decision in balancing the cost and risks associated with the operation of the equipment and attempts to minimize the cost to customers. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability considerations can affect the actual timing of an outage and maintenance spending.

Q. Do Major Maintenance costs vary by individual generating unit(s)?

A. Yes. As the Company's generating units vary in age, size, type, and design, so do the costs to maintain these units. As an example, Major Maintenance of Campbell Unit 3 coal pulverizers (785 MW) would be considerably larger in scope and cost than Major Maintenance of Campbell Unit 1 coal pulverizers (260 MW), which is located on the same site.

Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch of generating units in its generation portfolio?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. What are the categories of Major Maintenance?

A. Major Maintenance is broken into two categories—outage and non-outage.

Q. Please describe what is included in the outage major maintenance O&M expense.

A. Outage major maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for boiler and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are needed to control the unit output. During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

Q. Please describe the work completed in a boiler inspection.

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

Q. Please describe the work completed in a turbine inspection.

A. Turbine inspections consist of disassembling, inspecting, and cleaning the different components of the turbine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Because of the extreme conditions under which these units operate, the demand for uninterrupted power, and dangers associated with operating these large pieces of equipment, industry standards recommend that inspections be completed every seven years.

Q. Please define non-outage maintenance.

A. Non-outage maintenance O&M costs typically do not require the generating unit be removed from service, but they are still critical to the operation of the unit. An example of non-outage maintenance is Mill/Pulverizer maintenance.

<u>Campbell Units 1 and 2 Major Maintenance</u>

Q. Please describe Campbell Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 1, column (d), Campbell Units 1 and 2 Major Maintenance expense is forecasted to be $0.268 million in the projected test year ending February 28, 2026, and includes:

- Campbell Units 1 and 2 Periodic Outage Major Maintenance ($60,000). The scope of this project is to perform boiler maintenance activities during outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;

- Campbell Unit 1 Pulverizer Maintenance ($60,000). The scope of this project is the procurement of required parts to support the on-going maintenance of the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 2 Mill Maintenance — Parts Only Boiler Plant Equipment ($60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal mill/pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation; and

- One project common to Campbell Units 1 and 2 totaling $30,010 and two Site Common Major Maintenance projects totaling $135,577 which are shared with Campbell Unit 3. Campbell Units 1 and 2 receive a 43% allocation totaling $58,298 and Campbell Unit 3 receives a 57% allocation or $77,279. These projects, all of which represent $92,377 or less in expense, include fuel handling dumper outage repairs, deepwater intake screen inspection, and SDA O&M costs.

<u>**Campbell Unit 3 Major Maintenance**</u>

Q. Please describe Campbell Unit 3 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 2, column (d), Campbell Unit 3 Major Maintenance expense is forecasted to be $0.277 million in the test year and includes:

- Campbell Unit 3 Pulverizer Maintenance — Parts Only Mills-Boiler Plant Equipment ($60,000). The scope of this project is the procurement of required parts to support the on-going maintenance on the coal pulverizers to maintain their operability. This maintenance work will allow the Company to keep the minimum number of mills in service and, as a result, avoid unit derates due to degraded conditions. The performance of this work will result in safe, reliable, and efficient unit operation;

- Campbell Unit 3 Periodic Outage Major Maintenance ($94,384). The scope of this project is to perform boiler, turbine, and BOP maintenance activities during outages during the project test year. Expenses include planning, engineering services, materials, and overtime labor. Performance of this work will result in improved unit reliability and performance; and

- One other Campbell Unit 3 project totaling $45,000 and two Site Commons projects that I discussed previously with the Campbell Unit 3 allocation totaling $77,279.

Karn Units 1 and 2 Major Maintenance

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be $0.100 million in the projected test year ending February 28, 2026. This forecasted expense for the projected test year ending February 28, 2026 is for vegetation removal.

Covert Plant Major Maintenance

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be $7.706 million in the projected test year ending February 28, 2026, and includes:

- Covert Plant LTSA Major Maintenance ($2,611,312). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant LTSA extra work Major Maintenance ($1,492,500). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;

- Covert Plant Capacity Factor Used For Water and Chemicals ($1,216,667). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Reverse Osmosis System (“RO”), operation agreement ($461,667). The scope of this project is to contract with a third party to operate and maintain the RO system;

- Covert Plant Base Outage Funding – Boiler plant equipment ($483,333). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- Covert Plant HEPS/FAC/DAST Inspections ($913,333). This project will include the performance of regulatory required high energy piping surveillance (“HEPS”), deaerator and its storage tank (“DAST”) mid cycle inspection, and flow accelerated corrosion (“FAC”) inspection; and

- Four additional projects for Covert totaling $527,500 in expenses, with each individual project representing $275,000 or less in expenses. These projects include NERC relay and DC testing, ITC switchyard upgrades, gas turbine exhaust expansion joints repairs, and 345 kV transformer bushing power factor testing.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be $2.502 million in the projected test year ending February 28, 2026, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance ($355,833). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Karn Units 3 and 4 HEPS/FAC/DAST Inspections ($375,000 per unit). This project will include the performance of regulatory required inspections;
- Karn Unit 3 Turbine Valve Inspections ($241,667). The scope of this project is to perform the Karn Unit 3 turbine valve inspections;
- Karn Unit 4 Main Transformer Bladder Replacement ($208,333). The scope of this project is to replace the bladder. The main transformer conservator bladder is broken and open to atmosphere, making the oil susceptible to air bubbles and increasing the risk of transformer failure; and
- Fourteen additional projects for Karn Units 3 and 4 totaling $946,333 in expenses, with each individual project representing $150,000 or less in expenses. These projects include critical motor major maintenance, forced draft and induced draft fan alignments, station power relay maintenance, and opacity critical equipment repairs.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be $5.232 million in the projected test year ending February 28, 2026, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract ($2,048,614). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals ($1,255,417). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Base Outage — Boiler Plant Equipment ($558,333). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;

- Zeeland Site Commons Deep Well Injection Cleaning ($323,333). The scope of this project is the third-party cleaning of the well. Cleaning the well allows Zeeland to continue to operate in the most economical means practical and maintain the required plant equipment. Failure to clean the well would require the plant to blowdown all cooling tower concentrate to the city sewer at a considerable expense. This activity is performed on a triennial basis; and

- Fourteen additional projects totaling $1,045,984 in expenses, with each individual project representing $208,333 or less in expenses. These include excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, large oil-filled transformer maintenance, breaker maintenance, and NERC-required relay testing.

<u>Jackson Plant Major Maintenance</u>

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be $3.852 million in the projected test year ending February 28, 2026. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals ($1,900,000). This item provides for the city water used by the Jackson Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Non-LTSA Turbine and jet engine repairs ($391,667). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;

- Jackson Plant LTSA — Running Maintenance Contract ($508,333). Consumers Energy has a long-term maintenance agreement with GE to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Jackson Plant Base Outage - Boiler plant equipment ($250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and

- Ten additional projects totaling $801,565 with each individual project representing $241,853 or less in expenses. These include HEPS, FAC, pre-Filter replacement, high voltage maintenance and NERC testing, and filter house roof maintenance.

<u>**LPS Major Maintenance**</u>

Q. Please describe LPS Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be $4.445 million in the projected test year ending February 28, 2026, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal ($2,140,000). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;

- Nine Year Unit Mechanical Interval Inspection and Replacement ($570,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six units as well as up front planning and procurement funding in the first year;

- Reservoir remediation ($535,833). This is FERC required and related to dam safety to ensure the Company maintains the integrity of the Ludington pond; and

- Twenty-two additional projects totaling $1,199,508, with each individual project representing less than $161,000 in expenses. These include asphalt liner inspection repairs, penstock condition assessment and monitoring study, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, lube oil room repair, Polychlorinated Biphenyl removal and disposal, and powerhouse slope terrace drain cleanout.

Hydro Major Maintenance

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be $5.776 million in the projected test year ending February 28, 2026, and includes:

- Hydro License Initiatives ($2,158,667). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;

- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections ($1,446,475). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years (FERC Part 12 regulations are discussed in Mr. Monroe’s direct testimony). A similar level of expense is budgeted annually from 2025 through 2028;

- Hardy Intake Tower Brick Repair ($241,667). The scope of this project is to replace all the deteriorated interior brick inside the intake tower for the full height. The Hardy intake tower brickwork has been slowly deteriorating for the last few years. The bricks are crumbling to the touch and has areas with significant delamination throughout the entire height of the walls (34ft). If the deterioration becomes significant enough, it may impact the headgate hoists and the head gates installation safety of the Operations staff;

- Tippy Spillway Chamber Inspections and Repairs ($202,500). The project scope includes performing spillway chamber inspections, engineering for spillway chamber repairs and construction of repairs. The Tippy spillway chambers are hollow chambers underneath the spillway. In the spillway chambers, the concrete is deteriorated, rebar is exposed, and there is seepage present;

- Hydro Concrete Repairs ($206,958). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process; and

- Twenty-six additional projects totaling $1,520,083 with each individual project representing $150,000 or less in expenses. These projects include Cooke Powerhouse Divider Pier, Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project, Tippy Log Chute Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

<u>Solar Major Maintenance</u>

Q. Please describe Solar Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 11, column (d), Solar Major Maintenance expense is forecasted to be $0.677 million in the projected test year ending February 28, 2026 and includes three projects, all to provide IT support for the Mustang Mile, Muskegon Solar, and Washtenaw Solar IRP solicitation projects. For each of the solar sites, the major maintenance funding includes plant setup in SAP, and payment of the OSISoft PI Historian and Bazefield SCADA overlay license fees.

<u>Admin and Other Major Maintenance</u>

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be $0.150 million in the projected test year ending

February 28, 2026 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (B.C. Cobb ("Cobb"), J.C. Weadock ("Weadock"), and J.R. Whiting ("Whiting") units) Major Maintenance expenses for the projected test year ending February 28, 2026.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be $0.218 million in the projected test year ending February 28, 2026.

Q. Why is Consumers Energy projecting to spend $0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending February 28, 2026?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of $17.348 million in 2023, and is projecting expense of $11.158 million in the 14-month projected bridge period, and $4.621 million in the projected test year. The actual 2023 expense of $17.348 million is based upon expense of $1.501 million for Karn and

$15.847 million for Campbell. The 14-month projected bridge period expense of $11.158 million is entirely based upon expense of $11.158 million for Campbell. The projected test year expense of $4.621 million is based upon expense of $4.621 million for Campbell.

Q. Is the Company requesting O&M recovery of the $4.621 million projected amount for the projected test year?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in electric rate case, Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2023 through the projected test year ending February 28, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Aponte supports regulatory asset treatment of these expenses in her direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan is a people strategy that the Company has implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold and dark time period following retirement. The cold and dark condition refers to the period following plant retirement and prior to plant decommissioning. During this period, limited environmental remediation and perhaps partial demolition is performed. The facility may be physically secured with fencing and other measures to prevent vandalism or theft so as to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

Q. What is the purpose of the retention component of the Company's plan?

A. The Company had a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 became increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company had the ability to hire new employees, the training time necessary for any new hires provided a significant challenge to operating the units both safely and reliably. The retention component utilized the best practices that the Company employed in retiring the Classic 7.

Q. What is the purpose of the separation component of the Company's plan?

A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers varies based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Karn retention and separation plan?

A. The Karn retention and separation plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Karn retention and separation plan.

A. The retention benefits associated with the Karn retention and separation plan include three payment components: a signing incentive, annual incentives, and a final retention incentive.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in October 2019. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Karn until October 31, 2020 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2020, the employee forfeited the signing incentive.

Employees receive an annual incentive which graduated from 20% to 30% of their base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and rendering service for the next 12 months. The employee had to stay at Karn until October 31 of the following year to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31 of the next year, the employee forfeited the annual incentive. Eligible employees received their first annual incentive payment in November 2020, a second payment in November 2021, and a third payment in November 2022.

Employees received their final retention incentive equal to 60% of their base pay following plant retirement if the employee was still at Karn. The payment was intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

Q. Please describe the severance benefits associated with the Karn retention and separation plan.

A. The severance benefits associated with the Karn retention and separation plan includes initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Karn Units 1 and 2?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (11 within 60 miles of the Karn site) to which employees can relocate, than it did in 2016. As such, the Company anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees.

Q. Please explain the relevant details of the collective bargaining agreement for OM&C employees.

A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and the Generation Operations Coal Closing Agreement provide that employees will be placed in either a corresponding position, or if none exists, in a vacant position he/she is qualified to perform within 60 miles of his/her current headquarters. Per Article XVII of the collective bargaining agreement, employees who are released due to lack of work, and are not placed as described above, are provided a separation allowance consisting of straight time pay for five regular workdays for each year of continuous service with the Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2, as described above, it was anticipated that some employees would be eligible for a separation allowance.

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date. This incentive program is the same program that is currently in place for employees at the Karn site.

Q. What is the purpose of the retention component of the Company's plan?

A. For similar reasons described in the Karn retention plan, the Company has a strong interest in keeping qualified employees working at the Campbell site through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. Similar to the situation at the Karn site, it will be increasingly difficult to hire new employees at the Campbell site given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the three units both safely and reliably.

Q. What is the purpose of the separation component of the Company's plan?

A. When the Campbell units are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Campbell retention plan?

A. Similar to the Karn retention and separation plan, the Campbell retention plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Campbell retention plan.

A. The retention benefits associated with the Campbell retention plan include three payment components: a signing incentive, periodic incentives, and a final retention incentive. The timeline for retention benefits reflects approval of the Settlement Agreement in the Company's 2021 IRP in June 2022.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in July 2022. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Campbell until October 31, 2022 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2022, the employee forfeited the signing incentive.

Employees receive a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell and rendering service for a certain period. Specifically, for service provided July 2022 through October 2022, employees received 20% of their base pay. For service provided November 2022 through October 2023, employees received 25% of base pay. For service provided November 2023 through October 2024, employees will receive 30% of base pay. The employee must stay at Campbell until October 31 of the given year to receive the payment; if the employee stays until that date, the incentive was/will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the given year, the employee forfeits the annual incentive.

Employees receive a final retention incentive equal to 60% of their base pay on or about October 31, 2025, if the employee is still at Campbell. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the 12 months prior to the payment.

Q. Please describe the severance benefits associated with the Campbell retention plan.

A. The severance benefits associated with the Campbell retention plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Campbell Units 1, 2, and 3?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (seven within 60 miles of the Campbell site) to which employees can relocate, than it did in 2016. In addition, the Company will also have retired at least two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees, as previously discussed for the Karn retention and separation plan.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures
($000)

Line No.	(a) Description	(b) Historical Year 12 Months Ended 12/31/2023	(c) Projected Bridge Period 12 Mos Ended 12/31/2024	(d) Projected Bridge Period 2 Mos Ending 2/28/2025	(e) Projected Bridge Period 14 Mos Ending 2/28/2025	(f) Projected Test Year 12 Mos Ending 2/28/2026
1	Steam Power Generation					
2	Environmental	$ (1,274)	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 11,813	$ 16,565	$ 554	$ 17,119	$ 7,287
4	Total Steam Production	$ 10,539	$ 16,565	$ 554	$ 17,119	$ 7,287
5	Hydraulic Power Generation					
6	Routine and Small CapEx	$ 25,530	$ 38,052	$ 4,324	$ 42,376	$ 92,258
7	Total hydraulic production	$ 25,530	$ 38,052	$ 4,324	$ 42,376	$ 92,258
8	Pumped Storage Generation					
9	Ludington Overhaul	$ 1,252	$ -	$ -	$ -	$ -
10	Routine and Small CapEx	$ 9,389	$ 8,717	$ 1,563	$ 10,279	$ 15,587
11	Total Pumped Storage Generation	$ 10,642	$ 8,717	$ 1,563	$ 10,279	$ 15,587
12	Other Production Plant					
13	Routine and Small CapEx	$ 812,384	$ 275,971	$ 117,803	$ 393,774	$ 485,354
14	Total Other Production Plant	$ 812,384	$ 275,971	$ 117,803	$ 393,774	$ 485,354
15	SubTotal	$ 859,095	$ 339,304	$ 124,244	$ 463,548	$ 600,484
16	Less Contingency	$ -	$ -	$ -	$ -	$ -
17	Grand Total	$ 859,095	$ 339,304	$ 124,244	$ 463,548	$ 600,484

Line No.	(a)	(b) Projected 2 Mos Ending 2/29/2024	(c) Projected 12 Mos Ending 2/28/2025	(d) Projected 12 Mos Ending 2/28/2026	(e) Projected 26 Mos Ending 2/28/2026
1	Steam Power Generation				
2	Environmental	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 3,773	$ 13,346	$ 7,287	$ 24,405
4	Total Steam Production	$ 3,773	$ 13,346	$ 7,287	$ 24,405
5	Hydraulic Power Generation				
6	Routine and Small CapEx	$ 2,404	$ 39,972	$ 92,258	$ 134,633
7	Total hydraulic production	$ 2,404	$ 39,972	$ 92,258	$ 134,633
8	Pumped Storage Generation				
9	Ludington Overhaul				$ -
10	Routine and Small CapEx	$ 780	$ 9,499	$ 15,587	$ 25,866
11	Total Pumped Storage Generation	$ 780	$ 9,499	$ 15,587	$ 25,866
12	Other Production Plant				
13	Routine and Small CapEx	$ 27,570	$ 366,204	$ 485,354	$ 879,128
14	Total Other Production Plant	$ 27,570	$ 366,204	$ 485,354	$ 879,128
15	SubTotal	$ 34,526	$ 429,022	$ 600,484	$ 1,064,032
16	Less Contingency	$ -	$ -	$ -	$ -
17	Grand Total	$ 34,526	$ 429,022	$ 600,484	$ 1,064,032

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
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($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		Projected Bridge Period						Projected Test Year	
Line No.	Description	12 Months Ended 12/31/2023		12 Months Ending 12/31/2024		2 Months Ending 2/28/2025		14 Months Ending 2/28/2025		12 Months Ending 2/28/2026	
1	**JHCampbell 1&2**	**$ (1,497)**		**$ -**		**$ -**		**$ -**		**$ -**	
2	Contractor		$ (1,373)		$ -		$ -		$ -		$ -
3	Labor		$ (165)		$ -		$ -		$ -		$ -
4	Materials		$ 531		$ -		$ -		$ -		$ -
5	Business Expenses		$ (29)		$ -		$ -		$ -		$ -
6	Contingency		$ -		$ -		$ -		$ -		$ -
7	Other (Loadings, Chargebacks)		$ (461)		$ -		$ -		$ -		$ -
8	**JHCampbell 3**	**$ 456**		**$ -**		**$ -**		**$ -**		**$ -**	
9	Contractor		$ (618)		$ -		$ -		$ -		$ -
10	Labor		$ (207)		$ -		$ -		$ -		$ -
11	Materials		$ 1,341		$ -		$ -		$ -		$ -
12	Business Expenses		$ (357)		$ -		$ -		$ -		$ -
13	Contingency		$ -		$ -		$ -		$ -		$ -
14	Other (Loadings, Chargebacks)		$ 296		$ -		$ -		$ -		$ -
15	**DEKarn 1&2**	**$ (81)**		**$ -**		**$ -**		**$ -**		**$ -**	
16	Contractor		$ (62)		$ -		$ -		$ -		$ -
17	Labor		$ (13)		$ -		$ -		$ -		$ -
18	Materials		$ 14		$ -		$ -		$ -		$ -
19	Business Expenses		$ -		$ -		$ -		$ -		$ -
20	Contingency		$ -		$ -		$ -		$ -		$ -
21	Other (Loadings, Chargebacks)		$ (20)		$ -		$ -		$ -		$ -
22	**DEKarn 3&4**	**$ 12,935**		**$ 16,565**		**$ 554**		**$ 17,119**		**$ 7,287**	
23	Contractor		$ 6,825		$ 14,062		$ 470		$ 14,532		$ 6,186
24	Labor		$ 234		$ 50		$ 2		$ 51		$ 22
25	Materials		$ 2,555		$ -		$ -		$ -		$ -
26	Business Expenses		$ (1)		$ -		$ -		$ -		$ -
27	Contingency		$ -		$ -		$ -		$ -		$ -
28	Other (Loadings, Chargebacks)		$ 3,322		$ 2,453		$ 82		$ 2,535		$ 1,079
29	**Zeeland**	**$ 41,443**		**$ 36,364**		**$ 12,153**		**$ 48,518**		**$ 50,929**	
30	Contractor		$ 27,583		$ 29,451		$ 9,843		$ 39,294		$ 41,248
31	Labor		$ 505		$ 95		$ 32		$ 126		$ 132
32	Materials		$ 5,583		$ 389		$ 130		$ 519		$ 545
33	Business Expenses		$ 37		$ -		$ -		$ -		$ -
34	Contingency		$ -		$ -		$ -		$ -		$ -
35	Other (Loadings, Chargebacks)		$ 7,735		$ 6,429		$ 2,149		$ 8,578		$ 9,004
36	**Jackson Generating Station**	**$ 20,979**		**$ 16,727**		**$ 2,403**		**$ 19,130**		**$ 14,965**	
37	Contractor		$ 15,651		$ 13,719		$ 1,971		$ 15,690		$ 12,274
38	Labor		$ 430		$ 30		$ 4		$ 34		$ 27
39	Materials		$ 1,994		$ 256		$ 37		$ 293		$ 229
40	Business Expenses		$ 24		$ -		$ -		$ -		$ -
41	Contingency		$ -		$ -		$ -		$ -		$ -
42	Other (Loadings, Chargebacks)		$ 2,880		$ 2,721		$ 391		$ 3,112		$ 2,435
43	**Covert**	**$ 680,305**		**$ 28,441**		**$ 5,646**		**$ 34,087**		**$ 61,483**	
44	Contractor		$ 11,579		$ 23,709		$ 4,707		$ 28,415		$ 51,252
45	Labor		$ 165		$ -		$ -		$ -		$ -
46	Materials		$ 972		$ 131		$ 26		$ 157		$ 283
47	Business Expenses		$ 664,876		$ -		$ -		$ -		$ -
48	Contingency		$ -		$ -		$ -		$ -		$ -
49	Other (Loadings, Chargebacks)		$ 2,713		$ 4,602		$ 914		$ 5,515		$ 9,948
50	**Solar**	**$ 69,040**		**$ 152,455**		**$ 97,117**		**$ 249,572**		**$ 275,959**	
51	Contractor		$ 64,558		$ 147,043		$ 93,669		$ 240,712		$ 266,162
52	Labor		$ 193		$ 534		$ 340		$ 874		$ 966
53	Materials		$ -		$ -		$ -		$ -		$ -
54	Business Expenses		$ 3,269		$ 915		$ 583		$ 1,497		$ 1,656
55	Contingency		$ -		$ -		$ -		$ -		$ -
56	Other (Loadings, Chargebacks)		$ 1,020		$ 3,964		$ 2,525		$ 6,489		$ 7,175

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		**Projected Bridge Period**						**Projected Test Year**	
Line No.	**Description**	**12 Months Ended 12/31/2023**		**12 Months Ending 12/31/2024**		**2 Months Ending 2/28/2025**		**14 Months Ending 2/28/2025**		**12 Mos Ending 2/28/2026**	
57	**Classic 7**	**-**		**-**		**-**					
58	Contractor		-		-		-		-		-
59	Labor		-		-		-		-		-
60	Materials		-		-		-		-		-
61	Business Expenses		-		-		-		-		-
62	Contingency		-		-		-		-		-
63	Other (Loadings, Chargebacks)		-		-		-		-		-
64	**Hydros**	**25,530**		**38,052**		**4,324**		**42,376**		**92,258**	
65	Contractor		16,949		28,653		3,256		31,909		69,470
66	Labor		1,116		282		32		314		683
67	Materials		867		-		-		-		-
68	Business Expenses		564		-		-		-		-
69	Contingency		-		-		-		-		-
70	Other (Loadings, Chargebacks)		6,034		9,117		1,036		10,153		22,105
71	**Ludington**	**10,642**		**8,717**		**1,563**		**10,279**		**15,587**	
72	Contractor		3,840		13,811		2,476		16,286		24,695
73	Labor		195		148		27		175		265
74	Materials		1,543		-		-		-		-
75	Business Expenses		(13)		-		-		-		-
76	Contingency		-		-		-		-		-
77	Other (Loadings, Chargebacks)		5,076		(5,242)		(940)		(6,182)		(9,374)
78	**Admin and Other**	**544**		**2,311**		**484**		**2,795**		**3,096**	
79	Contractor		69		1,386		290		1,676		1,857
80	Labor		23		-		-		-		-
81	Materials		351		-		-		-		-
82	Business Expenses		1		841		176		1,017		1,127
83	Contingency		-				-		-		-
84	Other (Loadings, Chargebacks)		100		84		18		101		112
85	**Battery Storage**	**74**		**39,672**		**-**		**39,672**		**78,921**	
86	Contractor		31		37,320		-		37,320		74,510
87	Labor		14		1,225		-		1,225		2,325
88	Materials		-				-		-		-
89	Business Expenses		-				-		-		-
90	Contingency		-				-		-		-
91	Other (Loadings, Chargebacks)		29		1,127		-		1,127		2,086
92	**All Other Environmental**	**(1,274)**		**-**		**-**		**-**		**-**	
93	Contractor		(993)		-		-		-		-
94	Labor		(61)		-		-		-		-
95	Materials		26		-		-		-		-
96	Business Expenses		46		-		-		-		-
97	Contingency		-		-		-				-
98	Other (Loadings, Chargebacks)		(292)		-		-		-		-
99	**Total Capital**	859,095	859,095	339,304	339,304	124,244	124,244	463,548	463,548	600,484	600,484

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MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
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Generation Capital Expenditures

Line No.	Description (a)	Projected 2 Mos Ending 2/28/2024 (b)	Projected 12 Mos Ending 2/28/2025 (c)	Projected 12 Mos Ending 2/28/2026 (d)	Projected 26 Mos Ending 2/28/2026 (e)
1	**JHCampbell 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
2	Contractor	$ -	$ -	$ -	$ -
3	Labor	$ -	$ -	$ -	$ -
4	Materials	$ -	$ -	$ -	$ -
5	Business Expenses	$ -	$ -	$ -	$ -
6	Contingency	$ -	$ -	$ -	$ -
7	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
8	**JHCampbell 3**	**$ -**	**$ -**	**$ -**	**$ -**
9	Contractor	$ -	$ -	$ -	$ -
10	Labor	$ -	$ -	$ -	$ -
11	Materials	$ -	$ -	$ -	$ -
12	Business Expenses	$ -	$ -	$ -	$ -
13	Contingency	$ -	$ -	$ -	$ -
14	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
15	**DEKarn 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
16	Contractor	$ -	$ -	$ -	$ -
17	Labor	$ -	$ -	$ -	$ -
18	Materials	$ -	$ -	$ -	$ -
19	Business Expenses	$ -	$ -	$ -	$ -
20	Contingency	$ -	$ -	$ -	$ -
21	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
22	**DEKarn 3&4**	**$ 3,773**	**$ 13,346**	**$ 7,287**	**$ 24,405**
23	Contractor	$ 3,203	$ 11,329	$ 6,186	$ 20,718
24	Labor	$ 11	$ 40	$ 22	$ 73
25	Materials	$ -	$ -	$ -	$ -
26	Business Expenses	$ -	$ -	$ -	$ -
27	Contingency	$ -	$ -	$ -	$ -
28	Other (Loadings, Chargebacks)	$ 559	$ 1,977	$ 1,079	$ 3,614
29	**Zeeland**	**$ 15,536**	**$ 32,982**	**$ 50,929**	**$ 99,447**
30	Contractor	$ 12,582	$ 26,712	$ 41,248	$ 80,542
31	Labor	$ 40	$ 86	$ 132	$ 259
32	Materials	$ 166	$ 353	$ 545	$ 1,064
33	Business Expenses	$ -	$ -	$ -	$ -
34	Contingency	$ -	$ -	$ -	$ -
35	Other (Loadings, Chargebacks)	$ 2,747	$ 5,831	$ 9,004	$ 17,582
36	**Jackson Generating Station**	**$ 1,890**	**$ 17,240**	**$ 14,965**	**$ 34,095**
37	Contractor	$ 1,550	$ 14,140	$ 12,274	$ 27,965
38	Labor	$ 3	$ 31	$ 27	$ 61
39	Materials	$ 29	$ 264	$ 229	$ 522
40	Business Expenses	$ -	$ -	$ -	$ -
41	Contingency	$ -	$ -	$ -	$ -
42	Other (Loadings, Chargebacks)	$ 307	$ 2,805	$ 2,435	$ 5,547
43	**Covert**	**$ 4,175**	**$ 29,912**	**$ 61,483**	**$ 95,570**
44	Contractor	$ 3,480	$ 24,935	$ 51,252	$ 79,668
45	Labor	$ -	$ -	$ -	$ -
46	Materials	$ 19	$ 138	$ 283	$ 440
47	Business Expenses	$ -	$ -	$ -	$ -
48	Contingency	$ -	$ -	$ -	$ -
49	Other (Loadings, Chargebacks)	$ 676	$ 4,840	$ 9,948	$ 15,463
50	**Solar**	**$ 5,144**	**$ 244,428**	**$ 275,959**	**$ 525,531**
51	Contractor	$ 4,961	$ 235,751	$ 266,162	$ 506,875
52	Labor	$ 18	$ 855	$ 966	$ 1,839
53	Materials	$ -	$ -	$ -	$ -
54	Business Expenses	$ 31	$ 1,467	$ 1,656	$ 3,153
55	Contingency	$ -	$ -	$ -	$ -
56	Other (Loadings, Chargebacks)	$ 134	$ 6,355	$ 7,175	$ 13,664

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Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	2 Mos Ending 2/29/2024	12 Mos Ending 2/28/2025	12 Mos Ending 2/28/2026	26 Mos Ending 2/28/2026
57	**Classic 7**	**$ -**	**$ -**	**$ -**	**$ -**
58	Contractor	$ -	$ -	$ -	$ -
59	Labor	$ -	$ -	$ -	$ -
60	Materials	$ -	$ -	$ -	$ -
61	Business Expenses	$ -	$ -	$ -	$ -
62	Contingency	$ -	$ -	$ -	$ -
63	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
64	**Hydros**	**$ 2,404**	**$ 39,972**	**$ 92,258**	**$ 134,633**
65	Contractor	$ 1,810	$ 30,099	$ 69,470	$ 101,379
66	Labor	$ 18	$ 296	$ 683	$ 996
67	Materials	$ -	$ -	$ -	$ -
68	Business Expenses	$ -	$ -	$ -	$ -
69	Contingency	$ -	$ -	$ -	$ -
70	Other (Loadings, Chargebacks)	$ 576	$ 9,577	$ 22,105	$ 32,258
71	**Ludington**	**$ 780**	**$ 9,499**	**$ 15,587**	**$ 25,866**
72	Contractor	$ 1,235	$ 15,051	$ 24,695	$ 40,982
73	Labor	$ 13	$ 161	$ 265	$ 440
74	Materials	$ -	$ -	$ -	$ -
75	Business Expenses	$ -	$ -	$ -	$ -
76	Contingency	$ -	$ -	$ -	$ -
77	Other (Loadings, Chargebacks)	$ (469)	$ (5,713)	$ (9,374)	$ (15,556)
78	**Admin and Other**	**$ 170**	**$ 2,625**	**$ 3,096**	**$ 5,891**
79	Contractor	$ 102	$ 1,574	$ 1,857	$ 3,533
80	Labor	$ -	$ -	$ -	$ -
81	Materials	$ -	$ -	$ -	$ -
82	Business Expenses	$ 62	$ 955	$ 1,127	$ 2,144
83	Contingency	$ -	$ -	$ -	$ -
84	Other (Loadings, Chargebacks)	$ 6	$ 95	$ 112	$ 214
85	**Battery Storage**	**$ 655**	**$ 39,017**	**$ 78,921**	**$ 118,594**
86	Contractor	$ 655	$ 36,665	$ 74,510	$ 111,831
87	Labor	$ -	$ 1,225	$ 2,325	$ 3,550
88	Materials	$ -	$ -	$ -	$ -
89	Business Expenses	$ -	$ -	$ -	$ -
90	Contingency	$ -	$ -	$ -	$ -
91	Other (Loadings, Chargebacks)	$ -	$ 1,127	$ 2,086	$ 3,213
92	**All Other Environmental**	**$ -**	**$ -**	**$ -**	**$ -**
93	Contractor	$ -	$ -	$ -	$ -
94	Labor		$ -	$ -	$ -
95	Materials		$ -	$ -	$ -
96	Business Expenses		$ -	$ -	$ -
97	Contingency		$ -	$ -	$ -
98	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
99	**SubTotal**	$ 34,526	$ 429,022	$ 600,484	$ 1,064,032
100	**Less Contingency**	$ -	$ -	$ -	$ -
101	**Grand Total**	$ 34,526	$ 429,022	$ 600,484	$ 1,064,032

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Case No.: U-21585
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
Page: 6 of 9
Witness: RTBlumenstock
Date: May 2024

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No.	Description	12 Months Ended 12/31/2023	12 Months Ending 12/31/2024	2 Months Ending 2/28/2025	14 Months Ending 2/28/2025	12 Months Ending 2/28/2026
1	Contractor	$ 144,039	$ 309,154	$ 116,682	$ 425,836	$ 547,655
2	Labor	$ 2,430	$ 2,363	$ 436	$ 2,799	$ 4,420
3	Materials	$ 15,776	$ 776	$ 193	$ 969	$ 1,057
4	Business Expenses	$ 668,417	$ 1,756	$ 759	$ 2,515	$ 2,783
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 28,433	$ 25,255	$ 6,174	$ 31,430	$ 44,571
	Total	$ 859,095	$ 339,304	$ 124,244	$ 463,548	$ 600,484

	(a)	(b)	(c)	(d)	(e)	(f)
		Projected				
Line No.	Description	12 Months Ending 12/31/2024	2 Months Ending 2/28/2025	14 Months Ending 2/28/2025	12 Months Ending 2/28/2026	26 Months Ending 2/28/2026
1	Contractor	$ 309,154	$ 116,682	$ 425,836	$ 547,655	$ 973,491
2	Labor	$ 2,363	$ 436	$ 2,799	$ 4,420	$ 7,219
3	Materials	$ 776	$ 193	$ 969	$ 1,057	$ 2,025
4	Business Expenses	$ 1,756	$ 759	$ 2,515	$ 2,783	$ 5,298
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 25,255	$ 6,174	$ 31,430	$ 44,571	$ 76,000
	Total	$ 339,304	$ 124,244	$ 463,548	$ 600,484	$ 1,064,032

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Amount	(h) Actual Amount
1	2023	Coal Generation	Campbell 3	Routine	Environmental	SCR Catalyst Management	$ 2,303	$ 2,254
2	2023	Gas Generation	Covert Commons	Routine	Condition-based	Long Term Service Agreement - Running capital contract	$ 9,761	$ 9,182
3	2023	Gas Generation	Covert Commons	Non-Routine	Acquisition	Covert Generating Facility Acquisition	$ 815,000	$ 663,142
4	2023	Gas Generation	Covert Commons	Non-Routine	Regulatory	Covert Information Technology Room		$ 2,060
5	2023	Gas Generation	Covert Commons	Non-Routine	Regulatory	Covert Security and Network		$ 2,208
6	2023	Gas Generation	Covert Commons	Non-Routine	Condition-based	Covert Spare generator stepup transformer		$ 1,723
7	2023	Gas Generation	Jackson Site Commons	Routine	Condition-based	GE Long Term Service Agreement FFH	$ 9,571	$ 8,908
8	2023	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	7EA Casing replacement & Hot section overhaul	$ 2,088	$ 2,558
9	2023	Gas Generation	Jackson Site Commons	Non-Routine	Condition-based	HRSG Burner Element Isolation Valves Addition	$ 2,021	$ 2,210
10	2023	Gas Generation	Zeeland Site Commons	Routine	Condition-based	Long Term Service Agreement - Running Capital Contract	$ 9,520	$ 6,657
11	2023	Gas Generation	Zeeland Site Commons	Routine	Condition-based	LTSA - Extras not included in contract (cranes, mobile equipment)	$ 2,900	$ 15,184
12	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Zeeland Unit 1 Generator Step Up Transformer Rewind	$ 4,604	$ 2,328
13	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Multimedia filtration Pilot Skid		$ 2,442
14	2023	Gas Generation	Zeeland Site Commons	Non-Routine	Condition-based	Unit 5 generator stepup transformer Rewind		$ 13,885
15	2023	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Cooling Tower Rebuild	$ 3,971	$ 5,439
16	2023	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Karn 3 Exciter Rewind		$ 1,039
17	2023	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Boiler Plant Heating Project		$ 4,836
18	2023	Hydro Generation	Croton	Non-Routine	Condition-based	Croton 1&2 Wicket Gate		$ 4,330
19	2023	Hydro Generation	Five Channels	Non-Routine	Regulatory	Headgate Project	$ 1,982	$ 1,686
20	2023	Hydro Generation	Hardy	Non-Routine	Regulatory	Auxiliary Spillway Remediation	$ 3,459	$ 2,591
21	2023	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Hodenpyl 1 Generator Rewind	$ 3,101	$ 3,285
22	2023	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Spillway Hoist Replacement	$ 2,864	$ 2,153
23	2023	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Replace Lower Penstock Expansion Joint Chamber Waterstop	$ 2,425	$ 3,328
24	2023	Hydro Generation	Ludington Site Commons	Non-Routine	Safety	Powerhouse Roof Wearing Surface and Weather Proofing Replacement	$ 2,724	$ 2,021
25	2023	Hydro Generation	Mio	Non-Routine	Safety	Electrical Safety Project	$ 1,086	$ 2,376
26	2023	Hydro Generation	Rogers	Non-Routine	Condition-based	Unit 4 Generator Rewind	$ 2,600	$ 1,965
27	2023	Hydro Generation	Webber	Non-Routine	Infrastructure	Webber Left Downstream Spillway Abutment Wall	$ 2,975	$ 3,974
28	2023	Renewables	Solar Commons	Non-Routine	New Generation	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	$ 61,930	$ 58,570
29	**Total 2023 Projects**						**$ 946,885**	**$ 832,335**

Note:
(1) Projected amounts were taken from Case No. U-21389

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Line No.	**Calendar Period**	**Tier 1 Portfolio**	**Tier 2 Portfolio**	**Project Type**	**Project Classification**	**Full Internal Budget Approval**	**Work Item Description**	**Projected Amount**
1	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Purchase of site spare generator stepup transformer	$ 1,000
2	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Cooling Tower Gearboxes	$ 1,162
3	Bridge Period	Gas Generation	Covert	Routine	Environmental	Approved	SCR/CO Catalyst Replacement - Unit 2	$ 1,042
4	Bridge Period	Gas Generation	Covert	Routine	Environmental	Approved	SCR/CO Catalyst Replacement - Unit 3	$ 1,042
5	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Approved	Units 1-3 Emerson DCS Evergreen	$ 1,041
6	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Approved	Long Term Service Agreement - Running capital contract	$ 20,400
7	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Approved	GE LTSA Historical Extra Work Expected	$ 2,908
8	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Approved	GE Long Term Service Agreement FFH	$ 12,338
9	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Unit 5 generator step up transformer rewind	$ 5,547
10	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	$ 20,356
11	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	$ 3,925
12	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Approved	Zeeland Long Term Service Agreement - Running Capital Contract	$ 9,520
13	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Heat recovery steam generator Casing Replacement	$ 2,098
14	Bridge Period	Gas/Oil Generation	Karn 3	Routine	Condition-based	Approved	Karn 3 distributed control system Evergreen	$ 1,507
15	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Approved	Karn 3 Cooling Tower Internal Structure Replacement	$ 6,000
16	Bridge Period	Gas/Oil Generation	Karn commons	Routine	Condition-based	Approved	Karn 3&4 Sync Wire Replacement	$ 1,260
17	Bridge Period	Gas/Oil Generation	Karn 3	Routine	Condition-based	Approved	Karn Unit 3 Combustion Air Heater	$ 2,200
18	Bridge Period	Gas/Oil Generation	Karn 4	Routine	Condition-based	Approved	Karn 4 DCS Evergreen	$ 1,363
19	Bridge Period	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Approved	Boiler Plant Heating Project	$ 1,760
20	Bridge Period	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Alcona Core Wall Remediation Project	$ 9,025
21	Bridge Period	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Alcona Artesian Design Study	$ 1,358
22	Bridge Period	Hydro Generation	Allegan	Non-Routine	Condition-based	Approved	Allegan 1 Wicket Gate Replacement	$ 1,900
23	Bridge Period	Hydro Generation	Foote	Non-Routine	Condition-based	Approved	Foote Spillway Hoist Replacement	$ 1,585
24	Bridge Period	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Auxiliary Spillway Replacement	$ 2,946
25	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl - Emergency Spillway Project	$ 1,064
26	Bridge Period	Hydro Generation	Hodenpyl	Non-Routine	Condition-based	Approved	Hodenpyl Spillway Hoist Replacement	$ 5,108
27	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Powerhouse Left Embankment Retaining Wall	$ 2,006
28	Bridge Period	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Probable Maximum Flood Project	$ 2,466
29	Bridge Period	Hydro Generation	Tippy	Non-Routine	Condition-based	Approved	Tippy - Unit 1 Thrust Bearing Replacement	$ 1,900
30	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 1-6 distributed control system Control Relay Replacement	$ 1,648
31	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington lower penstock expansion joint Chamber water stop replacement	$ 2,716
32	Bridge Period	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	$ 141,387
33	Bridge Period	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2022 Bid Event (Spring Creek)	$ 108,185
34	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Armstrong Battery Energy Storage System (IIJA Grant App)	$ 3,931
35	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Iosco Battery Energy Storage System (IRP)	$ 15,990
36	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Weadock Battery Energy Storage System (IRP)	$ 19,751
37	**Total Bridge Period Projects**							**$ 419,434**

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21585
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Date: May 2024

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2023 through 2026
($000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Full Internal Budget Approval	(g) Work Item Description	(h) Projected Amount
1	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Purchase of site spare GSU	$ 4,500
2	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Approved	Cooling Tower Gearboxes	$ 1,039
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Units 1-3 Emerson DCS Evergreen	$ 2,449
4	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Long Term Service Agreement - Running capital contract	$ 14,700
5	Test Year	Gas Generation	Covert	Non-Routine	infrastructure	Approved	Office Space Consumers Energy Warehouse with Loading Dock	$ 1,817
6	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Netmation (MHPSA Operating System & 4S) - Unit 2	$ 1,458
7	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Netmation (MHPSA Operating System & 4S) - Unit 3	$ 1,504
8	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 1 - LTSA Capital - Extra work not included in contract	$ 1,438
9	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 2 - LTSA Capital - Extra work not included in contract	$ 12,610
10	Test Year	Gas Generation	Covert	Routine	Condition-based	Approved	Unit 3 - TSA Capital - Extra work not included in contract	$ 10,610
11	Test Year	Gas Generation	Jackson	Routine	Condition-based	Approved	GE Long Term Service Agreement FFH	$ 11,117
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	$ 25,744
13	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	$ 4,275
14	Test Year	Gas Generation	Zeeland	Routine	Condition-based	Approved	Long Term Service Agreement - Running Capital Contract	$ 8,181
15	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Purchase of Site Spare Generator Step up transformer	$ 6,449
16	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Generator Rewinds	$ 2,174
17	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Approved	Phase II Turbine Replacements	$ 1,884
18	Test Year	Gas/Oil Generation	Karn	Routine	Condition-based	Approved	Karn 4 Replacement of Ductwork Insulation and Lagging	$ 4,800
19	Test Year	Gas/Oil Generation	Karn	Non-Routine	Condition-based	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$ 1,900
20	Test Year	Hydro Generation	Fleet	Non-Routine	infrastructure	Approved	Fleet - Build new machine shop	$ 2,100
21	Test Year	Hydro Generation	Alcona	Non-Routine	Regulatory	Approved	Auxiliary Spillway Improvements	$ 2,500
22	Test Year	Hydro Generation	Cooke	Non-Routine	Condition-based	Approved	Head Gate Replacement Project	$ 1,803
23	Test Year	Hydro Generation	Five Channels	Non-Routine	Condition-based	Approved	Five Channels Unit 1 Wicket Gate	$ 3,753
24	Test Year	Hydro Generation	Five Channels	Non-Routine	Condition-based	Approved	Five Channels Spillway Hoist Replacement	$ 1,190
25	Test Year	Hydro Generation	Five Channels	Non-Routine	Safety	Approved	Five Channels Trash Rack Ergonomics Project	$ 1,675
26	Test Year	Hydro Generation	Foote	Non-Routine	Safety	Approved	Foote ADA Ramp Investigation and replacement	$ 1,463
27	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Auxiliary Spillway Replacement	$ 53,854
28	Test Year	Hydro Generation	Hardy	Non-Routine	Regulatory	Approved	Hardy Splash Wall Replacement	$ 2,760
29	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl - Emergency Spillway Project	$ 1,654
30	Test Year	Hydro Generation	Hodenpyl	Non-Routine	Regulatory	Approved	Hodenpyl Downstream Wall	$ 3,772
31	Test Year	Hydro Generation	Loud	Non-Routine	Condition-based	Approved	Loud Unit 2 Wicket Gates Replacement	$ 3,000
32	Test Year	Hydro Generation	Rogers	Non-Routine	Regulatory	Approved	Rogers Probable Maximum Flood Project	$ 3,207
33	Test Year	Hydro Generation	Tippy	Non-Routine	Safety	Approved	Tippy - Electrical Safety Project	$ 1,591
34	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 1-6 DCS Control Relay Replacement	$ 4,772
35	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Governor Replacement	$ 1,916
36	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington 480 Volt Motor Control Centers for DLC	$ 1,566
37	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Intake Gate and Gate House Mechanical Replacement	$ 1,666
38	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Approved	Ludington Commons Station Power Transformer Life Cycle Management	$ 1,150
39	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	$ 128,907
40	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2022 Bid Event (Spring Creek)	$ 122,819
41	Test Year	Renewables - IRP	Solar	Non-Routine	New Generation	Approved	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	$ 24,233
42	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Armstrong Battery Energy Storage System (IIJA Grant App)	$ 4,878
43	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Iosco Battery Energy Storage System (IRP)	$ 29,867
44	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Approved	Weadock Battery Energy Storage System (IRP)	$ 44,176
45	**Total Test Year Projects**							**$ 568,922**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Availability Projections
March 1, 2025 Through February 28, 2026

Case No.: U-21585
Exhibit No.: A-42 (RTB-2)
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	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Plant**	**Actual ROR 2019-2023**	**Projected ROR**	**Periodic Factor**	**Projected Availability**	**Actual NEV 2019-2023**
1	Campbell 1	16.89%	16.00%	66.30%	28.30%	$94,251,307
2	Campbell 2	30.27%	15.00%	0.00%	85.00%	$83,293,257
3	Campbell 3	14.29%	8.00%	0.00%	92.00%	$347,202,422
4	Karn 3	38.70%	18.00%	11.78%	72.34%	-$8,065,128
5	Karn 4	24.76%	18.00%	12.88%	71.44%	-$10,424,299
6	Ludington 1	5.06%	3.50%	10.96%	85.92%	$19,165,396
7	Ludington 2	4.94%	3.50%	8.49%	88.30%	$454,083
8	Ludington 3	6.81%	3.50%	18.36%	78.79%	-$57,815
9	Ludington 4	7.75%	3.50%	18.36%	78.79%	-$298,851
10	Ludington 5	7.34%	3.50%	23.29%	74.03%	$1,941,254
11	Ludington 6	4.97%	3.50%	20.00%	77.20%	$16,330,522
12	Hydros	9.48%	5.60%	16.14%	79.16%	$47,444,888
13	Zeeland CC	7.48%	4.00%	12.60%	83.90%	$183,763,696
14	Zeeland 1A	3.89%	4.00%	9.59%	86.79%	$16,822,762
15	Zeeland 1B	4.45%	4.00%	9.59%	86.79%	$19,956,480
16	Jackson	8.22%	4.50%	14.52%	81.63%	$158,401,855
17	Covert 1	4.09%	7.00%	13.15%	80.77%	$17,911,397
18	Covert 2	6.25%	7.00%	11.23%	82.55%	$13,462,508
19	Covert 3	6.08%	7.00%	19.18%	75.16%	$17,995,020
20	Cross Winds EP					$123,677,013
21	Lake Winds EP					$43,059,634
22	Gratiot Farms Wind(2)					$34,390,807
23	Crescent Wind(2)					$34,096,348
24	Heartland (3)					$425,801
25	Solar Gardens (1)					$1,140,655

(1) Reflects NEV for 2020-2023 only.
(2) Reflects NEV for 2022-2023 only.
(3) Reflects NEV for 2023 only.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2023 through February 2026
($000's)

Case No.: U-21585
Exhibit No.: A-43 (RTB-4)
Page: 1 of 3
Witness: RTBlumenstock
Date: May 2024

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2023	(c) Projected Bridge Period 14 Months Ending 02/28/2025	(d) Projected Test Year 12 Months Ending 02/28/2026
1	**BASE O&M**	$ 93,864	$ 121,165	$ 78,063
2	**ADJUSTED O&M**			
3	Environmental Operations	$ 9,225	$ 6,965	$ 2,584
4	Major Maintenance	$ 15,759	$ 37,035	$ 31,203
5	Retention & Separation	$ 17,348	$ 11,158	$ 4,621
6	**TOTAL O&M**	**118,848.652**	**165,164.491**	**111,850.689**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
For the Years 2023 through February 2026
($000's)

Case No.: U-21585
Exhibit No.: A-43 (RTB-4)
Page: 2 of 3
Witness: RTBlumenstock
Date: May 2024

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	Description	2023 Actual	Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2023	Merit & Inflation 12 Mos Ending Dec 31, 2024	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2024	Merit & Inflation 12 Mos Ending Dec 31, 2025	Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025	Merit & Inflation 2 Mos Ending 2/28/2026	Other Adjustments	Projected O&M 12 Mos Ending 2/28/2026
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Total O&M	**118,849**	**118,849**	**2,852**	**121,701**	**2,677**	**124,378**	**456**	**-12,983**	**111,851**
1	Labor	74,659	74,659	1,792	76,451	1,682	78,133	286	-8,156	70,264
2	Material	5,604	5,604	134	5,738	126	5,865	22	7,742	13,628
3	Contractor	14,481	14,481	348	14,828	326	15,154	56	-9,936	5,274
4	Non-Labor Overheads	0	0	0	0	0	0	0	0	0
5	Non-Labor Other	24,105	24,105	579	24,683	543	25,226	92	-2,633	22,685

Notes

		2024	2025	2026
*	Annual merit increase			
	Annual merit increase	2.4%	2.2%	2.2%
	Number of months in the period	12	12	2
	Pro-rated merit increase	2.4%	2.2%	0.4%
	Annual inflation rates per WP-JCA-51			
	Annual inflation rates	2.4%	2.2%	2.2%
	Number of months in the period	12	12	2
	Pro-rated inflation rate	2.4%	2.2%	0.4%

Consumers Energy Company
Summary of the Generation Major Maintenance O&M Expense
For the Years 2023 through February 2026
($000's)

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2023	(c) Projected Bridge Period 14 Months Ending 02/28/2025	(d) Projected Test Year 12 Months Ending 02/28/2026
	Major Maintenance			
1	Campbell 1&2	$ 1,054	$ 2,189	$ 268
2	Campbell 3	$ 995	$ 2,413	$ 277
3	Karn 1&2	$ 67	$ 202	$ 100
4	Karn 3&4	$ 216	$ 2,314	$ 2,502
5	Classic 7	$ 52	$ 264	$ 218
6	Zeeland Generating Station	$ 3,121	$ 5,959	$ 5,232
7	Jackson Generating Station	$ 2,822	$ 5,256	$ 3,852
8	Covert Generating Stations	$ 2,144	$ 5,919	$ 7,706
9	Ludington	$ 2,533	$ 4,924	$ 4,445
10	Hydros	$ 2,756	$ 6,990	$ 5,776
11	Solar	$ -	$ 432	$ 677
12	Admin & Other	$ -	$ 175	$ 150
13	**TOTAL Major Maintenance**	**$ 15,759**	**$ 37,035**	**$ 31,203**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-7
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 12

Blumenstock 2025 Direct Testimony

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for	)	Case No. U-21870
the generation and distribution of	)	
electricity and for other relief.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2025

Q. Please state your name and business address.

A. My name is Richard T. Blumenstock, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with Consumers Energy?

A. I am currently the Executive Director of Electric Supply Engineering. I began employment at the Company in May 1994 in the electric transmission planning area where I performed planning studies on the Company's distribution and transmission systems. In April 2002, I was assigned to the electric operations area where I oversaw engineering operations for the distribution and transmission systems. In August 2009, I was assigned to the fuel supply area where I oversaw the Company's purchasing and transport functions for fuel for electric generation. In June 2011, I assumed additional responsibilities including oversight of the Company's interaction in the Midcontinent Independent System Operator, Inc. ("MISO") markets; wholesale settlements and transactions functions; Power Supply Cost Recovery ("PSCR") activities; and planning for electric supply necessary to satisfy customers' energy and capacity needs. In September 2019, I assumed the role of Executive Director of Electric Planning, overseeing the company-wide efforts for all electric planning. In September 2022, I assumed my current position as Executive Director of Electric Supply Engineering.

Q. What are your responsibilities as Executive Director of Electric Supply Engineering?

A. My responsibilities as Executive Director of Electric Supply Engineering include oversight of all activities associated with planning and design for the Company's electric generation portfolio.

Q. What is your formal educational experience?

A. I received a Bachelor of Science degree in 1992 and a Master of Science degree in 1994, both in Electrical Engineering from Michigan Technological University.

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

A. Yes, I provided testimony in the following MPSC cases:

- Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;

- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;

- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan ("IRP") pursuant to MCL 460.6t and for other relief;

- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;

- Case No. U-21224: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-21389: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and

- Case No. U-21585: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

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

A. The purpose of my direct testimony is to support the Generation Department ("Generation") requests in this case, and to provide other information that the Company has committed to provide. Toward that end I will:

- Describe Consumers Energy's oil-, and gas-fired generation assets, and its hydroelectric and renewable generation assets, including their projected retirement dates;

- Support the Company's generation asset strategy to focus continued investment in those generating units (Zeeland Generating Station ("Zeeland Plant", "ZGS" or "Zeeland"), New Covert Generating Facility ("Covert Plant" or "Covert"), and Jackson Generating Station ("Jackson Plant", "JGS" or "Jackson")) which provide the most long-term economic benefit for customers;

- Support the periodic outage plans and the Generation Unit Availability and Random Outage Rate ("ROR") projections for oil- and gas-fired peaking generation, and hydroelectric power generation, for the projected test year ending April 30, 2027;

- Support the reasonableness and prudence of the capital expenditures for oil- and gas-fired peaking generation, and hydroelectric power generation for the historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;

- Support the reasonableness and prudence of the Operation and Maintenance ("O&M") oil- and gas-fired peaking generation, and hydroelectric power for historical test year ended December 31, 2024, the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026, and the projected test year ending April 30, 2027;

- Support the reasonableness and prudence of the O&M expenses for the D.E. Karn ("Karn") Units 1 and 2 retention and separation incentives for the historical test year ended December 31, 2024;

- Support the reasonableness and prudence of the O&M expenses for the J.H. Campbell ("Campbell") Units 1, 2, and 3 retention and separation incentives for the historical test year ended December 31, 2024, and the 16-month bridge period beginning January 1, 2025 and ending April 30, 2026;[1] and

- Describe the environmental regulations with which the Company's electric generating fleet must comply.

Q. How is your direct testimony related to the direct testimony of other Company witnesses?

A. Company witness Megan L. Metz's testimony supports the PSCR costs planned to be incurred, taking into account the periodic outages identified in Exhibit A-41 (RTB-1) and

[1] On May 23, 2025, the U.S. Department of Energy issued Order No. 202-25-3 ("DOE Order") requiring the Company to "take all measures necessary to ensure that the Campbell Plan is available to operate" through August 21, 2025. The DOE Order also specifies that, at the conclusion of this period, the Company will be permitted "sufficient time for orderly ramp down . . . consistent with industry practices." The Company is currently evaluating the impact of the DOE Order on its decommissioning plan and other aspects of this rate case. Until the Company is able to complete its evaluation, my testimony continues to reflect assumptions about the Campbell Plant's retirement before the date of the DOE Order.

the generating unit availability projections in Exhibit A-42 (RTB-2). Company witness Metz also supports the capacity value of the Company's generation assets for the seasonal construct in the MISO Planning Resource Auction ("PRA") in Table 2.

Company witness Thomas P. Clark supports the competitive solicitation process and timeline associated with the proposed battery energy storage system ("BESS") projected capital expenditures.

Company witness Patrick D. Daly supports the regulatory asset balances and amortization for the recovery of retention and separation expenses at Karn and Campbell sites in his direct testimony.

Company witness Heidi J. Myers supports the continued deferral of the revenue requirement for river hydroelectric generating plant ("River Hydro") capital expenditures as well as the proposed O&M deferral for River Hydro in her direct testimony.

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

A. Yes, I am sponsoring the following exhibits:

Exhibit A-41 (RTB-1)		Generating Unit Periodic Outages;
Exhibit A-42 (RTB-2)		Generating Unit Availability Projections;
Exhibit A-12 (RTB-3)	Schedule B-5.2	Summary of Actual and Projected Electric Capital Expenditures for the Years 2024 through April 2027;
Exhibit A-43 (RTB-4)		Summary of the Generation O&M Expense for the Years 2024 through February 2027;
Exhibit A-44 (RTB-5)		Zeeland Phase I and II Gas Turbine Upgrade Concept Approvals;
Exhibit A-45 (RTB-6)		Jackson Site Spare GSU Transformer Concept Approval;

Exhibit A-46 (RTB-7)	Covert Load Commutated Inverter Static Frequency Converter Replacements Concept Approval;
Exhibit A-47 (RTB-8)	Covert Site Spare GSU Transformer Concept Approval;
Exhibit A-48 (RTB-9)	Covert Control System Project Concept Approval;
Exhibit A-49 (RTB-10)	Covert Units 1 through 3 Emerson DCS Evergreen Concept Approval;
Exhibit A-50 (RTB-11)	Karn Unit 4 ID Fan Inlet Damper Replacements Concept Approval; and
Exhibit A-51 (RTB-12)	Karn Units 3 & 4 Combustion Air Heater Replacement Concept Approval.

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

A. Yes.

Q. How are the following sections of your direct testimony organized?

A. My direct testimony is divided into four sections. Section I will present exhibits and supporting testimony on the Company's generating assets, its generating asset strategy, and its generating asset projected performance metrics. Included in this section is a discussion on the status of the Company's River Hydro strategy and its projected impact on the Company's cost projections. Section II will describe the environmental regulations with which the Company's electric generating fleet must comply. Section III presents exhibits and supporting testimony for the historical and projected generation capital expenditures. Section IV will present exhibits and supporting testimony for the historical and projected generation O&M expense. This section will include support of the reasonableness and prudence of the O&M expenses for both the Karn Units 1 and 2 retention and separation incentives, the reasonableness and prudence of the O&M expenses for Campbell Units 1, 2, and 3 retention and separation incentives, and the Company's proposal for River Hydro O&M expense.

SECTION I

GENERATION ASSETS

Q. Please provide an overview of the Company's generation assets.

A. As of February 24, 2025, the Company's total projected owned generation assets for the 2025/2026 Planning Year had a Generator Verification Test Capacity ("GVTC") of 5,722 MW, comprised of the following units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	NET GENERATING CAPABILITY (MW)
OIL OR GAS FIRED					
Covert	Covert, MI	2004	21	2040	1090
DE Karn 3	Essexville, MI	1975	50	2031	602
DE Karn 4	Essexville, MI	1977	48	2031	587
Zeeland CC	Zeeland, MI	2002	23	2041	534
Zeeland 1A	Zeeland, MI	2002	23	2041	158
Zeeland 1B	Zeeland, MI	2002	23	2041	157
Jackson	Jackson, MI	2002	23	2041	531
HYDROELECTRIC					
Alcona	Alcona County, MI	1924	101	n/a	3
Allegan	Allegan County, MI	1936	89	n/a	1
Cooke	Iosco County, MI	1911	114	n/a	7
Croton	Newaygo County, MI	1907	118	n/a	2
Five Channels	Iosco County, MI	1912	113	n/a	6
Foote	Iosco County, MI	1918	107	n/a	3
Hardy	Newaygo County, MI	1931	94	n/a	33
Hodenpyl	Wexford County, MI	1925	100	n/a	4
Loud	Iosco County, MI	1913	112	n/a	5
Mio	Oscoda County, MI	1916	109	n/a	1
Rogers	Mecosta County, MI	1906	119	n/a	2
Tippy	Manistee County, MI	1918	107	n/a	6
Webber	Ionia County, MI	1907	118	n/a	1
RENEWABLES					
Lake Winds	Mason County, MI	2012	13	2042	101
Cross Winds (Phase I)	Tuscola County, MI	2014	11	2044	231
Cross Winds (Phase II)	Tuscola County, MI	2018	7	2048	
Cross Winds (Phase III)	Tuscola County, MI	2018	7	2048	
Crescent Wind	Jonesville, MI	2021	4	2051	166
Gratiot Farms Wind	Alma, MI	2021	4	2051	150
Heartland Farms Wind Park	Ithaca, MI	2024	1	2054	200
Solar Gardens- GVSU	Grand Rapids, MI	2016	9	2046	3
Solar Gardens- WMU	Kalamazoo, MI	2016	9	2046	1
Cadillac Solar Garden	Cadillac, MI	2021	4	2051	0.5
Circuit West	Grand Rapids, MI	2019	6	2049	0.5
ENERGY STORAGE					
Ludington Units 1-6**	Ludington, MI	1973	52	2069	1138 (owned share)

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("LPS" or "Ludington") Units 1 through 6?

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous Electric Rate Case, Case No. U-21585?

A. No. There have been no changes to the retirement dates for the Company's owned generation units. The only change to the Company's owned generation units was the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

Q. How will the Company continue to meet its load requirements with the retirement of the Campbell units?

A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn Units 3 and 4, and the addition of Zonal Resource Credits ("ZRCs") by June 1, 2025, through a one-time solicitation approved as part of the Settlement Agreement.

Q. What capacity resources were identified through the one-time solicitation?

A. The IRP one-time solicitation resulted in the execution of 3 separate contracts totaling 400 MW of BESS projects. The Company's January 12, 2024, filing of the Tibbits Energy Storage, LLC Power Purchase Agreement ("PPA"), a 100-MW battery storage project which the MPSC approved in its April 11, 2024 Order. The term of the PPA is 20 years, with deliveries expected to commence by May 31, 2025 with an expected PPA termination date of May 31, 2045. The IRP one-time solicitation also resulted in the Company's May 13, 2024 filing of the Century Oaks Energy Storage LLC PPA, a 200-MW battery storage energy project. The Century Oaks Energy Storage LLC PPA also has a term of 20 years with deliveries expected to commence by May 31, 2026, and an expected PPA termination date of May 31, 2046. Finally, the IRP one-time solicitation resulted in the Company's September 27, 2024, filing of the Voyager Energy Storage LLC PPA, a 100-MW battery storage project which the MPSC approved in its November 21, 2024 Order. The Voyager Energy Storage LLC PPA also has a term of 20 years and, with deliveries expected to commence by May 31, 2027, with an expected PPA termination date of May 31, 2047. Each of these contracts were filed in MPSC Case No. U-21090.

Q. What other actions has the Company taken to ensure it has sufficient capacity to reliably serve its customers?

A. In addition to the 400 MW of BESS PPAs, the Company has executed several agreements with Midland Cogeneration Venture ("MCV") for short-term capacity measured in ZRCs. On November 21, 2024, in Case No. U-21666, the Company received MPSC approval of a contract for 100 ZRCs for the 2025, 2026, and 2027 planning years. On March 21, 2025, in Case No. U-21827, the Company received MPSC approval of a contract for 175 ZRCs for the 2025 and 2026 planning years. The contract was the result of a reverse capacity auction that was conducted by an independent administrator on July 18, 2024.

GENERATION ASSET STRATEGY

Q. Please describe the Company's asset strategy for its generating units.

A. The Company's generation asset strategy is focused on delivering safe, reliable, affordable, and clean energy and capacity for its customers. This strategy will be implemented within the construct of the Company's clean energy goals and its IRPs and renewable energy plans, as approved by the MPSC.

Q. How does the Company's generation asset strategy apply to the Company's various generating units?

A. Consistent with Consumers Energy's strategy, the Company's generating asset investments will focus on onboarding renewable energy resources, including BESSs as well as those generating assets that provide the most economic benefit to customers through their energy and capacity value in the respective MISO markets. In addition, the Company will also ensure it complies with all state and federal regulations.

Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP and the Company's 2024 Amended Renewable Energy Plan, the Company will concentrate investment in new renewable energy resources and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit. During 2024, the Company's Covert, Zeeland and Jackson Plants produced over 70% of the net energy value and approximately 56% of the capacity value realized by the Company's electric generating fleet (excluding renewables). As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2024 net energy and capacity value by asset type:

FIGURE 1

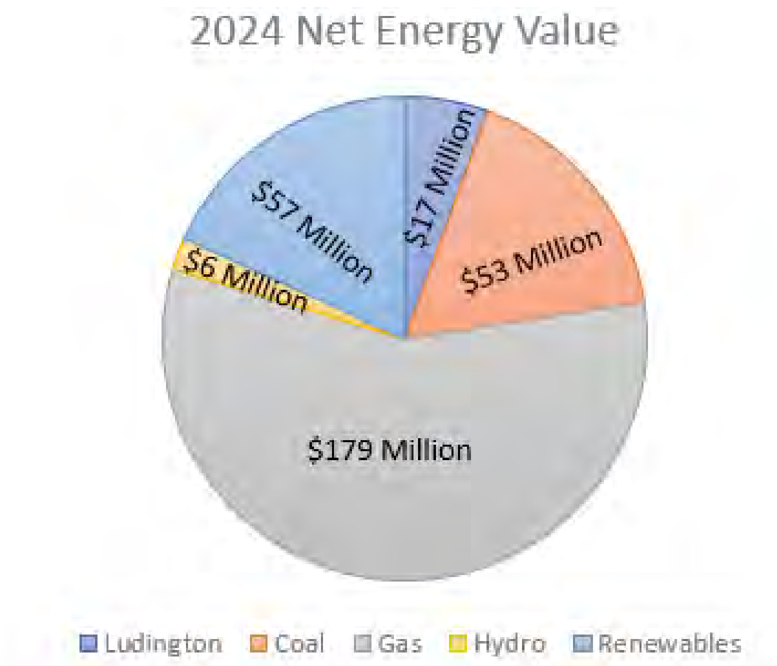
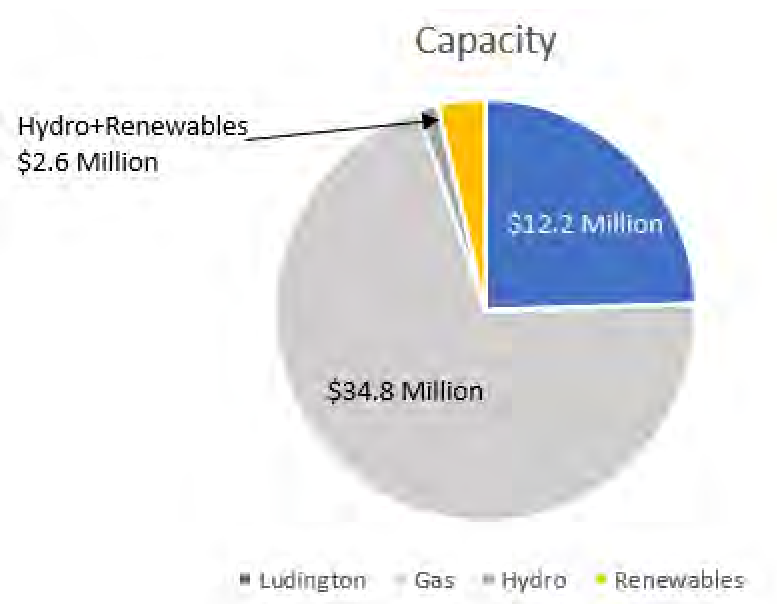


FIGURE 2



Q. How does the Company's generation asset strategy apply to the balance of the Company's generating units?

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value, and consistency with the Company's currently approved IRP expected retirement dates. The Company will continue to maintain its generating units, including the River Hydro facilities, to ensure safe and environmentally compliant operations. I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony describing projected generating unit availability.

Q. Has the Company's existing generation asset strategy changed as a result of the 2023 Michigan energy legislation?

A. Not materially. While Public Act ("PA") 235 of 2023 requires the Company to achieve a 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed to an aggressive transition in its generation asset portfolio mix through its 2018 and 2021 IRPs. Pursuant to PA 235 of 2023, the Company filed a Renewable Energy Plan amendment on November 15, 2024, which reflected its plans to comply with the new renewable energy laws.

With respect to the clean energy portion of the 2023 Michigan energy legislation, the details for the Company's compliance with the clean energy portfolio targets contained in that legislation will be reflected in the Company's proposed course of action in its next IRP to be filed in 2026.

PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS, AND NET ENERGY VALUE

Q. Please describe Exhibit A-41 (RTB-1).

A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending April 30, 2027 for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's peaking generation, and hydraulic power generation for the projected test year beginning May 1, 2026 and ending April 30, 2027. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

Q. What factors cause an increase or decrease in ROR?

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates decreases ROR. Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

Q. How are ROR projections for the Generating units developed?

A. The ROR projections for the projected test year ending April 30, 2027 were developed from the five-year (2020-2024) average. These five-year averages were then adjusted to reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2), column (b).

Q. Please define PF.

A. PF is a measure of the percent of lost availability that results from planned outages, planned outage extensions, planned de-rates, and planned de-rate extensions. Planned derates can be taken for a variety of reasons, including the performance of necessary maintenance work which does not require an outage to perform, or the management of emissions at gas generation facilities to stay within environmental limits.

Q. What strategy does the Company employ to minimize the impact of planned outages on its customers?

A. Consistent with the Company's generation asset strategy, the Company endeavors to schedule planned generating unit outages during periods in which the margin between the generating unit production cost and the projected MISO energy market price is lowest. This strategy results in creating greater total NEV as I will discuss in more detail later in this direct testimony. In general, the projected MISO energy market pricing is lower in the shoulder months of spring and fall due to historically lower demand. However, with the introduction of seasonal capacity in the MISO market, the Company will also consider the impact of outage scheduling on capacity accreditation for the four capacity seasons. Company witness Metz describes seasonal capacity in more detail in her testimony.

Q. Please define Projected Availability.

A. Projected Availability is a measure of the percent of time that a generating unit or category of generating units is projected to be available to generate electricity.

Q. How is Projected Availability determined for each generating unit or category of generating units?

A. The Projected Availability for each generating unit or category of generating unit is calculated as (100% - PF) * (100% – ROR). Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

Q. How does the Company's generation asset strategy inform Projected Availability?

A. As I previously discussed, the Company's generation asset strategy and associated generation investment will focus on each unit's ability to provide economic value to customers through the unit's ability to produce energy and capacity value in the respective MISO markets. As such, those generating units or category of generating unit providing the greatest amount of economic value to customers will be targeted to achieve the highest projected availabilities.

Q. How can the Company impact Projected Availability for a generating unit?

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

Q. Does the Company attempt to maximize availability for all its generating units or category of generating units?

A. No. Consistent with the Company's generation asset strategy, the Company focuses on sustaining availability for those generating units which provide the greatest economic benefit to customers through the energy value provided. The Company's generating units get dispatched by MISO as part of the MISO energy market. Based upon the Company's projected dispatch likelihood for each unit, the Company will rank the generating units from highest economic value to least economic value, and manage the PF and the ROR, and therefore the unit's Availability, to allow for the highest customer value. Or, stated differently, the PF and ROR values may be allowed to be higher (lower unit Availability) for the lower economic value units, and will be managed to lower values (higher unit Availability) for higher economic value units.

Q. How does the Availability projection reflect the customer benefit?

A. An improvement in Availability can translate to a customer benefit in several ways. The immediate benefit is that the generating unit or the category of generating unit is available for dispatch for a greater number of hours throughout the year, likely leading to increased generation, and consequently higher NEV, on an annual basis. Additionally, higher availability increases the ZRCs, increasing the capacity value of the unit.

Q. How does the Company measure the customer benefit resulting from increased generation?

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-42 (RTB-2), column (f), which identifies five-year (2020-2024) actual NEV amounts.

Q. What can the Company do to positively affect NEV?

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

Q. Does the cost of production vary for the Company's generating units?

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for its customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

Q. Why is the measurement of NEV important to the Company and its customers?

A. Positive NEV reflects a direct and immediate reduction to customer power supply costs and consideration of NEV provides a basis for making operational and financial decisions in order to maximize the customer value of the generating unit.

Q. What is another measure the Company uses to evaluate economic projects for its generating units?

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the current capacity value of the Company's generating units based upon the summer season results in the 2024-2025 PRA for Zone 7. Company witness Metz discusses the capacity value of the Company's generating units in the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC[1] MW	MISO SUMMER SAC[2] MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[3]	CAPACITY VALUE ZONE 7 (75% CONE)[4]
OIL OR GAS FIRED					
Covert	Covert, MI	1089.5	952.9	$ 10,434,255	$ 70,178,191
DE Karn 3	Essexville, MI	602.1	367	$ 4,018,650	$ 27,028,435
DE Karn 4	Essexville, MI	586.8	542.3	$ 5,938,185	$ 39,938,748
Zeeland CC	Zeeland, MI	533.8	501.5	$ 5,491,425	$ 36,933,952
Zeeland 1A	Zeeland, MI	157.6	153.3	$ 1,678,635	$ 11,290,079
Zeeland 1B	Zeeland, MI	156.7	153	$ 1,675,350	$ 11,267,985
Jackson	Jackson, MI	531	508.6	$ 5,569,170	$ 37,456,845
HYDROELECTRIC					
Alcona	Alcona County, MI	2.7	2.7	$ 29,565	$ 198,847
Allegan	Allegan County, MI	1.2	1.2	$ 13,140	$ 88,376
Cooke	Iosco County, MI	7.2	6.8	$ 74,460	$ 500,799
Croton	Newaygo County, MI	2.1	2.1	$ 22,995	$ 154,659
Five Channels	Iosco County, MI	6.2	5.8	$ 18,615	$ 427,152
Foote	Iosco County, MI	2.7	2.8	$ 30,660	$ 206,211
Hardy	Newaygo County, MI	33.3	32.4	$ 354,780	$ 2,386,162
Hodenpyl	Wexford County, MI	4.1	4.1	$ 44,895	$ 301,953
Loud	Iosco County, MI	5	4.8	$ 52,560	$ 353,505
Mio	Oscoda County, MI	1.3	1.3	$ 14,235	$ 95,741
Rogers	Mecosta County, MI	2	2.1	$ 22,995	$ 154,659
Tippy	Manistee County, MI	5.8	5.8	$ 63,510	$ 427,152
Webber	Ionia County, MI	1	1	$ 10,950	$ 73,647
RENEWABLES					
Lake Winds	Mason County, MI	100.8	17.9	$ 196,005	$ 1,318,281
Cross Winds (Phase I, II, III)	Tuscola County, MI	230.6	52.9	$ 579,255	$ 3,895,924
Crescent Wind	Jonesville, MI	166	24.4	$ 267,180	$ 1,796,986
Gratiot Farms Wind	Alma, MI	149.7	36.3	$ 397,485	$ 2,673,385
Heartland Farms Wind Park	Ithaca, MI	200	31.5	$ 344,925	$ 2,319,879
Solar Gardens- GVSU	Grand Rapids, MI	3	1.7	$ 18,615	$ 125,200
Solar Gardens- WMU	Kalamazoo, MI	1	0.6	$ 6,570	$ 44,188
Cadillac Solar Garden	Cadillac, MI	0.5	0.2	$ 2,190	$ 14,729
Circuit West	Grand Rapids, MI	0.5	0.2	$ 2,190	$ 14,729
ENERGY STORAGE					
Ludington Units 1-6	Ludington, MI	1138.0 (owned share)	1110	$ 12,154,500	$ 81,748,128

1 ISAC = Intermediate seasonal accredited capacity
2 SAC = Seasonal accredited capacity and is converted from ISAC based upon offered availability during RA and non-RA hours
3 2024-2025 Summer PRA Settlement price of $30/MW-day for Zone 7.
4 2024-2025 PRA 75% CONE price of $269.03/MW-day for Zone 7.

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units, as well as maintain capacity accreditation. Critical reliability investments required to keep the units available will be included in the plan.

Q. How will the Company's generation asset strategy for Karn Units 3 and 4 impact their projected performance?

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c). During the five-year historical period from 2020 through 2024, Karn Unit 3 had an ROR of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (b).

Q. How is this strategy reflected in the Projected Availability for Karn Units 3 and 4 in the test year?

A. The projected availabilities for Karn Units 3 and 4 in the test year are 69.13% and 72.97%, respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 15.69%, as shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned outages for the test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22, 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 7 and 9. The availability for Karn Unit 4 reflects a projected ROR of 18.00% and a PF of 11.01%, as shown on Exhibit A-42 (RTB-2), line 2, columns (c) and (d). The planned outages for the test year are scheduled to begin on October 12, 2026 and last for 30 days, and March 22, 2027 and last for 29 days, as reflected on Exhibit A-41 (RTB-1), lines 8 and 10.

Q. How does the Projected Availability for Karn Units 3 and 4 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2020 through 2024, Karn Unit 3 had a NEV of -$8.1 million and Karn Unit 4 had a NEV of -$10.4 million. The 2024 NEV for each of these units was -$1.7 million and -$0.4 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is $4.0 million for Karn Unit 3 and $5.9 million for Karn Unit 4. The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is $27.0 million for Karn Unit 3 and $39.9 million for Karn Unit 4.

Q. Please provide an overview of the generation asset strategy for the Zeeland Plant.

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to increase economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets and the turbine projects discussed later in this direct testimony aim to increase customer value. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve dispatch and reliability, such as the turbine projects, are included in the plan as they provide value to customers.

Q. How will the Company's generation asset strategy for the Zeeland Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42 (RTB-2), lines 10 through 12, column (c). During the five-year historical period from 2020 through 2024, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown on Exhibit A-42 (RTB-2), lines 10 through 12, column (b).

Q. How is this strategy reflected in the Projected Availability for the Zeeland Plant in the test year?

A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the Zeeland Plant in the test year is 87.80%, as shown on Exhibit A-42 (RTB-2), line 10, column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability is based upon a projected ROR of 4.0% and a PF of 8.54%, as shown on Exhibit A-42 (RTB-2), line 10, columns (c) and (d). The Projected Availabilities for each of the simple cycle generating units at the Zeeland site in the projected test year are 89.98%, as shown on Exhibit A-42 (RTB-2), lines 11 and 12, column (e). Each of the Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 6.27%, as shown on Exhibit A-42 (RTB-2), lines 11 and 12, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending April 30, 2027, however there are several shorter duration outages of 14 days, each scheduled in May and October, 2026. There are no outages greater than 28 days scheduled for the Zeeland simple cycle units (Units 1 and 2) in the projected test year ending April 30, 2027, however there is a 13-day outage on each unit in the spring of 2026, a 3-day outage on each unit in September 2026, and a 14-day outage on each unit in the spring of 2027. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Zeeland Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 10 through 12, column (f), during the five-year historical period from 2020 through 2024, the Zeeland Plant provided a total NEV of $220.5 million. The 2024 NEV for Zeeland was $49.4 million.

Q. Please quantify the capacity value for the Zeeland Plant.

A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is $8.8 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is $59.5 million.

Q. Please provide an overview of the generation asset strategy for the Jackson Plant.

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer’s perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

Q. How will the Company’s generation asset strategy for the Jackson Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company’s generation asset strategy is expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on Exhibit A-42 (RTB-2), line 13, column (c). During the five-year historical period from 2020 through 2024, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit A-42 (RTB-2), line 13, column (b).

Q. How is this strategy reflected in the Projected Availability for the Jackson Plant in the test year?

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 92.09%, as shown on Exhibit A-42 (RTB-2), line 13, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 3.57%, as shown on Exhibit A-42 (RTB-2), line 13, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in the test year, however a short 12.5-day outage is scheduled April 2027. In addition, several derates are scheduled to perform inspections and maintenance on various generating units in September and October 2026 and March of 2027.

Q. How does the Jackson Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 13, column (f), during the five-year historical period from 2020 through 2024, the Jackson units provided a total NEV of $158.4 million. The 2024 NEV for the Jackson Plant was $24.1 million.

Q. Please quantify the capacity value for the Jackson Plant.

A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is $5.6 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is $37.5 million.

Q. How will the Company's generation asset strategy for the Covert Plant impact its projected performance?

A. It is anticipated that site performance will remain relatively consistent with past performance under different ownership. Based upon the Covert Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 7.00% for all three units at the Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 14 through 16, column (c).

Q. How is this strategy reflected in the Projected Availability for the Covert Plant in the test year?

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 74.12% to 87.54%, as shown on Exhibit A-42 (RTB-2), lines 14 through 16, column (e). The Covert Unit 1 unit availability of 74.12% is based upon projected ROR of 7.00% and a PF of 20.30%, as shown on Exhibit A-42 (RTB-2), line 14, columns (c) and (d); the Covert Unit 2 unit availability of 87.54% is based upon projected ROR of 7.00% and a PF of 5.87%, as shown on Exhibit A-42 (RTB-2), line 15, columns (c) and (d); and the Covert Unit 3 unit availability of 84.80% is based upon projected ROR of 7.00% and a PF of 8.81%, as shown on Exhibit A-42 (RTB-2), line 16, columns (c) and (d). The Company will conduct major inspections at all three of the Covert Units during the bridge period/test year. The planned outage for the test year for Covert Unit 1 is scheduled to begin on September 1, 2026 and last for 59 days as reflected on Exhibit A-41 (RTB-1), line 2. The planned outage for the bridge period for Covert Unit 2 began on March 1, 2025 and ended on May 25, 2025. The planned outage for the bridge period/test year for Covert Unit 3 is scheduled to begin on March 15, 2026 and last for 59 days, as reflected on Exhibit A-41 (RTB-1), line 1. These outages are scheduled for periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

Q. How does the Covert Plant Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 14 through 16, column (f), during the 19-month historical period beginning June 1, 2023 through December 31, 2024, the Covert units provided a total NEV of $49.4 million. The 2024 NEV for the Covert Plant was $24.1 million.

Q. Please quantify the capacity value for the Covert Plant.

A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is $10.4 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is $70.2 million.

Q. Please provide an overview of the Company's generation asset strategy for the River Hydro units.

A. The strategic plan for the Company's River Hydro units is currently predicated on operating the units consistent with the Company's Federal Energy Regulatory Commission ("FERC") project licenses. Continued operation of these facilities is assumed in the Company's current IRP that was approved by the MPSC in Case No. U-21090. These units deliver customer value by providing renewable energy and capacity. River Hydro facilities also provide value to their surrounding local communities and to the state of Michigan in the form of recreational opportunities, natural preservation, and environmental benefits.

The overall long-term objective for the River Hydro units is to maintain safe and reliable River Hydro sites for our customers, to ensure compliance with FERC obligations and other regulatory requirements, and to continue providing valuable benefits to local residents, surrounding communities, and the state of Michigan.

Q. Is it possible the River Hydro facilities could be retired early or not be relicensed?

A. Yes. The Company is always evaluating its long-term generation strategy, including for the River Hydro units. As a result of a Settlement Agreement in the Company's most recent general electric depreciation case, Case No. U-20849 and a filing extension approved in Case No. U-21783, Consumers Energy will present retirement and decommissioning analysis for its River Hydro facilities to the Commission by the end of 2025. The Company will evaluate each facility and determine the best path forward from the perspective of Consumers Energy, its customers, and the State of Michigan. Although this analysis has not been completed, it is clear that compliance with FERC requirements will require continued investment in safety and reliability upgrades to operate these River Hydro facilities well into the future.

Q. Has the Company presented any River Hydro capital investments in this electric rate case?

A. No. In the March 21, 2025 Final Order in the Company's 2024 Electric Rate Case No. U-21585, the Commission found that the "company may use deferred regulatory accounting of the revenue requirement on actual capitalized investments incurred subject to review in the company's next electric rate case."[2] The Commission went on to state that this accounting authority does not relieve the Company of meeting the evidentiary burden

[2] Case No. U-21585, March 21, 2025 Final Order, p 157.

for its investments. As such, the Company has not presented any River Hydro projects for the bridge period and test year and intends to seek recovery in a future regulatory proceeding.

Q. Has the Company presented actual River Hydro investments for the historical test year?

A. No. As discussed in more detail in the direct testimony of Company witness Myers, the Company is requesting the continuation of the deferral through the test year of this rate case and, as such, has not presented its actual 2024 River Hydro capital expenditures. This is due to the continuing uncertain future of the River Hydros. The Company's potential future scenarios for the River Hydros include divestiture, decommissioning, and relicensing and continuing operation.

Q. What is the status of the Request for Proposals ("RFP") for River Hydro divestiture?

A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities on February 15, 2024. As part of the first phase of the RFP, which involved bidder screening based on, among other things, qualifications and indicative pricing, the Company received responses to the RFP on March 15, 2024. The Company evaluated the bids and moved to the second phase of the RFP in April of 2024.

Q. Please discuss Phase 2 of the RFP for River Hydro divestiture.

A. Phase 2 involved initially engaging with seven selected entities in due diligence, negotiations, and potential sale agreement(s). Due diligence was completed during the summer of 2024, at which time negotiations began with selected bidders. The Company's negotiations are continuing with the expectation of reaching a contract mid-year 2025.

Q. What are the next steps following the execution of a contract for divestiture?

A. To the extent that the Company can reach an agreement on their divestiture, the Company would file an application with the MPSC and FERC for approval of the sale and related agreements.

Q. How will the Company move forward if divestiture fails or is rejected by the Commission?

A. To the extent that the Company is unable to reach an agreement for sale of the River Hydros or a potential sale is rejected, the Company would revisit the decision to relicense or decommission the River Hydros, with the intention of making a decision as soon as possible following a decision to not divest.

Q. Is the Company requesting the recovery of O&M expense for the River Hydros in this proceeding?

A. Yes. The Company has reflected River Hydro O&M expense in my Exhibit A-43 (RTB-4) for the historic year, the 16-month bridge period, and the test year. The Company will discuss its proposal for future O&M expense later in this direct testimony.

Q. How will the Company's generation asset strategy for the River Hydro units impact their projected performance?

A. It is anticipated that future River Hydro unit performance will remain relatively consistent with current River Hydro unit performance, provided that necessary investments are made to ensure safe and reliable operation. In other words, as assumed in Consumers Energy's current IRP, the Company currently expects its River Hydro facilities can continue to deliver reliable clean energy to customers while maintaining their long record of operational, safety, and environmental performance. Based upon the River Hydro unit major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 5.60% for the River Hydro units in the projected test year ending April 30, 2027, as shown on Exhibit A-42 (RTB-2), line 9, column (c). During the five-year historical period from 2020 through 2024, the River Hydro units had an ROR of 9.48% for all units, as shown on Exhibit A-42 (RTB-2), line 9, column (b).

Q. How is this strategy reflected in the projected availability for the River Hydro units in the projected test year?

A. The projected availability for all of the River Hydro units in the projected test year is 89.38%, as shown on Exhibit A-42 (RTB-2), line 9, column (e). The Projected Availability for the River Hydro units reflects a projected ROR of 5.60% and a PF of 5.32%, as shown on Exhibit A-42 (RTB-2), line 9, columns (c) and (d). These projections reflect (i) a 109-day planned outage at Cooke Unit 1 for replacement of the downstream right retaining wall, (ii) a 270-day planned outage at Five Channels Unit 2 for wicket gate replacement, (iii) a 270-day planned outage at Croton Unit 3 for unit overhaul, (iv) a 249-day planned outage at Webber Unit 1 for generator rewind and unit overhaul, (v) a 270-day planned outage at Loud Unit 1 for wicket gate replacement, (vi) a 82-day planned outage at Tippy Units 1-3 for an electric safety upgrade, and (vii) a 270-day planned outage at Croton Unit 4 for periodic inspection and thrust bearing inspection.

Q. How does the River Hydro unit Projected Availability translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), line 9, column (f), during the five-year historical period from 2020 through 2024, the River Hydro units which are registered with MISO

(Alcona, Croton, Hardy, Hodenpyl, and Tippy) provided a total NEV of $44.9 million. The 2024 NEV for the River Hydro units registered with MISO was $6.6 million.

Q. Please quantify the capacity value for the River Hydro units?

A. As reflected in Table 2, the capacity value of the River Hydro units based upon the settlement price for MISO Zone 7 in the 2024-2025 MISO PRA is $0.8 million and the River Hydro unit hypothetical capacity value based upon 75% of Cost of New Entry for Zone 7 in the 2024-2025 PRA is $5.4 million.

Q. Please provide an overview of the generation asset strategy for Ludington.

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process.

Q. How will the Company's generation asset strategy for Ludington impact its projected performance?

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (c). During the five-year historical period from 2020 through 2024, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (b).

Q. How do the Ludington Units factor into the Company's future renewable energy strategy as outlined in the IRP?

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio since it can deliver a significant amount of energy in a short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy. However, defective and non-conforming work performed by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully provide these intended benefits over its remaining life.

Q. How is this strategy reflected in the Projected Availability for Ludington in the test year?

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 0.00% to 84.01%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 3.50% and PFs ranging from 12.94% to 100.00%, as shown on Exhibit A-42 (RTB-2), lines 3 through 8, columns (c) and (d). There are four major outages planned for the Ludington units in the test year: a 274-day outage on Ludington Unit 3 beginning on September 2, 2026 as presented on Exhibit A-41 (RTB-1), line 3; a 49-day outage on Ludington Unit 6 beginning on September 8, 2026 as presented on Exhibit A-41 (RTB-1), line 4; a 42-day outage on Ludington Unit 5 beginning on September 10, 2026 as presented on Exhibit A-41 (RTB-1), line 5; and a 683-day outage on Ludington Unit 4 beginning on October 19, 2026 as presented on Exhibit A-41 (RTB-1), line 6. In addition, shorter outages on all six Ludington units are scheduled throughout the test year, primarily in the spring and fall. These outages will be used, in part, to perform cooling water strainer cleaning, install and remove the barrier net, and perform other necessary inspections. To the extent possible, the outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

Q. Please provide an overview of the generation asset strategy for the Renewable Energy Assets.

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, continues to be primarily driven by the Company's MPSC-approved 2021 IRP Settlement Agreement. Consistent with the IRP, all previously identified wind assets were in service throughout 2024. For solar, the Company plans to continue to add incremental solar resources in accordance with its Clean Energy Plan and Renewable Energy Plans. These solar resources are being added pursuant to the Company's annual IRP solicitations, as discussed in more detail later in this direct testimony. In addition, the Company anticipates that it will also add wind and solar assets for the foreseeable future in support of the Company's Voluntary Green Pricing Program, and their costs will be reconciled through the Company's Renewable Energy Plan.

Q. Is the Company requesting recovery of renewable energy assets in this proceeding?

A. No. The Commission approved the movement of cost recovery for renewable energy resources to the Company's Renewable Energy Plan in its March 21, 2025 Order in Case

No. U-21585. As such, all costs for renewable energy assets will be presented and reconciled in renewable energy plans.

Q. How will the enactment of PA 235 of 2023 impact the Company's future renewable energy portfolio?

A. As previously discussed in this direct testimony, the Company filed a Renewable Energy Plan Amendment on November 15, 2024. PA 235 of 2023 has established both renewable and clean energy targets for the future beginning with a renewable energy compliance target of 50% in 2030. The newly passed law became effective on February 27, 2024 and provides for the utilization of renewable energy assets from anywhere within the MISO footprint.

The Company's Renewable Energy Plan Amendment proposes the addition of 2,800 MW of renewable energy wind resources and an additional 1,000 MW of renewable energy solar resources, over and above the Company's glidepath established in its 2021 IRP settlement.

Q. How do the Company's renewable assets translate into customer value?

A. Similar to the Company's River Hydro units, the production cost of the Company's renewable energy assets is zero. As such, all energy sold into the MISO energy market has value provided that the MISO locational marginal prices are positive. Additionally, renewable assets provide the Company's customers with renewable energy credits. As reflected on Exhibit A-42 (RTB-2), lines 17 through 18, column (f), during the five-year historical period from 2020 through 2024, the Cross Winds Energy Park and the Lake Winds Energy Park provided a total NEV of $166.7 million. As reflected on Exhibit A-42 (RTB-2), lines 19 through 20, column (f), during the three-year historical period from 2022 through 2024, Gratiot Farms Wind and Crescent Wind provided total NEV of $68.5 million. Heartland Farms Wind Park began commercial operation on December 29, 2023, and as reflected on Exhibit A-42 (RTB-2), line 21, column (f), generated $0.4 million in NEV in 2023. The Company began to measure the NEV for its solar assets in 2020 and the 2020 through 2024 NEV for its Solar Garden Assets totaled $1.1 million.

Q. Please quantify the capacity value for renewable energy assets.

A. As reflected in Table 2, the renewable asset capacity value based upon the settlement price for Zone 7 in the 2024-2025 PRA is $0.4 million and the renewable asset hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2024-2025 PRA is $2.5 million.

Q. Why have you included a hypothetical capacity value for each of the generating units or category of generating units?

A. I have included these hypothetical values to reflect the capacity values that the Company uses in its capacity planning process. Company witness Metz provides additional information regarding the capacity value of the Company's generation assets in MISO's PRA as well as the projected capacity margin in future years for Zone 7.

Q. How will the Company determine the reasonableness and prudence of additional investments in the electric generating fleet?

A. Additional investment in the remaining units over and above those necessary to maintain safety and regulatory compliance would require some level of economic benefit for customers, otherwise the investment does not make sense. The generating unit periodic outage plans, projected RORs and, ultimately, projected availability for each generating unit or category of generating units reflects the Company's generation asset strategy.

SECTION II

ENVIRONMENTAL REGULATIONS

OVERVIEW

Q. Can you please list the environmental regulations with which Consumers Energy is required to comply and that are relevant to expenditures for which the Company is seeking recovery in this case?

A. Yes. The Company's fossil-fueled Electric Generating Units ("EGUs") are subject to numerous complex and overlapping air, water, and waste regulations.

CURRENT (ON-GOING) ENVIRONMENTAL COMPLIANCE

Environmental Regulations – Air Quality

Q. Describe Consumers Energy's Existing Air Quality Compliance Strategy ("AQCS").

A. Over the past decade, Consumers Energy has had expenditures to comply with a variety of air quality-related regulations, including the Cross State Air Pollution Rule, the Mercury and Air Toxics Standards, and the Michigan Mercury Rule, among others. The background and purpose of each such rule has been discussed in the testimony of prior rate cases, including Case No. U-17735. To comply with these regulations, Consumers Energy created the AQCS. Cost recovery reflecting the Company's AQCS was approved in the November 19, 2015 Order in the Company's 2014 Electric Rate Case (Case No. U-17735). This AQCS has prudently ensured compliance with applicable state and federal air-quality related regulations. The Company's actions and investments to achieve such compliance have been performed in a manner which has minimized, to the extent reasonably possible, the associated costs for customers. The investments made to ensure environmental compliance have allowed the continued operation of coal generation while the Company transitions to carbon-free generation sources like solar.

Q. Are there any updates to the air quality-related regulations for which the Company's existing AQCS complies?

A. Yes. In April 2022 the Environmental Protection Agency ("EPA") proposed the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" under the "good neighbor" provision of the Clean Air Act. The EPA's rule was finalized, effective March 15, 2023 but this revision was stayed in 2024 and the prior 2017 Cross-State Air Pollution Rule ("CSAPR") remains in effect. On March 12, 2025, U.S. EPA Administrator Lee Zeldin announced the agency will undertake action to "end the Good Neighbor Plan." It is most likely that CSAPR will remain in effect. The Company will continue to monitor the rule and evaluate various options for compliance as needed.

Q. What are the capital investments and/or O&M expenses the Company is seeking to recover in this case that are specifically related to air quality control?

A. Any O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibit A-43 (RTB-4).

Q. Are you seeking recovery of any expenses related to the regulation of greenhouse gases from EGUs?

A. No, not at this time. On June 19, 2019, the EPA finalized three rulemakings: (i) repeal of the Clean Power Plan; (ii) issuance of the final Affordable Clean Energy ("ACE") Rule and; (iii) issuance of new Clean Air Act ("CAA") section 111(d) regulations. In May 2024, EPA issued a Final GHG standards for new and existing fossil fuel-fired EGUs under Section 111 of the CAA and the ACE Rule was repealed. These new requirements do not impact the Company's fleet due to the planned retirement date for our last coal units.

Existing gas-fired combustion turbine units are not subject to this rule and therefore those Company units are also not subject to this rule. On March 12, 2025, EPA Administrator Lee Zeldin announced the agency will undertake actions "reconsidering regulations on power plants (Clean Power Plan 2.0)" which could imply that these regulations will be revised at some point in the future.

Environmental Regulations and Compliance Strategy – Waste

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed and signed into law. Section 2031 of the legislation provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has information gathering and enforcement authorities to enforce the CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows Department of Environment, Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Environmental Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

Q. What are the capital and/or O&M investments Consumers Energy is seeking to recover in this case that are specifically related to RCRA compliance and/or overall CCR Management?

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The Cost of Removal ("COR") and/or O&M required for the management of CCRs under the RCRA that the Company is seeking to recover can be found in Exhibits A-139 (JJK-3) and A-43 (RTB-4). The COR expenses represent historical expenses only. Separately, there are closure activities that will continue throughout the bridge period and test year and beyond; however, those expenses are COR and are not included in this filing.

<u>Environmental Regulations and Compliance Strategy – Water</u>

Q. Can you please describe the relevant parts of the Steam Electric Effluent Guidelines ("SEEG") as related to wastewater management?

A. On April 24, 2024, EPA finalized a supplemental rulemaking to strengthen discharge limits for Flue Gas Desulfurization ("FGD") wastewater, bottom ash transport water, Combustion Residual Leachate ("CRL"), and legacy wastewaters. FGD and legacy wastewaters are not and will not be generated at Consumers Energy locations. Campbell will be retiring in 2025 and will comply with the cessation of coal combustion by 2028 subcategory for bottom ash transport water. CRL discharge limits will impact the Campbell dry ash landfill where the Company is completing a capital project to install a deep injection well to address this issue. Paired with the 2024 RCRA rule, there is risk at the J.C. Weadock ("Weadock"), Karn, B.C. Cobb ("Cobb"), and J.R. Whiting ("Whiting") sites. The 2024 RCRA rule does not allow free liquid in closed ash landfills, but it also does not define what free liquid is.

If the 2024 RCRA rule were to require installation of dewatering wells in closed landfills, any wastewater generated would likely be classified as unmanaged CRL subject to arsenic and mercury limits and require treatment prior to surface water discharge.

Q. What are the capital and/or O&M investments Consumers Energy is seeking to recover in this case that are specifically related to RCRA compliance and/or overall wastewater management?

A. The Company is seeking to recover costs for the installation of a deep well to be used for wastewater disposal at the Campbell facility. The Campbell facility will cease generation in June 2025 and on-site operations will cease by the end of 2025. Due to wastewater generated during decommissioning, the sitewide National Pollutant Discharge Elimination System ("NPDES") permit will remain open through demolition. Campbell has an active landfill with leachate which requires treatment/disposal. After on-site operations end, the flow characteristics of the Campbell facility will change and there will be a need to manage leachate differently as the current outfall location will no longer be available for use. SEEG rules require zero liquid discharge of CRL no later than December 31, 2029; however, because of the change in flow characteristics by the end of 2025, the Company considered several options to address the ongoing leachate water, including transport for offsite disposal, offsite treatment, onsite treatment and onsite disposal. Ultimately, onsite disposal via a deep-injection well was selected and is currently being permitted by EGLE and EPA. The Company also submitted a NPDES permit application revision on November 7, 2024. Please refer to page 8, line 27, and page 9, line 22 of Exhibit A-12 (RTB-3), Schedule B-5.2 for projected capital expenditures in the bridge period and test year.

SECTION III

GENERATION CAPITAL EXPENDITURES

OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation for the historical year 2024 through the projected test year - 12 months ending April 30, 2027. Exhibit A-12 (RTB-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2024, the Projected 16-month Bridge Period beginning January 1, 2025 and ending April 30, 2026, and the projected test year beginning May 1, 2026 and ending April 30, 2027. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but are presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically, page 7 of this exhibit presents capital projects for the Historical Period ended December 31, 2024; page 8 of this exhibit presents capital projects for the Projected 16-month Bridge Period beginning January 1, 2025 and ending April 30, 2026; and page 9 of this exhibit presents capital projects for the projected test year ending April 30, 2027.

Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9?

A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type, the generation unit, project type, project classification, project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly; whereas non-routine projects are typically undertaken once every 10 years or longer. The budget approval reflects the status of internal approval for the project, including projected cost amount. Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost; whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project projected amount.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $145.252 million for the historical test year ended December 31, 2024 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b); $275.408 million in the projected 16-month Bridge Period ending April 30, 2026 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and

$188.638 million in the projected test year ending April 30, 2027 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

Q. Has the Company included any contingency in the requested capital expenditures for Generation?

A. No. The Company no longer includes contingency in its generation projects.

Q. Please explain how the Company prioritizes its capital investments within Generation.

A. In evaluating capital investments, the Company's first priority is addressing safety, regulatory, compliance, and continued operation related projects. These projects are considered a mandatory cost of doing business. Safety, regulatory, compliance, and continued operation-related projects provide economic value to customers in that they allow the units to remain in service and avoid potential derates and/or shutdown due to an intervention by various regulators including Occupational Safety and Health Administration ("OSHA"), EGLE, the EPA, and FERC. In order to minimize the impact of these projects on customers, the Company utilizes a least cost/best fit ("LCBF") analysis for the investments necessary to satisfy service quality, safety, and federal and state policy requirements.

Q. How does the Company determine whether other projects get approved for funding?

A. In accordance with the Company's generation asset strategy for each generating unit or category of generating units, economic projects that are expected to reduce ROR, maintenance cost or heat rate, all else being equal, are evaluated to ensure that their implementation results in a net benefit to the customer. For a project to receive approval for implementation, the projected benefits of the work must have a greater value than the cost of implementing the project. In other words, the implementation of the project should, at a minimum, result in a marginal customer benefit.

Q. How does the Company evaluate other capital investments, such as economic projects?

A. The Company uses two financial measures, Internal Rate of Return ("IRR") and Present Value Ratio ("PVR"), as a means to evaluate and prioritize projected economic projects within Generation. A complex financial model was developed in-house that allows the Company to calculate and measure the numerous changes that result when improvements (both O&M and Capital) are made to its rate-based generating units.

Q. Does the Company calculate IRRs or PVRs for all projects?

A. No. The Company calculates IRRs or PVRs for economic projects that are not considered required but would yield net benefits to customers. Projects required for regulatory, compliance, and/or continued operations are reviewed to assure that the project is cost effective and results from a reasonable evaluation of alternatives, but because the project must be done for compliance and continued operation, IRR or PVR may not be calculated. When evaluating project alternatives related to regulatory, compliance, and/or continued operations, IRRs or PVRs may be used to rank alternatives.

Q. Please explain what you mean by projects for continued operations.

A. Projects for continued operations refers to projects which are necessary to allow the generating unit to continue to operate through its retirement date. Alternatives for projects necessary for continued operation will generally be evaluated based upon LCBF. For this evaluation, one of the alternatives will include a decision to not perform the project and either retire the unit earlier than projected or operate the unit at a permanent derate.

Q. How does the Company evaluate customer benefits associated with generation-related capital investments?

A. The Company uses replacement power cost estimates and PSCR impacts when evaluating customer benefits. The Company also evaluates ROR and heat rate improvements, which result in increased generation and/or lower cost generation.

Q. How does the Company evaluate historical events which have impacted availability?

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending April 30, 2027.

Q. Does the Company evaluate customer benefits associated with Outage Schedules?

A. Yes, the Company uses historical market prices to evaluate timing around outages in an effort to ensure the unit is available during periods in which market pricing is projected to be high.

Q. Is it possible that the Company could experience changes to its scheduled outages and forecasted capital expenditures in the future?

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2023. A review of the outage schedule used in this case identifies ten scheduled outages that begin in May 2026 (20 months after the schedule was approved) and run through April 30, 2027, 31 months later. During each of these ten scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

Q. Are there other reasons why outage schedule changes occur?

A. Yes. Some of the reasons why outage schedule changes occur are: contractor availability, parts availability, changes in regulations, design changes, outage scope changes, changes in unit condition, and spot market prices. It is critical to point out that disallowance of projected capital expenditures in electric rate cases leads to the cancellation of work scope and outage plans, thus pushing needed investment to the future, continuing risk with plant operations, and increasing customer cost due to lower availability.

Q. Can you provide an example of when circumstances changed?

A. Yes. The Company's fall 2023 outages for Karn Units 3 and 4 were originally scheduled from October 1, 2023 through November 18, 2023. The Karn Unit 3 and 4 outages were not performed due to availability of materials for the major work that was planned. Due to the uncertainty of the retirement of Karn Units 3 and 4 as proposed in the Company's 2021 IRP, the preparation for these outages was not complete, including material delivery. As such the planned work was deferred to 2024.

Q. Please describe how the Company determines its generation projected capital expenditure amounts.

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant and reliable operations of the Company's electric generating fleet. Projected capital investments are informed by historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's electric generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

Q. How are projects identified that are discussed later in this direct testimony?

A. Generation System Planners assess the equipment performance and compare that assessment with the generation asset strategy for the generating unit. Upon identification of a potential project, the Planner will complete a project initiation document ("PID"). This document defines the issue, alternatives considered for resolution, intended benefits or consequences avoided, and suggested timing and a cost estimate. The document is reviewed by multiple groups for alignment and ultimately routed for approval for inclusion in the Long-Term Financial Plan ("LTFP"). PIDs entered into the LTFP will typically be scheduled three to five years in the future to align with outages and provide the project execution teams ample time to plan and engineer.

Q. How were the projected capital expenditure amounts developed for each of the projects discussed later in this direct testimony?

A. Each project begins with the creation of a PID. The Planner will provide an initial cost estimate for the project within the PID. The Planner utilizes past experience, contractor cost estimates, internal estimates, Original Equipment Manufacturer ("OEM") data, and studies to provide the best estimate of the costs. This activity typically takes place three to five years prior to the start of project execution.

Q. How are PIDs related to Concept Approval Documents ("CADs")?

A. The PID is the mechanism utilized to allow projects to be considered for the LTFP. Once the project is included in the LTFP and the project is within a year of start of execution, the CAD is created. The CAD is templated from the PID and updated as necessary. The CAD is then routed for approval to the designated level of management based on project amount and, once approved, the project will be initiated.

Q. Do adjustments to the projected capital investment amounts for each of the projects occur prior to project implementation?

A. Yes. As the project team progresses through the life cycle of a project, there are multiple opportunities to better define project costs. Activities such as detailed engineering, bidding, contractor involvement, and construction all allow for budgets to be better defined. As this definition evolves, the projected capital investments are updated accordingly.

Q. How does the Company account for uncertainties in its cost projections?

A. When forecasting and budgeting for the Company's generation projects, the Company accounts for the uncertainty of less mature estimates by including contingency in its cost estimates. For purposes of this rate case filing, the Company has already removed the contingency component of its generation project cost estimates before filing the case since it has been disallowed in the past. The Company also utilizes industry standard cost estimating practices that involve class estimates having a prescribed range of potential cost outcomes based on estimate accuracy. The Commission has historically disallowed costs above the lower range for certain projects and cost estimate classes.

Q. What impact does this have on the Company's ability to fund needed generation capital projects?

A. If the Commission disallows both the contingency amount included in the project forecasts and an amount consistent with the bottom end of the range of estimate accuracy, it is virtually certain to underfund the Company's generation capital projects.

<u>2024 HISTORICAL TEST YEAR CAPITAL EXPENDITURES</u>

Q. How does the 2024 actual capital expenditure amount of $145.252 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21585?

A. In Case No. U 21585, the Company requested $339.304 million for the 12 months ended December 31, 2024. The 2024 actual capital expenditure amount of $145.252 million is $194.052 million less than the projected amount.

Q. What is the basis for the gap in projected versus actual spending?

A. The reduction in the Company's actual capital expenditure amount is primarily attributable to the removal of the capital expenditures for IRP solar projects (Muskegon, Spring Creek, Mustang Mile, and Washtenaw) and the reduction in investment in the BESS projects. The Company withdrew the requested recovery of the IRP solar generation projects from Case No. U-21585 and has instead sought to recover them in its amended renewable energy plan

Case No. U-21816. The removal of the investment for these projects for the 12-month period ending December 31, 2025 reduced the projected capital expenditures by $130.597 million.

In addition, the Company identified delays in the commercial operation dates ("CODs") for the BESS projects. The projected investment amount for the 12 months ended December 31, 2024 was $39.672 million and the actual capital expenditure amount was $22.942 million, a difference of $16.730 million. The CODs for the Weadock and Iosco projects were pushed out beyond the test year in Case No. U-21585 so there was no impact to the revenue requirement in the final order.

Also, as previously discussed in this direct testimony, the actual 2024 capital expenditures do not include any River Hydro investment. The total investment on the River Hydros for the 12 months ending December 31, 2024 was projected to be $38.052 million and the actual investment was only $33.933 million. Several parties to the Company's 2024 electric rate case recommended complete disallowance of the entire River Hydro investment and, as such, the Company managed its investment in 2024.

Finally, the actual capital expenditures for Ludington for the 12-month period ended December 31, 2024 came in at $3.857 million versus the projected amount of $8.717 million. The total investment amount for Ludington was over $20 million, however a portion of the investment was recorded as a regulatory asset.[3]

[3] See the February 28, 2025 report in Case No. U-21310.

Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, compare with the 14-month bridge capital projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8?

A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the bridge period projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, reveals that there are eleven projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, which were not reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8. In addition, there were fourteen projects for the 14-month bridge period that were reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7. The River Hydro projects were not considered in this evaluation due to their removal.

Q. Please discuss the 14-month bridge period capital projects that were included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, due to the fact that their actual 2024 capital expenditure amount was less than $1 million, the project was disallowed, reduced in cost or removed, or not pursued in 2024. As previously discussed, the entire amount of River Hydro investment was deferred and, as such, is not presented on the Company's Exhibit A-12 (RTB-3), Schedule B-5.2. In addition, the entire amount of investment for the Covert Long-Term Service Agreement ("LTSA") extra work was disallowed. The disposition of the other capital projects which are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2 is provided below:

Below is a list of projects for which the Company either removed or did not reflect in the revenue requirement due to their COD being beyond the test year:

Project Description	Projected Amount
Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	$ 141,387
Solar - 2022 Bid Event (Spring Creek)	$ 108,185
Armstrong Battery Energy Storage System (IIJA Grant App)	$ 6,341

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21585 were less than $1 million:

Project Description	Projected Amount ('000)	Reduced Amount ('000)
Covert Purchase of site spare generator stepup transformer	$ 1,000	$ (27)
Covert Cooling Tower Gearboxes	$ 1,162	$ 872
Covert SCR/CO Catalyst Replacement - Unit 2	$ 1,042	$ 142
Covert SCR/CO Catalyst Replacement - Unit 3	$ 1,042	$ 142
Karn Unit 3 Combustion Air Heater	$ 2,200	$ 214
Ludington lower penstock expansion joint Chamber water stop replacement	$ 2,716	$ 556

Below is a discussion of the remaining million-dollar projects whose actual 2024 capital expenditures were less than projected:

- Covert Units 1 through 3 Emerson Digital Control System (“DCS”) Evergreen ($1,041,250). The projected 2024 spend for this project was only $551,500 with the largest portion of the spend reflected in 2025 including the last two months of the bridge period. The actual spend in 2024 was $530,441 so the actual spend is relatively on target. The remaining spend of $2,156,101 in the bridge period and $967,800 in the test year will complete the project;

- Jackson Long Term Service Agreement Extra Work Expected ($1,366,114). During 2024, the Company spent a total of $330,371 on this project, primarily due to moving S2 Nozzle Assy work from 2024 to 2025 because of the delay in material delivery from General Electric. $2,115,001 is planned for the bridge period ending April 30, 2026, and only $0.315 million is planned for the test year ending April 30, 2027;

- Zeeland Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($8,631,164) and LTSA Extras not included in the contract. The total spend for these projects and the long-term service agreement in 2024 was $21,506,968. The total projected amount for these three projects for the 14-month bridge period was $29,505,861 with $9,941,250 of that projected amount reflected in January and February of 2025. As such, the actual spend for all the work associated with the LTSA was greater than the projected amounts;

- Karn Unit 4 DCS Evergreen ($1,449,204). The Company spent $125,388 in 2024 versus the projected 2024 amount of $1,363,000. The Company underspent on the project because it didn’t employ Emerson Field Engineering Service time, rather the Company completed many of the items internally and, therefore, avoided a portion of the investment; and

- Ludington 1-6 distributed control system control relay replacement ($1,623,526). During 2024 the Company spent $670,551 of the total 2024 projected amount of $1,214,360. The remaining bridge period amount was forecast to be spent in January and February of 2025. The Company is projected to spend $3,608,477 in the 16-month projected bridge period and $2,906,676 in the projected test year. The project was intentionally delayed in order to align it with the large corrective project outage schedule. This project was originally scheduled to execute in 2025 through 2027. The Company's current plans are to execute the project in 2026 through 2029 in order to minimize the impact on unit availability.

Q. Please discuss the 2024 capital projects that were not included in Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The disposition of these capital projects is presented below:

- Covert Heat Recovery Steam Generator ("HRSG") Expansion Joint Replacements ($1,284,244). There was no projected amount for 2024, however the work was required as a result of equipment (seal) failure. The seals for all three units failed, resulting in hot flue gas blowing out of the unit. This presented a safety issue, as there were areas around the units that a person could not safely approach due to excessive heat and exhaust gas inhalation. In addition, the site was also experiencing issues where the some of the instrumentation cables were failing due to the excessive heat melting their insulation. Finally, because of the seal failures, the insulation failed in the floor sections of the duct where these penetrations are located. To replace the expansion joints and not address the insulation would have resulted in a quick recurrence of the expansion joints failing. The work to remove liners and replace the insulation was more costly than the expansion joint work, but a necessary part of the overall replacement. Project closeout for this project will be completed in the bridge period as discussed later in this direct testimony;

- Covert LTSA Extra Work Unit 2 ($1,339,561). The projected amount for 2024 was $750,000 and the amount projected for 2025 was $12,576,300. The actual amount came in higher due to pulling some of the investment forward, thereby reducing the projected amount for the 16-month bridge period to $12,153,320. This project will be discussed in more detail later in this direct testimony;

- Jackson Units 1-6 Feedwater ("FW") Desuperheater Valve ($1,871,081). The scope of this project was to install FW control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously. The HRSG 1-6 superheat ("SH") Steam Desuperheater FW valves have had very short life spans since original construction. There were several issues that caused the valves to wear out quickly. The valves inherently cycled frequently open and closed due to the boiler running close to high pressure ("HP") Steam Outlet temperature setpoint at gas turbine baseload, without duct firing. This has been reduced recently by a study completed by engineering and GE to allow the HP Steam temperature to be increased from the original 750 degrees Fahrenheit up to 770 degrees Fahrenheit. This change did cause the valves to cycle open/close less frequently, but it did not result in a substantial improvement in valve life. The brunt of the wear is absorbed by the High Pressure Feedwater Autoblock valve, which when it begins to leak by, causes the SH Steam temperature to fall. The HP FW Control Valve wears out quickly as well. Typically, when this occurs the leak by accelerates quickly to the point which the manual HP FW isolation valve upstream must be closed when the unit is not duct firing to maintain adequate superheated steam temperature. The projected amount for 2024 was $828,100. However, this projected cost was not based upon a solicitation. Upon receiving proposals it was learned that the lowest bid amount was approximately $1 million higher than the projected cost. The project payback is still relatively short as the plant was experiencing approximately three failures annually at a cost greater than $1 million;

- Zeeland Site Spare Generator Step-Up ("GSU") (2,039,715). The scope of this project is to purchase a spare GSU. The projected spend was $589,607 for the bridge period and $2,340,637 for the test year. The project is described in more detail later in this direct testimony; and

- Zeeland Phase 2 599 and 699 345 kV breaker replacement ($1,855,883). The scope of this project is to replace the 599 and 699 circuit breakers with a type which does not exhibit the failure modes exhibited by the existing design. The existing breakers have a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland Substation, and/or equipment damage. The projected amount for 2024 was $319,559 and was originally scheduled for execution in 2023. However, it was pushed to 2024 for various reasons including the fact that the breaker delivery and GSU project delivery missed their 2023 installation targets.

The following four projects were all implemented to support the separation of Karn Units 1 and 2 from Karn Units 3 and 4. This unit separation work was presented in the Company's 2021 IRP and the Company's 2023 Electric Rate Case No. U-21389 but was not appropriately reflected in the Company's 2024 Electric Rate case, Case No. U-21585 as it was erroneously reflected as decommissioning/cost of removal. Each of these projects were required to operate Karn Units 3 and 4 independent of Karn Units 1 and 2 following their retirement on May 31, 2023.

- New Electrical System from Weadock Sub for Karn 3 and 4 ($1,523,648);
- Discharge Line Reroute for K 3 and 4 Sump Water ($1,905,159);
- New building to house new fire water system ($1,019,275); and
- New 46kV to 4160 transformer to re-power facilities ($3,065,403).

The projected spend for the bridge period for the following two projects was less than $1 million in the Company's original filing but the projected spend was updated to be greater than $1 million and presented in Staff Exhibit No. S-16.1 (RDB-2), page 1 of 2.

- Karn 3&4 Tank Farm Heating Line Replacement ($1,216,552); and
- Netmation (MHPSA Operating System & 4S) - Unit 1-3 ($5,046,654).

PROJECTED 16-MONTH BRIDGE PERIOD CAPITAL EXPENDITURES

Q. How does the projected 16-month bridge period capital expenditure of $275.408 million compare to the amount of capital requested by the Company in Case No. U-21585 for 2025?

A. The 16-month bridge period projected capital expenditure amount of $275.408 million compares favorably with the $724.728 million for the 14-month period beginning January 1, 2025 through February 28, 2026. While the difference is quite large, it is important to call out that the Company's initial request in Case No. U-21585 for the 14-month period beginning January 1, 2025 through February 28, 2026 included $373.076 million for three solar projects which the Company has since removed and moved to its Renewable Energy Plan Case No. U-21816 and also included $96.582 million for River Hydro investments. In addition, a portion of the projected BESS investment was moved out beyond the test year in Case No. U-21585 and, as a result, that investment had no material impact on the revenue requirement used to establish rates. A detailed discussion of the BESS projects is presented in Company witness Clark's direct testimony. A compilation of the 16-month bridge period projects which have projected capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, and an explanation of the project changes is described in more detail later in this direct testimony.

Q. How does the compilation of 16-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, compare with the test year capital projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9?

A. A comparison of the 16-month bridge period capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, with the test year projects reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, reveals that there are 12 projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, which were not reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9. In addition, there were 11 projects for the 12-month period ending February 30, 2026 that were reflected on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8. The River Hydro projects were not considered in this evaluation due to their removal.

Q. Please discuss the test year capital projects that were included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, due to the fact that the projected bridge period capital expenditure amounts are now less than $1 million or the project is not being pursued in the bridge period. The disposition of these capital projects is presented in the table below:

Site	Project	Disposition
Covert	Cooling Tower Gearboxes	project spend reduced in U-21585
Covert	Unit 1 - LTSA Capital - Extra work not included in contract	Project disallowed in U-21585
Covert	Office Space Consumers Energy Warehouse with Loading Dock	Project disallowed in U-21585
Karn 4	Karn 4 Replacement of Ductwork Insulation and Lagging	Project disallowed in U-21585
Zeeland	Generator Rewinds	Inspection determined work not required
Ludington	Ludington Intake Gate and Gate House Mechanical Replacement	$1.732 million in bridge period and test year
Ludington	Station Power Transformer Life Cycle Management	$1.407 million in bridge period and test year
BESS	Armstrong Battery Energy Storage System (IIJA Grant App)	Project COD delayed to beyond test year
Solar IRP	Solar - 2021 Bid Event (Muskegon Solar) (250 MW)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2022 Bid Event (Spring Creek)	Moved to the Renewable Energy Plan
Solar IRP	Solar - 2020 Bid Event (Washtenaw Solar) (150 MW)	Moved to the Renewable Energy Plan

Q. Please identify the 16-month bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, that are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8.

A. The bridge period capital projects that were not included on Case No. U-21585, Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, are presented in the table below:

Line No.	Site	Project Description
1	Covert	Load Commutated Inverter Static Frequency Converter
2	Jackson	Purchase of site spare GSU
3	Jackson	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement
4	Jackson	LTSA Capital - Extra work not included in contract
5	Zeeland	Unit 5 GSU Transformer
6	Karn 3	Combustion Air Heater Replacement
7	Karn 4	Combustion Air Heater Replacement
8	Karn 4	ID Fan Inlet Damper Replacements
9	Ludington	Replace Lower Penstock Expansion Joint
10	Ludington	Station Water Dschrg Isolation Valve
11	Admin	Wastwater Treatment System

The basis for these projects will be discussed in more detail later in this direct testimony.

Q. Is the projected capital expenditure amount of $275.408 million for the 16-month bridge period ending April 30, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (e), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (h), $70.614 million will fund BESS projects, $171.787 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $15.225 million will fund various projects at the LPS facility. With the exception of the BESS projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The BESS projects will be discussed in the direct testimony of Company witness Clark.

<u>PROJECTED TEST YEAR CAPITAL EXPENDITURES</u>

Q. Is the projected capital expenditure amount of $188.638 million for the test year ending April 30, 2027, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (f), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 84, column (j), $26.392 million will fund BESS projects, $137.913 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $13.282 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019.

Except for the BESS projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The BESS projects will be discussed in the direct testimony of Company witness Clark.

Campbell Units 1, 2, and 3

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and projected test year ending April 30, 2027 for Campbell Units 1, 2, and 3.

A. The Company does not plan to invest any capital in the Campbell units during the bridge period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1 and 8. As presented on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, and as discussed later in this direct testimony, the Company has projected modest amounts of major maintenance to ensure that these units were able to operate through their retirement date of May 31, 2025.

Covert Plant

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and projected test year ending April 30, 2027 for Covert.

A. The Company plans to invest a total of $67.545 million in the 16-month bridge period and $61.443 million in the test year at the Covert Plant. These capital investments will be facilitated by nine-day outages at Covert Units 1 through 3 in the spring and fall of 2025 as well as longer unit outages for major inspections. Covert Unit 1 has a 59-day outage scheduled to begin on September 1, 2025, Covert Unit 3 has a 59-day outage scheduled to begin on March 15, 2026, and Covert Unit 2 had a 59-day outage scheduled that began on March 1, 2025.

Q. Please explain the Company's projected capital investment for the 16-month bridge period ending April 30, 2026 for the Covert Plant.

A. The Company plans to invest a total of $67.545 million in the bridge period on the Covert Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 43, column (h).

Q. What is the basis for the projected $67.545 million capital investment in the 16-month projected bridge period?

A. The projected $67.545 million capital investment in the projected bridge period will fund numerous projects at the Covert Plant. Seven of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 1 through 7. The basis for these six projects is described below:

- Load Commutated Inverter ("LCI") Static Frequency Converter ("SFC") Replacements ($1,305,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Purchase of site spare GSU (1,500,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Netmation (Operating System & 4S) – Units 1 through 3 ($2,921,689). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Units 1 through 3 Emerson DCS Evergreen ($2,156,101). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert; and
- Covert Plant LTSA ($26,246,048). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;
- Covert Unit 2 LTSA extra work ($12,153,320). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in

the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, Selective Catalytic Reduction ("SCR") catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. The major inspection on Covert Unit 2 began on February 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope of work; and

- Covert Unit 3 LTSA extra work ($9,009,801). The LTSA extra work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler. This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert.

The following projects are less than $1 million, but are important to reliability:

- Covert Unit Cooling Tower Gearboxes ($675,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Gas Compressor Controls Replacement (Programmable Logic Controller ("PLC") replacement) ($144,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- HRSG Expansion joint replacement ($450,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Balance of Plant ("BOP") Valves – Covert Units 1 through 3 ($1,105,200 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;

- Gas turbine generator and steam turbine generator auto voltage regulator – Covert Units 1 and 3 ($750,000 each). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;

- Covert Units 1 through 3 MTX High Voltage Bushing – GSU ($1,379,700 total). These projects span the 16-month bridge period and the test year, and their basis is included in my discussion of the test year capital projects for Covert;

- Linear Variable Differential Transformers ("LVDT") Positioning Sensor – Unit 2 Fuel Control Valves ($715,500). The scope of this project is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement is to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the Pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism;

  The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- LVDT Positioning Sensor – Unit 1 Fuel Control Valves ($253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- LVDT Positioning Sensor – Unit 3 Fuel Control Valves ($253,500). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Small Site Capital ($380,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Covert Base Outage Capital ($774,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- 3A Circ Pump/Motor Replacement ($630,000). The Circulating Water Pump Replacement project is a critical initiative aimed at replacing the Unit 3A circulating water pump and motor, which have been in operation for over 20 years and have reached the end of their service life based on failure data compiled from the rest of the circulating water pumps on site. This replacement is necessary to maintain plant reliability and avoid potential unit derates;

- Covert – high energy piping surveillance ("HEPS")/ flow accelerated corrosion ("FAC")/ deaerator and its storage tank ("DAST") Inspections ($327,500). This project aims to bring the Covert site into compliance with existing corporate governance on G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs ensures the safe operation of the site and provides outage scheduling flexibility by transitioning from a 12-month operating certificate to 2-year and 3-year operating certificates. The project is essential to maintain the ability to implement 2-year and 3-year operating certificates. Failure to perform the required inspections would limit the unit to a 12-month operating certificate, necessitating a full inspection before the unit can be certified to operate;

- Units 1,2,3 North American Electric Reliability Corporation ("NERC") Relay Replacements and Test Switch Installation ($685,712). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Covert;

- Excitation Replacement ($263,833). The scope of this project is the replacement of the steam turbine exciters. The existing excitation equipment is obsolete, and the gas turbine exciters have already been replaced. A failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found with a typical lead time of 18-24 months; and

- Twenty-five additional projects at Covert totaling $3.043 million which support safety, security, and reliability, with each project representing $243,000 or less in capital expenditures. These projects include gas turbine wheel flame detectors, gas turbine evaporator media, plant fuel gas bypass system, ammonia fan replacements, actuator replacements, and unit 1 Power Distribution Center ("PDC") battery replacement.

Q. What is the basis for the projected $61.443million capital investment in the projected test year?

A. The projected $61.443 million capital investment in the projected test year will fund numerous projects at the Covert Plant. Six of these projects are greater than $1 million, and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 1 through 6. The basis for these projects is described below:

- LCI SFC Replacements ($2,610,000). The scope of this project is to replace the two SFCs which are both original to the plant's construction in 2001. The replacement of the SFC controls is required to mitigate the significant risk of failure due to obsolescence, ensure operational reliability, and align with manufacturer recommendations. The Covert Generating Station Static Frequency Converter Controls Replacement project is essential to address significant operational and reliability issues stemming from the obsolescence of the current SFC controls. The concept approval document for this project is attached as Exhibit A-46 (RTB-7);

- Purchase of site spare GSU transformer ($5,910,000). Covert Generating Station consists of three gas turbine powered plants and three steam turbine powered plants placed in a one-on-one combined cycle configuration. The units transmit their power to the grid via GSU transformers. Each gas turbine powered unit feeds the secondary winding of a three-winding transformer, while the associated steam powered unit feeds the tertiary winding of the transformer. The GSU is rated for 500 MVA with forced oil and forced air. If a GSU were to fail, then the associated turbines would not be able to transmit power and would not be able to generate market value for Consumers Energy and its customers. The lead time for a GSU is currently three-to-four years and spare units at other facilities typically do not exist, especially for this more unique design application;

  This project provides a spare GSU for Covert which 1) Greatly reduces unit downtime in the event of GSU issues or failure requiring removal and lowers the total financial losses in such events; 2) Allows for easier engineering design and planning to install a spare or replacement GSU ahead of any emergent installation needs; 3) Mitigates potential issues from installing GSUs not specifically designed for this location, system, or application and/or doing it multiple times in a short time period; 4) Would allow for Consumers Energy to enter lease agreements with other utilities who may be in need of a spare to recover some costs of the spare purchase over time; and 5) The oil analysis of Covert transformers revealed the presence of chemicals for corrosive sulfur. Mitigating actions are being taken, however, this failure mode puts these transformers at increased risk of failure. The concept approval document for this project is attached as Exhibit A-47 (RTB-8);

- Netmation (Operating System & 4S) ($8,843,713). The Covert gas generating station, operational since 2004, faces critical challenges with its outdated control systems. These challenges impact both operational efficiency and cybersecurity, necessitating an urgent upgrade to modern standards. The scope of this project is an extensive upgrade of the Covert Mitsubishi Turbine Control System to the latest version of Netmation, which includes the replacement of hardware, input/output ("I/O") modules, servers, workstations, network switches, and software to the latest architecture. The concept approval document for this project is attached as Exhibit A-48 (RTB-9);

- Covert Plant LTSA ($18,811,878). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an Effective Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. During the bridge period and test year, the Company will be conducting major inspections on all three generating units, and a portion of the work to be performed is not covered in the LTSA, rather it is covered in the LTSA extra work as described below;

- Covert Unit 1 LTSA extra work ($9,524,986). The LTSA extra work is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include, but are not limited to: (i) Steam turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection for Covert Unit 1 begins on September 1, 2026, and ends on October 30, 2026. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units; and

- Covert Unit 3 LTSA extra work ($4,093,234). The LTSA extra work is defined as the owner's obligations per the LTSA division of responsibility for work performed by the OEM. The Covert LTSA outlines a division of responsibility, with many items falling under the owner's responsibility to purchase or furnish to the OEM for completing the work scope designated by the LTSA. These items include, but are not limited to: (i) Required crane rentals to support rigging and moving various pieces and parts, (ii) Office and break trailer rentals for personnel onsite during the outage, (iii) Restroom and wash facilities for onsite personnel supporting the outage, (iv) Drinking water, (v) Trailer rentals for moving parts and pieces to designated laydown areas, (vi) Support structure assembly for the generator field when it is removed from the generator, (vii) Removal of the building wall for generator field removal, (viii) Scaffolding and insulation services, (ix) Generator electrical testing. These items are not covered by the LTSA but are necessary to support the LTSA work scope. All parts required for the generators and the steam turbine are not covered by the LTSA but are essential for executing the outage. Some of these parts are consumable, while others are deemed unusable per inspections performed during the outage. Any parts damaged during disassembly that are required to perform the LTSA scope of work would also be replaced. Examples include bolting, valve assemblies, gaskets, thrust shim plates, and steam turbine packing. The labor to install packing and the resulting steam path alignment activities are also not covered by the LTSA but are necessary to perform the work scope per the LTSA. Additionally, once the steam turbine, gas turbine, and generators are disassembled and inspected, historical outage experience and industry experience indicate that many items will need to be repaired that are not covered by the LTSA. These items include, but are not limited to: (i) Steam turbine rotor repairs, (ii) Steam turbine diaphragm repairs, (iii) All bearing repairs for the gas turbine, steam turbine, and generators, (iv) Hydrogen seal repairs, (v) Steam turbine shell repairs, (vi) Collector ring machining, and (vii) Compressor hook fit repairs. The major inspection on Covert Unit 3 begins on March 15, 2026, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with MEPPI does not cover this scope of work. Consumers Energy used the historical expenses for these items incurred by the previous owner of the plant and escalated the amounts for inflation. Additionally, current plant performance and previous outage reports were reviewed to predict as close as possible any additional work scope that would be required to restore the units to necessary reliability and performance standards while reducing any risk to the unit as much as practical. Consumers Energy also predicted that some repairs that were deferred by previous owners will have degraded to a point that repairs are now prudent. These were all combined to establish the Company's first outage scopes and budgets for the Covert units.

The following projects are less than $1 million, but are important to reliability:

- Gas Compressor Controls Replacement PLC replacement ($576,000). Gas Compressors (two in total) operate using a local control network consisting of a human machine interface ("HMI") (Panel View 1000) and Allen Bradley PLC five controllers. This equipment has reached end of life and replacements are no longer available. The Covert site currently has one failed board in service. This project would utilize existing panels and replace the equipment with an Allen Bradley ControlLogix solution and PanelView Plus 7;

- HRSG Joint replacement ($360,000). The scope of this project is to replace the vertical round expansion joint between the combustion turbine and the building and the HRSG. The Covert Generating Station HRSG expansion joint replacement project addresses the critical issue of aging expansion joints on all three units. These joints have a design life of 6-8 years and are typically replaced during turbine major outages. However, the existing expansion joints will be at least four years beyond their design life if replacement is delayed until the next major outage. This significantly increases the probability of failure, which could start as a small tear detectable by thermography but could also result in a large rip. Such failures would allow exhaust gases to bypass the stack and environmental monitoring equipment, releasing high-temperature gas inside the building, posing a personnel hazard and significantly impacting overall heat rate efficiency. A failure of the expansion joint could force the unit offline for 30 days until it is replaced, potentially resulting in a month of downtime if the failure is severe;

- Plant Replace Sulfuric Sodium Hypo and Building ($600,000). The project involves replacing the existing sulfuric acid and sodium hypochlorite dosing systems and the building housing these systems at Covert. The current sodium hypochlorite system, in operation since 2004, has experienced over 60 documented failures, leading to chemical releases and hazardous cleanup situations. The system has surpassed its expected life cycle, posing increased risks of employee exposure, injury, and environmental contamination. The primary objective is to replace the aging sodium hypochlorite and sulfuric acid dosing systems and their housing structure to mitigate the risks associated with chemical spills and exposure to hazardous vapors. By separating the dosing systems, the potential for a combined spill creating chlorine gas is significantly reduced;

- Unit 1 Cooling Tower Gearboxes ($675,000). The Covert Generating Station Cooling Tower Fan Gearbox Replacement Project addresses critical operational issues stemming from the end-of-life status of gearboxes after over 20 years of service. These gearboxes are essential for cooling tower fan operations, affecting the station's overall efficiency and reliability. The scope of this project is to replace the existing cooling tower gearboxes with gearboxes from the same manufacturer, an alternative that avoids additional modifications. Covert operates three 6-cell cooling towers corresponding to each of its units. These cooling towers play a crucial role in the station's operational efficiency by facilitating the removal of residual heat from circulating water. This process is essential after the water has been utilized for condensing steam produced by the steam turbines. Operational challenges with the gearboxes include increased gearbox failures, inadequate heat removal due to malfunctioning cooling tower fans, and obsolete motor starters; and

- Covert Units 1 through 3 Emerson DCS Evergreen ($967,800). The scope of this project is to upgrade the DCS to the latest version in order to enhance security, gain compliance with enterprise standards, and achieve technological advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation DCS. The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the current version. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

  The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under NERC Critical Infrastructure Protection requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

  The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing the end of support and requires updating to allow support of the latest Ovation versions.

The BOP control is achieved with the Ovation DCS. Its architecture is comprised of controller and operator “drops” (processors and PCs) that provide the control of the equipment with I/O modules. Some of these I/O modules are in the same electrical cabinets that contain the “controller drops” (processors). Other I/O is in “remote” electrical cabinets, away from the “controller drops.” The existing plant control is comprised of many remote I/O cabinets throughout the site. The communication modules to these cabinets have experienced failures in the past that can trip the generating units offline. Power supplies in the Ovation cabinets have reached the end of their recommended life and need to be replaced. The architecture and components need to be upgraded and replaced with the latest Ovation design.

The main controller drop that operates a large part of the BOP equipment has had equipment and data link controls added to it over the years. It controls equipment for all three (3) generating units. The controller drop needs to have part of its I/O and logic split off to new controller drops. The partitioning of I/O to other drops should allow the upgrade and maintenance procedures to occur and reduce the need of a site outage to perform these activities. Risk to unit trips should be reduced to individual generating units instead of all units on the site. The concept approval document for this project is attached as Exhibit A-49 (RTB-10);

- Flame Detectors for Gas Turbine Wheel temperature Digital replacement ($273,000 total). The scope of this project is to replace the existing mechanical flame detection system with a digital flame detection system. The existing system is obsolete and has reliability issues that a new digital system would resolve;

- Balance Of Plant Valves – Unit 1 ($450,000). The scope of this project is the repair and/or replacement of balance of plant valves. Project is to overhaul the U1 HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt in 2017 and PV110 has never been overhauled. These valves are used for startup, shutdown and unit trips to bypass steam to the condenser and experience extreme service conditions that should be considered for overhaul every 7 to 10 years. These projects should align with major outages to allow for ample time to disassemble, inspect and repair. Overhauling the valves results in reliable dependable service as these valves are critical to starting up and shutting down the unit. They must also operate during trip conditions to prevent an overpressure event and potential damage to other components;

- Balance Of Plant Valves – Unit 3 ($450,000). The Scope of this project is to overhaul the HRS-PV105 and LPS-PV110 steam bypass valves. PV105 was last rebuilt in spring 2019 and PV110 has never been overhauled. These valves are used for startup, shutdown, and unit trips to bypass steam to the condenser and experience extreme service conditions that should be considered for overhaul every 7 to 10 years;

- Gas turbine generator and steam turbine generator auto voltage regulator – Covert Units 1 and 3 ($600,000 each). The current MEC5000 digital automatic voltage regulators ("D-AVR"), which are over 20 years old, pose a substantial risk of failure. Any failure in these D-AVRs renders both the gas turbine generator ("GTG") and steam turbine generator ("STG") on the affected unit unavailable, leading to extended outages and significant financial impacts. The OEM has indicated a lead time of 18-24 months for new D-AVRs;

- AVR parts, further exacerbating the potential downtime. The Covert Generating Station, operational since 2004, faces significant challenges with its aging MEC5000 D-AVRs. These regulators, critical for controlling the generators' response to load demand, are obsolete and no longer supported by the OEM, Mitsubishi Electric (MELCO). This project proposes the replacement of the MEC5000 D-AVRs with the advanced MEC700 AVR System for Units 1 and 3, to mitigate obsolescence risks and ensure reliable operation;

- Covert Units 1 through 3 MTX High Voltage Bushing – GSU ($1,015,200 total). The 1MTX GSU transformer has over 20 years of service life and its high voltage (HV) bushings are showing insulation deterioration that was exposed through power factor testing prior to Consumers Energy ownership. The GSU also is overdue for internal inspection with attention to mitigate risk for its pacified oil that is still exhibiting corrosive potential properties. To engineering's knowledge this unit has never been fully drained and undergone internal inspection prior to or after the oil pacification work was performed earlier in its life. The unit has oil that was pacified for corrosive Sulfur, however Doble and other industry experts strongly recommend the pacified oil be replaced as soon as possible since Sulfur corrosion leading to failure is still probable due to remaining residuals in the pacified oil. It was noted in the root cause analysis for the Zeeland Unit 2C GSU that corrosive sulfur had an impact on its failure by reacting with conductors to create localized overheating. The HV bushing replacement mitigates any potential for failure in service. The bushing insulation properties continue to degrade over time as indicated through recent power factor testing before Consumers Energy took over the site. HV bushings power factor test results give the impression the bushings of 1MTX should have 5-10 years of life remaining before failure is realized, however neither the rate of deterioration nor exact failure timeframe is predictable. Due to lead times, planning for replacement is a more cost-effective solution for customers than verifying they are failing during a future outage and forcing extension until they can be replaced. A major outage for Covert will be required to have enough time to execute the work, which will require at least 12 days based on similar scope at ZGS. Internal inspection is part of the preventative maintenance plan and helps the Company determine the health of the transformer, plan future outages as needed, and prevent forced outages, thereby reducing potential ROR;

- Units 1, 2, and 3 NERC Relay Replacements and Test Switch Installation ($700,712). This project is needed to preclude unnecessary risk associated with possible relay failures as the existing relays are at the end of life. Running to failure is not an option for relay protection equipment because of the extremely high costs of equipment failures that could result if relay protection schemes failed to operate as designed. In late 2024, Covert experienced its first indication of a relay failure on Unit 3 and is operating at this time with no redundant protection in this specific zone. The failed relay is original to the plant and more relay failures can be expected as time goes on.

A failure of the remaining protection scheme in this zone would result in a forced outage, and it is expected that the turn-around time for sourcing, testing, installation, and commissioning of relays like this would take approximately two weeks if all went well. Relay manufacturers and Consumers Energy's High Voltage Distribution group use 25 years as recommended service life for these types of devices.

Each unit has multiple digital protection relays to ensure protection to the generation equipment (Generators/Exciters/Transformers) from local faults as well as to ensure protection from grid disturbances that could damage our valuable equipment. The original relays at Covert were not installed with the necessary test and cutout switches, which requires that the unit be offline for maintenance and replacement and creates greater potential for human performance errors that can jeopardize system reliability;

- LVDT Positioning Sensor – Units 1 and 3 Fuel Control Valves ($507,000 each). The scope of these projects is to replace the Yokogawa 5516 mechanical type position sensors with LVDTs. The replacement to include the following devices, Main "A" pressure control fuel valve sensor, Main "B" pressure control fuel valve sensor, Main flow control fuel valve sensor, Pilot pressure control fuel valve sensor, and the pilot flow control fuel valve sensor and compressor bypass actuator. The benefits of this project include reduced maintenance, improved accuracy, and higher long-term reliability due to the removal of the mechanical linkages and converting to a non-contact mechanism.

  The Covert Mitsubishi Power Gas turbines are equipped with Yokogawa 5516 mechanical linkage type position sensors. The Yokogawa position sensors are used to detect the position of the fuel control valves, bypass valve actuators, and the Inlet Guide Vanes. These Valves and their position are critical as they control turbine output which allows more load on the generator and meets load demand. The Yokogawa 5516 position sensors are obsolete, and Yokogawa has announced that the 5516 position sensors are no longer manufactured as of March 31, 2015, are no longer supported, and parts are no longer available. Mitsubishi Power recommends eliminating the Yokogawa mechanical linkage position sensors;

- Covert - HEPS/FAC/DAST Inspections ($347,500). This project aims to bring the Covert site into compliance with existing corporate governance on

G-A-313, G-A-314, and G-A-315 programs. Compliance with these programs ensures the safe operation of the site and provides outage scheduling flexibility by transitioning from a 12-month operating certificate to 2-year and 3-year operating certificates. The project is essential to maintain the ability to implement 2-year and 3-year operating certificates. Failure to perform the required inspections would limit the unit to a 12-month operating certificate, necessitating a full inspection before the unit can be certified to operate;

- Small Site Capital ($285,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Covert during the projected bridge period;
- Covert Base Outage Capital ($360,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages; and
- Eighteen additional projects at Covert totaling $2.185 million which support safety, security, and reliability, with each project representing $210,000 or less in capital expenditures. These projects include Plant Fuel Gas Bypass System, SP transformers, Gas Turbine - Unit 1 and 3 Evaporator Media, gas and steam turbine excitation transformers, hydrogen new bulk system, Unit 2 LTSA extra work, and air compressors.

Karn Units 1 and 2

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for Karn Units 1 and 2.

A. The Company does not plan to make any capital investments on Karn Units 1 and 2 in the 16-month projected bridge period ending April 30, 2026 or the projected test year ending April 30, 2027, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 15, columns (h) and (j), respectively, due to their retirement on May 31, 2023.

<u>Karn Units 3 and 4</u>

Q. Please explain the Company's projected capital investment for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027, for Karn Units 3 and 4.

A. The Company plans to invest $12.478 million in the projected bridge period and $8.304 million in the projected test year, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 22, columns (h) and (j), respectively.

Q. What is the basis for the projected $12.478million capital investment in the 16-month projected bridge period?

A. The projected $12.478 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at Karn Units 3 and 4. There are four projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 17 through 20.

The basis for these projects is described below:

- Karn Unit 3 Combustion Air Heater replacement ($2,700,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Combustion Air Heater replacement ($3,000,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Units 3 and 4 Ductwork Expansion Joint Replacement – Induction Draft ("ID") Fans to Stack ($1,800,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4;
- Karn Unit 4 Induced Draft ("ID") Fan Inlet Damper Replacements ($2,700,000). The scope of this project is to replace the ID fan inlet dampers. The Karn Unit 4 ID fan inlet dampers play a crucial role in regulating the fan load and maintaining a negative draft in the boiler, which is essential for safe and reliable operation. Over the last five years, the dampers have experienced multiple failures, leading to forced outages and significant de-rates, indicating

the urgent need for replacement. The Karn Unit 4 ID Fan Inlet Damper Replacement project is critical to ensuring reliable and efficient operation of the unit. The current ID fan inlet dampers, which are essential for controlling the boiler draft, are aging and have caused multiple forced outages and significant capacity de-rates over the past five years. These failures have resulted in high operational costs, inefficiencies, and risks of continued disruptions during peak operational periods. Replacing the dampers is a proactive investment that will eliminate these risks and provide long-term operational stability. The concept approval document for this project is attached as Exhibit A-50 (RTB-11);

The following projects are less than $1 million, but are important to reliability:

- Karn Unit 4 Vibration System Replacement ($774,900). This project replaces all Rockwell Automation XM Monitoring vibration modules that are currently located in electrical junction boxes located around the Karn 4 turbine. The existing junction boxes will be used as termination boxes and new cables run to a central point on the Karn 4 turbine deck (turbine office at SW corner). A new Ovation DCS cabinet with R-Line Machine Health Monitor "MHM" vibration modules is to be installed in the turbine office area. This cabinet will contain (6) 8-point MHM modules (total of 48 inputs) and two output modules. Ovation OCC-100 redundant controllers will be used to integrate with the existing Ovation DCS. The enclosure door will contain active buffered output splitters to allow connection to the Consumers Energy turbine group's Turbo-Balancer. Redundant output modules will be utilized for proper hardwired trip signals;

  The existing Rockwell computer located in the Karn 3&4 DCS room will be removed and all interfaces for the new system will be through the integrated Ovation DCS operator and engineering drops. An Emerson Asset Management System "AMS" Machine Works Server and Waveform Recorder Server provides advanced condition monitoring and full vibration spectrum data for historical playback of trip events and diagnostics of turbine issues. The sensors and cables will also be replaced;

- BOP Capital tooling/valves/instrumentation ($380,000). This project spans the 16-month bridge period and the test year, and its basis is included in my discussion of the test year capital projects for Karn Units 3 and 4; and

- Ten additional projects at Karn Units 3 and 4 totaling $1.123 million which support safety, security, and reliability, with each project representing $261,000 or less in capital expenditures. These projects include rewind of the Karn Unit 4 house service air compressor motor, replacement of the processors for the Karn Units 3 and 4 main boiler feed pump relay control conversion to DCS, Karn sync wire replacement, Karn Units 3 and 4 ID and forced draft ("FD") fan vibration systems, Karn Units 3 and 4 FD fan platforms, and replacement of house service water ("HSW") piping on Karn Units 3 and 4.

Q. What is the basis for the projected $8.664 million capital investment in the projected test year?

A. The projected $8.304 million capital investment in the projected test year will fund twelve projects. Three of these projects are greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 15-17. The basis for these projects is described below:

- Karn Units 3 & 4 Combustion Air Heater replacement ($1,800,001 for Unit 3, $2,250,000 for Unit 4). The scope of these projects is to replace the combustion air heaters. The D.E. Karn Generating Station, which utilizes natural gas and oil, employs steam-to-air heat exchangers known as combustion air heaters to preheat the ambient air entering the boiler. This preheating process is essential for optimizing combustion efficiency. Specifically, Karn Units 3 and 4 rely heavily on consistent air intake temperature to fine-tune the combustion air-fuel mixture, crucial for maintaining emissions within acceptable opacity limits and ensuring efficient heat rates as they do not have any other means of controlling the output of particulate matter. The projected benefits include enhanced reliability, improved efficiency, and ensured regulatory compliance, avoiding projected capacity revenue losses of over $23 million. This proactive approach addresses the root cause of failures, providing a long-term solution for operational efficiency and cost savings. The concept approval document for these projects is attached as Exhibit A-51 (RTB-12); and

- Ductwork Expansion Joint Replacement –ID Fans to Stack ($1,800,000). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance.

The following projects are less than $1 million, but are important to reliability:

- Karn Unit 3 Residual Oil Heater Overhaul ($495,000). The scope of this project is to install new tube bundles. The existing tube bundles have many leaks, and the heaters are no longer functioning and are cut out of the system;

- Karn Unit 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($750,000). The scope of this project is to replace the lagging and insulation on all the ductwork from the building out to the stack. The existing lagging and insulation needs to be removed, the underlying steel fixed as necessary, and new insulation and lagging installed. The steel structure that the ductwork lagging is attached to is severely corroded. This has allowed multiple random failures of the lagging, resulting in a safety concern due to pieces of lagging falling to the ground or becoming airborne during wind events;

- Karn Units 3 and 4 ID and forced draft ("FD") Fan Vibration Systems ($266,400 per unit). The existing ID Fan Vibration System was originally used for monitoring and alarming purposes only and was not designed to be a vibration protection system. When a catastrophic ID Fan failure occurred in 2016, the vibration alarms were changed from only alarms to also tripping the fan. With this change, the Company had several false positive trips from the system resulting in unit trips. The original system currently provides an analog signal into the DCS where the values are displayed and alarm messages are generated, and the DCS stops the ID fan if the analog value goes above the trip limit.

  This project replaces the current system with Ovation Machinery Health Monitor R-Line modules located in an Ovation remote I/O cabinet near the ID Fans. The remote drop will utilize Ovation Remote Node Interface for connection into the existing Ovation DCS. This will also provide vibration monitoring and protection for the FD Fans. A total of 24 speed and vibration sensors are included for the two ID and two FD fans and motors (3A and 3B ID Fan and motor, and 3A and 3B FD Fan and motor). Active buffered output splitters at the enclosure are also included to allow for supported vibration monitoring with a 2140 portable monitor and use of the turbo balancer for fan balancing. All waterfall and waveform plots of the vibrations are available for display on the Ovation system. Full API-670 protection capability is provided with seamless integration to the existing Emerson Ovation DCS;

- Capital tooling/valves/instrumentation ($285,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year; and

  Three additional projects at Karn Units 3 and 4 totaling $0.392 million which support reliability, with each project representing $180,001 or less in capital expenditures. These projects include the Karn Units 3 and 4 FD fan outlet dampers, HSW piping replacement, and tank farm PLC/DCS replacement.

<u>Zeeland Plant</u>

Q. Please explain the Company's projected investment for the 16-month projected bridge period ending April 30, 2026 and projected test year ending April 30, 2027 for the Zeeland Plant.

A. The Company plans to invest $67.275 million in the 16-month projected bridge period and $40.023 million in the projected test year at the Zeeland Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 29, columns (h) and (j), respectively. These capital expenditures will be facilitated, in part, by 35-day outages on Zeeland Units 1 and 2 in the spring 2025 as well as short outages of about 15 days in the spring and fall of the 16-month projected bridge period and the projected test year. The Company has an LTSA with GE that covers many reliability investments at the Zeeland Plant.

Q. What is the basis for the projected $67.275 million capital investment in the 16-month projected bridge period?

A. The projected $67.275 million capital investment will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are five projects which are greater than $1 million, and these projects are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 12 through 16. The basis for these projects is described below:

- LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($43,697,329). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Phase II Turbine Replacements ($10,174,501). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;
- Zeeland Purchase of Site Spare GSU transformer ($2,340,637). This project spans the projected bridge period and the projected test year, and its basis is

included in my discussion of projected test year capital projects for the Zeeland Plant;

- Unit 5 GSU Transformer Rewind ($2,430,000). The scope of this project was to remove the failed Zeeland Unit 5 GSU transformer, movement and installation of the spare GSU transformer, and send out the failed Zeeland Unit 5 GSU transformer for overhaul which included milestone payments for the overhaul. In addition, the scope reflected the monthly lease of a spare transformer to provide continued operation of the unit for customers. Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned to service on January 23, 2023 upon installation of the leased transformer which was moved from Zeeland Unit 1. The project cost for 2025 reflects the return of the leased transformer as well as the remaining lease payment; and

- Zeeland Plant LTSA supplementals not included in contract ($4,703,401). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- GasTurbine inlet filters replacement ($360,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;

- Small Site Capital ($380,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant;

- Asea Brown Boveri (“ABB”) DCS Evergreen ($648,680). This project upgrades the ZGS BOP DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2020. This Evergreen will only replace the existing ABB Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade;

- ZGS – General Electric DCS Evergreen ($839,665). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson PWCS application.

The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches;

- Min Flow Bypass Valves Replacement ($450,000). The scope of this project is to replace four minimum flow bypass valves. These valves are original to the plant and recent inspections have indicated nearly all the valve internals need replacement, which is also evident during operation with excessive leak-by. It was determined the most sensible approach is replacement due to the extent and cost of recommended repairs, and new valves will ensure continued reliability for 10+ years in the control of minimum flow for the FW pump system;

- Cooling Tower Transformer Replacement ($225,000). The scope of this project is the replacement of the cooling tower transformer. Recent electrical testing indicated the transformer is failing. The Company determined that the most prudent option was replacement as compared to major repairs on a small transformer. Without this transformer, the cooling tower fans would not be operable, resulting in the Zeeland Phase 2 Units being shut down;

- Zeeland Plant Base Outage Capital ($381,900). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Zeeland Plant; and

- Seven additional projects at the Zeeland Plant totaling $0.644 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $180,000 or less in expenditures. These projects include Phase II 2A and 2B battery monitoring system, GT1B excitation transformer failing components, and peaking plant Generation Peaker.

Q. What is the basis for the projected $40.023 million capital investment in the projected test year?

A. The projected $40.023 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects at the Zeeland Plant. There are four projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 11-14. The basis for these projects is described below:

- Zeeland Site Spare GSU Transformer ($4,481,207). The scope of this project is the procurement of a spare GSU transformer for the Zeeland site. The Zeeland Plant consists of four gas turbine powered plants and one steam turbine powered plant. The units transmit their power to the grid via GSU transformers. If a GSU were to fail, then the associated turbine would not be able to transmit power and would not be able to generate energy and capacity market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently three to four years and spare units at other facilities are not viable replacements due to compatibility and installation challenges. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future;

- Phase II GT Advanced gas path replacement and axial fuel staging ($13,923,002). Zeeland Generating Station is a gas-powered combustion turbine plant consisting of four gas turbines and one steam turbine. These turbines are covered by a LTSA with General Electric to provide overhauls and upkeep on the units to periodically restore them to like-new condition. Periodically, the units are shut down for a major outage that is performed by General Electric. Part of the major work executed during such outages is replacement of the "hot", or combustion, parts as they degrade over their 32,000-hour design life. During these outages is the ideal time to incorporate major work that will improve the performance and/or reliability of the unit. The two gas turbines at Zeeland Phase 2 have Major Inspection outages in 2028. This project is to implement upgraded replacement parts in both phase 2 gas turbines. One such performance improvement (while maintaining the same reliability) is called an Advanced Gas Path ("AGP"). The AGP package provides significant output and efficiency (heat rate) improvements by replacing the turbine and combustion parts with higher performing and more technologically advanced parts. An additional improvement (while maintaining the same reliability) is called Axial Fuel Staging ("AFS"). The AFS package enables significant output turndown capability by replacing and adding combustion hardware with more technologically advanced parts that enable lower load operation while maintaining emissions compliance. This technology is potentially key to the Zeeland Phase 2 plant's ability to be flexible in supporting Consumers Energy's new energy portfolio, where a dramatic increase in renewable energy will demand greater flexibility from the rest of the generating assets in the portfolio. A more detailed analysis of this project is presented in Exhibit A-44 (RTB-5;

- Zeeland Plant LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($8,331,428). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services (OEM on-site/off-ite technical support, engineering, and labor). Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected premature failures of the equipment. Normal maintenance will ensure the Company continues reliable operation of the units.

The Phase I Gas Turbine Advanced gas path replacement and axial fuel staging project is being implemented in the Company's spring Phase 1 outage beginning on April 21, 2025. A more detailed analysis of this project is presented in Exhibit A-44 (RTB-5): Zeeland Phase 1 Gas Turbine upgrades;

- Phase II Turbine Replacements ($10,174,501). The scope of this project replaces the existing rotor with a new rotor, giving another 144,000 hours of operation which would enable operation until the next rotor replacement out to approximately the year 2045. Also included in this scope are new compressor stator vanes due to the compressor being 20 years old; the best way to restore the compressor to like-new condition is to replace the stationaries when the blades will already be replaced. Lastly, the exhaust frame will be upgraded to a robust exhaust frame due to reliability issues over the years, and the rotor replacement being an appropriate time to replace the exhaust frame.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Zeeland Plant LTSA supplementals not included in contract ($810,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Small Site Capital ($285,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Zeeland during the projected test year;

- Zeeland Plant Base Outage Capital ($382,500). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages at Zeeland;

- Combined Cycle Units 3 and 4 Air Filter Replacement ($648,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines; and

- Ten additional projects at the Zeeland Plant totaling $0.987 million support reliability and operations, with each project representing $240,000 or less in expenditures. These projects include Unit 1 and 2 battery monitoring system, 177, 277, 500 345kV breaker replacement, Phase 2 feed pump hydraulic coupling replacement, and Phase 1 Bentley Nevada vibration monitoring unit replacement.

Jackson Plant

Q. Please explain the Company's projected investment for the 16-month bridge period ending April 30, 2026 and test year ending April 30, 2027 for the Jackson Plant.

A. The Company plans to invest $24.489 million in the 16-month projected bridge period and $28.143 million in the projected test year at the Jackson Plant, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 36, columns (h) and (j), respectively. This will be facilitated by short outages in the spring and fall of 2025 and 2026. The Company has an LTSA with General Electric to cover many reliability issues at the Jackson Plant.

Q. What is the basis for the projected $24.489 million capital investment in the 16-month projected bridge period?

A. The projected $24.489 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 8-11. The basis for these projects is described below:

- Jackson Plant LTSA ($16,200,153). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Plant LTSA Extra Work ($2,115,001). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- GSU Transformer Site Spare ($1,333,333). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and

- LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement ($1,336,072). During the bi-annual borescope inspection in April 2024 for the LM6000 gas turbines at Jackson Generating Station, damage was identified at the High-Pressure Turbine ("HPT") Stage 2 Nozzle ("S2N") Impingement Ring of Engine Serial Number ("ESN") 191-306. The gas turbine with ESN 191-306 was placed in an 'on watch' period per OEM guidance that results in a 250 running hour inspection frequency to determine if the damage progresses. There is potential for the inspection frequency period to increase based on multiple inspections. Ultimately the S2N assembly of the gas turbine that is damaged needs to be replaced to restore the gas turbine to a serviceable condition.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- JLM1-6 Variable Inlet Guide Vane ("VIGV") Project ($646,911). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Jackson Generating Station General Electric DCS Replacement ($720,000). This project replaces the GE DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. (Standard practice is to replace virtualized system hardware every eight years to reduce costs.) The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. Vendor life cycle for DCS versions is generally a five-year cycle. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems (O/S) are on a limited life basis, and they reach the end of "extended support" and no longer get security patches. Corporate policies require all systems to be patched regularly along with Anti-Virus updates;

- LM6000 ESN 191-345 HP Turbine S1 Blade Replacement ($763,781). There are three LM6000 gas turbines ("GTs") at JGS that are currently experiencing burn through on their HPT Stage 1 Blades ("S1B"). Burn through represents the loss of a protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs that are experiencing this condition are indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual borescope inspections ("BSI") of all the JGS LM6000 GTs that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1Bs, and returned to JGS. The set of HPT S1Bs pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1Bs pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1Bs pulled from the third GT will be overhauled and returned to JGS to be used for future needs;

- Small Site Capital ($380,000). This project spans the projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant;

- Base Outage Capital ($270,000). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and

- Nine additional projects at the Jackson Plant totaling $0.724 million, with each individual project representing $225,000 or less in expenditures. These projects include Major Motor and Pump Replacements, Outdoor and roadway LED lighting replacement, Engine 191-306 Overhaul, Unit 7 Gas turbine rotor replacement, and LM6000 Beckwith Relay Replacement.

Q. What is the basis for the projected $28.143 million capital investment in the projected test year?

A. The projected $28.143 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 7-10. The basis for these projects are described below:

- Jackson Plant LTSA ($12,810,121). This is the capital portion for negotiated services that cover the planned normal maintenance of each unit based on its equivalent operating factor fired hours. The planned maintenance includes the following support services: OEM on-site/off-site technical support, engineering, and labor. Typical activities include borescope inspections, capital repairs, unit tuning, addressing service bulletin requirements, and on-site inspections. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Engine 191-306 Overhaul ($6,130,000). The project involves the provision of a nozzle assembly from General Electric. General Electric will also provide three field service representatives to remove the gas turbine from its package, replace the HP Turbine Rotor assembly, reassemble the gas turbine, install it back in the package, perform alignment, and provide startup support. The work will take place at the Jackson facility.

  During the bi-annual borescope inspection in April 2024 for the LM6000 gas turbines at Jackson Generating Station, damage was identified at the HPT S2N Impingement Ring of ESN 191-306. The gas turbine with ESN 191-306 was placed in an 'on watch' period per OEM guidance, resulting in a 250 running-hour inspection frequency to monitor the damage progression. Ultimately, the S2N assembly of the gas turbine needs to be replaced to restore the gas turbine to a serviceable condition;

- Unit 7 gas turbine rotor replacement ($1,663,577). The scope of this project is to replace the Unit 7 Gas Turbine Rotor as it is essential to prevent high-probability failures, ensure continued operation, and avoid significant downtime. This investment will provide long-term reliability and efficiency for the plant's operations, ensuring optimal performance of the gas turbine. The Jackson Generating Station Unit 7 Gas Turbine Rotor Replacement project is a critical initiative aimed at ensuring the continued operation and efficiency of the GE 7EA gas turbine. The rotor for this turbine has a life limit of either 5,000 starts or 250,000 running hours. A new rotor will take approximately two years to be delivered after the order; and

- GSU Transformer Site Spare ($2,333,334). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure in delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three-to-four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell, Karn, Lake winds, and Crosswinds do not have the correct voltage (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to function at Jackson so they cannot be considered for use as spares. The concept approval for this project is presented in Exhibit A-45 (RTB-6).

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- JLM1-6 VIGV Project ($960,102). This project will install new VIGV systems on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC engine has a partial installation already, and the project will complete the VIGV system for this engine. For LM6000PC SPRINT gas turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel efficiency improvement at part power. The average fuel efficiency improvement at 70% of maximum power is greater than 2%. The VIGV also helps minimize variable bypass valve ("VBV") flow and pressure levels, thereby reducing associated flow noise. The VIGV system improves performance for both simple cycle and heat-recovery cycles when operating at less than full load;

- Jackson Plant LTSA Supplemental Work ($315,000). The LTSA supplemental work is defined as the work that is not covered under normal planned maintenance in the LTSA. Based on historical outage experience there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items that need to be addressed are labor and material to replace the following: blading, combustion cans, ignitors, vanes/bushings, and any components on the compressor end as the compressor is not covered under the LTSA;

- Base Outage Capital ($270,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- 735 Breaker relay replacement ($384,300). One of the General Electric Multilin 735 relays that provides overcurrent protection to a large motor failed in service. This model of relay is no longer available. There are five of these relays at the Jackson plant. When another one fails, the motor will be forced out of service for a long duration while relays of a different manufacturer are installed. System protection recommends install of a SEL-551C and a BE1-851 as replacement;

- Steam turbine 9 blade replacement ($260,837). Impact damage was identified during the last major inspection of the unit in 2018. The first stage nozzle of the Jackson Generating Station had a design flaw failure where the peened caulking strips that hold the nozzle in its axial position liberated themselves from their original positions in the caulk/peen groove because of the expansion and contraction in the area. The liberation of these pieces caused impact damage to downstream components, most notably the rotor's blading. General Electric recommended at that time that repairs be made during the next major inspection. Blade replacement is needed for stages 1, 2, and 12 . Other stages' blading may require similar repairs. The rotor needs machining at radius leading to the stage 1 buckets due to imperfections from previous impact damage. Stage 10 blade covers need to be removed and replace with "Foxhole" type covers due to impact damage and erosion. The likelihood of the issues noted above achieving further degradation is high. The severity of consequence of leaving the above-mentioned damage as-is is high. The overall risk assessment is high (> 50%). For the longevity of the unit these items need to be addressed during the upcoming, routine overhaul;

- LM6000 ESN 191-307 HP Turbine S1 Blade Replacement ($782,866). There are three LM6000 GTs at JGS that are currently experiencing burn through on their HPT S1B. Burn through represents the loss of a protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GT's that are experiencing this condition are indicated by their ESN, ESN 191-339, ESN 191-345, and ESN 191-307. There are bi-annual BSI of all the JGS LM6000 GT's that monitor the GT condition. The BSI is the time where the HPT S1B condition is determined to be serviceable or unserviceable.

  The three GTs of concern at this time are in a similar state of condition, but the timing and the sequence of an unserviceable condition for each will be based on the BSI. In general, the first GT in sequence that is labeled unserviceable will be pulled from service, sent for repair with a new set of HPT S1B's, and returned to JGS. The set of HPT S1B's pulled from the first GT will be overhauled and made available for the second GT that becomes unserviceable, and the set of HPT S1B's pulled from the second GT will be overhauled and made available for the third GT that becomes unserviceable. The set of HPT S1B's pulled from the third GT will be overhauled and returned to JGS to be used for future needs;

- LM6000 HP Turbine S1 Blade Overhaul ($817,859). There are three of six LM6000 GT at JGS that are experiencing deterioration of their HPT S1B from normal operation. The HPT S1Bs are experiencing burn through which is described as the loss of the protective thermal barrier coating on the blades and the beginning of wear into the blade surface and base metal. Once any individual blade of the HPT S1B set meets an unserviceable condition per the OEM specifications, the gas turbine will not be allowed to operate. The three LM6000 GTs of concern will go through a sequence of replacing the HPT S1B, once the third GT is complete there will be a set of HPT S1B that will need to be overhauled for availability to the next LM6000 GT that requires the same blade set. This project is to capture the cost of the blade overhaul following the third LM6000 GT HPT S1B replacement;

- Small Site Capital ($285,000). This project supports capital expenditures for the replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Zeeland during the projected test year; and

- Ten additional projects at Jackson Plant totaling $1.130 million, with each individual project representing $225,000 or less in expenditures. These projects include 269 Breaker relay replacement, Site Control Room heating, ventilation, and cooling ("HVAC") Replacement, 4160V Electrical Room HVAC Replacement, steam turbine 8&9 turning gear platforms, and Major Motor and Pump Replacement.

<u>HYDRO UNITS</u>

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the Hydro Units.

A. The Company is not presenting any capital investments during the 16-month bridge period or projected test year in the Hydro Units, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 50, columns (h) and (j), respectively. The Company is requesting continued deferral treatment as discussed in more detail in the direct testimony of Company witness Myers.

<u>LPS</u>

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for the LPS.

A. The Company plans to invest $15.225 million in the 16-month projected bridge period and $13.282 million in the projected test year in the LPS, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 57, columns (h) and (j), respectively. These capital investments will be implemented during periodic outages in 2025 through 2027. It is important to note that none of these investments are associated with resolving the Toshiba defects. Those investments are being recorded to a regulatory asset pursuant to the MPSC's May 18, 2023 Order in Case No. U-21310.

Q. What is the basis for the projected $15.225 million capital investment in the 16-month projected bridge period?

A. The projected $15.225 million capital investment in the 16-month projected bridge period will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are six projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 21-26. The basis for those projects is described below:

- Ludington Units 1 through 6 DCS Control Relay Replacement ($2,971,797). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS – Lower Penstock Expansion Joint ("LPEJ") Chamber Waterstop replacement ($2,009,804). The scope of this project is the replacement of the LPEJ waterstop and potentially dewatering the surrounding groundwater. The engineering study was performed in 2020 at a cost of $0.404 million and project implementation began in 2021 and is planned to be completed in May 2025. In 2021, the engineering was completed, and the design was approved by FERC; and

  The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period;

- Ludington 1 Pony Motor Overhaul ($2,266,667). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Replace 480V Dike Load Center ("DLCs") ($1,287,697). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Governor Replacement ($2,026,247). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington; and

- Station Water Discharge Isolation Valve ($1,161,403). The scope of work will consist of the installation of a separate, parallel train oil water separator ("OWS") to that of the plant's existing modification of existing support systems (station sump, station sump pumps, & metering devices) to support new OWS, and retrofit of existing OWS to improve oil separability. This will allow temporary use of the modified original OWS while servicing the anticipated new one so as to not impact unit availability. The Station Water Discharge Header Isolation Valve and Oil Separator was previously approved into the LTFP to assess the stations OWS due to off process conditions that had resulted in reportable releases of oil into Lake Michigan. The main goal of this project was to perform formal engineering evaluation of the plant's existing OWS to identify if it could likely serve the facility thought the current relicensing period (2069) without major modification or replacement. In the intervening time since that project was initiated, however, two separate reportable oil releases (as of March 8, 2022) have occurred (Dec 2021 & Jan 2022). During evaluation of these events, prior documentation & engineering analysis (1140-319-001 OIL WATER SEPARATOR) of the existing OWS was located that indicates it has suffered numerous failures in the past and is not effective at removing contaminates from the influent to satisfy the facilities mandated NPDES effluent requirements. As stipulated by the project charter, "Should the above engineering evaluation conclude that significant changes are needed to the separator or system configuration to meet current environmental and regulatory standards a new project and LTFP funding request will be initiated to implement these changes and utilize the engineering design basis established within this project." With the discovery of the aforementioned documentation pertaining to the plant's current OWS (1140-319-001), the justified conclusion is that significant modifications to the system will be necessary to meet current and future environmental standards. Therefore, this project will establish the funding request to implement those changes to the facility and utilize the previously approved project to provide detailed engineering for such modification.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Station Power Transformer Life Cycle Management ($442,156). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Replace Barrier Net Panels ($400,010). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS Intake Gate and Gate House Mechanical Replacement ($425,376). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Centralized Grease System Replacement ($303,300). The current electro-pneumatic grease system(s) that service the wicket gate bushings are functioning past their service life and are of questionable reliability (original plant equipment). Most of the components have worn seals, leak grease, and have basic function. Replacement of end of service life components such as pumps, distributing blocks, and solenoid valves. This project will modernize the existing control system to a self-diagnostic PLC system;

- Ludington All Unit Critical Valve and Actuator Replacement ($487,713). The scope of this project is to replace valves, actuators, and associated equipment critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism; and

- Fifteen additional projects at LPS totaling $1.443 million, with each individual project representing $240,522 or less in expenditures. These projects include Guide Bearing Oil Float Replacement, all unit flow transmitter replacement, ABB/Governor air compressors, Inlet 17 outlet corrugated pipe replacement, oil processing equipment replacement, and small tools, pumps, motors, valves, and instrumentation.

Q. What is the basis for the projected $13.282 million capital investment in the projected test year?

A. The projected $13.282 million capital investment in the projected test year will fund numerous safety, regulatory compliance, reliability, and infrastructure projects. There are four projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 18 through 21. The basis for these projects is described below:

- DCS Control Relay Replacement ($2,906,676). The scope of this project is to replace and eliminate worn and less reliable control relays with new electronic I/O modules and new relays where needed. The number of hardware control relays will be reduced due to the “control” being performed in logic instead of “hardwired” circuits. This will increase reliability and reduce outages and unit derates. Common control and monitoring of system equipment allows operation of the equipment from the HMI graphics and keeps the operator focused on one system instead of monitoring several systems from several areas of the control room.

  The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

  The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end-of-life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System (“DAS”), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Ludington 1 Pony Motor Overhaul ($2,800,000). The project will remove and replace the existing pony motor rotors with new rotors that will provide another 50 years of service. It is assumed that the stators on both units can be reused, and that the new rotor will be designed to work with the existing stator and liquid rheostat. The new rotor will be redesigned to ensure that fatigue is no longer an issue for the remaining life of the plant.

  During the overhaul of Unit 1 (performed by Toshiba in 2018 and 2019), a Non-Destructive Examination ("NDE") test performed on the pony motor rotor structure recorded linear indications, a.k.a. cracks, in presumed high stress locations. Consumers Energy requested analysis by Toshiba at that time to confirm the stress state of the rotor in operation, but Toshiba did not complete it (note that while the Company requested this analysis from Toshiba, pony motor replacement was not part of Toshiba's scope for the overhaul). Prior to re-assembly after the major overhaul work, the linear indications had been repaired by Toshiba. The unit experienced problems with fastener failures after being returned to service, and subsequent inspections identified that the linear indications (cracks) returned, and that the indications continued to grow in volume and size with use of the pony motor. Unit 1's pony motor was subsequently removed from service and the indications continue to be tracked with regular inspections. Since the pony motor is no longer used to start the unit in pump mode, the indications have not grown, nor have new indications been noted. However, an analysis acquired by Toshiba at the Company's request has subsequently shown that the rotor material is beyond its fatigue life limit, which explains the continued crack growth with Unit 1's pony motor use. The major risk is that if cracks begin to grow again, the whole unit must be taken off line to protect the rest of the unit from failure. The pony motor will remain unavailable to start the unit as a pump until the pony motor rotor is replaced. And if the cracks begin to propagate again, the unit will be taken off line entirely until the pony motor rotor can be replaced;

- Replace 480V DLCs ($1,352,043). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of $0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance; and

- Governor Replacement ($2,125,719). The scope of this project is to contract with a specialized vendor to inspect, repair as required, and modernize the unit governors. The LPS unit governors have not been overhauled in approximately 15 years and, as a result, show signs of significant wear.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- LPS Commons Station Power Transformer ("SPT") Life Cycle Management ($643,137). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare;

- Intake Gate and Gate House Mechanical Replacement ($937,863). The LPS intake gates and associated hoist equipment are the primary form of mechanical protection for the LPS units. Their purpose is to isolate the stored energy from the reservoir's water against each unit's penstock when dewatering or during emergency conditions such as a penstock rupture or governor failure. Reliable operation of this system is critical to minimize damages from a unit run away condition or a penstock failure, acting as a last effort to control unit overspeed. The mechanical system of the intake gate hoist is all original (circa 1971) and recent OEM inspection revealed that its condition is poor and in need of refurbishment. Updates and repairs are required to support the current facility license extension of 2069. The electrical control system is well past its design service life. This outdated technology is obsolete, and certain critical components are no longer available for spare parts. Modern technology offers more reliable options that would give the system an additional 30 years of service. The head gate hoist is enclosed in a steel structure on top of the intake (head gate enclosure). The head gate hoist enclosures are original to the plant and have rusted out in many places. Significant corrosion has been noted on the steel frame, the connections, and the beams. These enclosures need to be replaced as they are beyond a repair option;

- Generator Potential Transformer and Enclosure Project ($605,621). Each LPS Unit utilizes six Potential Transformers ("PT") for Unit metering and regulating. A PT converts high primary voltage into a measurable low secondary voltage. The Metering PTs are utilized for indication of the Unit I/O and for the Disturbance Monitoring Equipment ("DME"). The Regulating PTs are utilized for Unit control and protection schemes. The current Unit metering and regulating PTs are plant original and have surpassed their life expectancy of 20-30 years. Occasionally, there have been unexplainable Unit trips due to a "PT Fail" alarm captured by the unit Exciters. This could be caused by a PT starting to fail. Most PT casings show their age in the form of cracks and separation of the molded casing. This can allow moisture ingress and internal insulating material loss. This can cause corrosion and overheating, ultimately leading to failure of the PT. The PTs are unlikely to last another 5-10 years and are suspected in the unexplained Unit trips. The PT enclosures are also original to the plant. There are three enclosures per unit, one for each phase (X,Y,Z). Each of the enclosures houses two drawers for the PTs, one regulating and one metering PT. The drawers have become difficult to open and close due to worn hardware. The enclosures also create a section of Isophase Phase Bus ("IPB") Duct for the IPB that connects the unit to the Starting Bus. This section of IPB Duct has been showing signs of damage due to eddy currents. This area is also a common Temporary Ground locations for workers protection during Unit and Starting Bus maintenance. The enclosure doors, where temporary grounds are installed, utilize an insert and bolt. These inserts increasingly become dislodged and fall into the Starting Bus. This causes emergent Working Clearance requirements to retrieve the inserts, so damage can't be caused by these inserts. Once an insert becomes dislodged, the insert hole becomes enlarged, and the insert can't be re- installed;

- Replace Barrier Net Panels ($369,000). The panels are a regulatory required system to minimize fish entrainment. The panel replacements are primarily time based. LPS has extensive operating experience with these panels, which helps determine when a replacement is required; and

- Sixteen additional projects at Ludington totaling $1.542 million, with each individual project representing $227,778 or less in capital expenditures. These projects include Main Transformer Bank ("MTB") isophase cooling blower replacement, oil processing equipment replacement, guide bearing oil float replacement, unit thrust bearing strainer & differential pressure transmitter replacement, flow transmitter replacement, and small tools, pumps, motors, valves, and instrumentation.

ADMINISTRATIVE AND OTHER

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for Administrative and Other.

A. The Company plans to invest $17.782 million in the 16-month projected bridge period and $11.050 million in the projected test year in Administrative and Other, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 64, columns (h) and (j), respectively.

Q. What is the basis for the projected $17.782 million capital investment in the 16-month projected bridge period for Administrative and Other?

A. The projected $17.782 million capital investment in the 16-month projected bridge period will fund environmental, reliability, and infrastructure projects. There are two projects which are greater than $1 million, and they are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 27-28. The basis for those projects is described below:

- Wastewater Treatment System ($12,400,004). This project spans the 16-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Administrative and other;

- Lakeshore Administration Building ($3,702,428). The scope of this project is to move the machine shop. The existing machine shop is located at the Campbell site and with the closure of the Campbell units on May 31, 2025, the Company will have to relocate the existing machine shop. Options for the project include (1) doing nothing and going to third parties for parts which will impact both cost and timing of delivery, (2) purchasing another machine shop, (3) section off the training center at Campbell and move the machine shop to that building, and (4) building a machine shop in a centralized location to better service all generation sites.

  The machine shop has proven its financial viability, routinely producing annual revenues that are near or exceed annual operating costs. That trend is expected to continue based on projections. The shop's ability to quickly turn around projects and fabricate parts faster and at a lower cost than external vendors has led to substantial savings, particularly in replacement power costs, estimated at $300k annually.

- In addition to the two projects above, there are eight additional projects totaling $1.679 million. These projects include generation cyber security, laptop and capital business tool purchases for, Electric Supply, Environmental Services, Lab Services, Business Planning and Administration, and Enterprise Project Management.

Q. What is the basis for the projected $11.050 million capital investment in the projected test year?

A. The projected $11.050 million capital investment in the projected test year will fund regulatory compliance, reliability, and infrastructure projects. There is one project which is greater than $1 million, and it is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 22. The basis for this project is described below:

- Wastewater Treatment System ($9,600,001). As discussed in more detail earlier in this direct testimony, the scope of this project is the treatment of wastewater that will continue to be generated at the Campbell site following cessation of coal generation in May 2025. The Company considered several options to address the ongoing leachate water, including transport for offsite disposal, offsite treatment, on site treatment and onsite disposal. Ultimately, on-site disposal via a deep injection well was selected and is currently being permitted by EGLE and EPA. The Company also submitted an NPDES permit application revision on November 7, 2024; and

- In addition to the project described above, there are eight additional projects totaling $1.412 million. These projects include generation cyber security, laptop and capital business tool purchases for Electric Supply, Environmental Services, Lab Services, Business Planning and Administration, and Enterprise Project Management.

<u>BATTERY ENERGY STORAGE SYSTEMS</u>

Q. Please explain the Company's projected capital expenditures for the 16-month projected bridge period ending April 30, 2026 and the projected test year ending April 30, 2027 for BESS.

A. The Company plans to invest $70.614 million in the 16-month projected bridge period and $26.392 million in the projected test year in Company-owned battery resources, as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 3, line 71, columns (h) and (j), respectively.

Q. What is the basis for the projected $70.614 million capital investment in the 16-month projected bridge period?

A. The projected $70.614 million capital investment in the 16-month projected bridge period will fund BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than $1 million and are presented on Exhibit A-12

(RTB-3), Schedule B-5.2, page 8, lines 29 through 30. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected $26.392 million capital investment in the projected test year?

A. The projected $26.392 million capital investment in the projected test year will fund the BESS. This entire investment amount is reflected in two separate projects, Iosco and Weadock, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 23 through 24. The basis for those projects is described in the direct testimony of Company witness Clark.

<u>GENERATION CAPITAL EXPENDITURES—SUMMARY</u>

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark provides additional discussion in his direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, Lean Organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-43 (RTB-4), page 1, Generation Operation and Maintenance Expenses.

A. Exhibit A-43 (RTB-4), page 1, identifies the actual 2024 through 12-Months-Ending April 30, 2027 projected Generation O&M expenses. Specifically:

- Column (a) identifies each O&M expense category;
- Column (b) identifies the Actual 2024 Generation O&M expense as \$128,438,405;
- Column (c) identifies the 16-month Projected Bridge Period Generation O&M expense as \$150,445,403; and

- Column (d) identifies the Projected Test Year Generation O&M expense as $103,732,461.

HISTORICAL O&M EXPENSE

Q. How does Consumers Energy determine the level of Generation O&M spending?

A. Consumers Energy tracks the history and projects the future maintenance needs of each generating unit. Personnel at the plants provide information on maintenance for each site or specific units. Once costs to operate and comply with regulations are prioritized, the Asset Strategy and Generation Planning organizations evaluate the plans required to maintain and/or improve the condition of the plant – weighing the estimated benefit to the customer for each project. Using this combination of information, a preliminary plan is prepared and reviewed to ensure high-priority issues are addressed and adequate resources and funding are available. After all appropriate levels of management have reviewed and approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – "Base," "Environmental Operations," "Major Maintenance," and "Retention and Separation."

Q. What are Base O&M expenses?

A. Base O&M expenses comprises two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company's generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to (1) fuel (diesel and gasoline) for equipment and vehicles, (2) material,

(3) tools, (4) cleaning supplies, (5) facilities, (6) security, and (7) road and grounds maintenance.

Q. Please explain how the 2024 Actual O&M expenses were developed.

A. The 2024 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 16-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the 16-month projected bridge period ending April 30, 2026, and projected test year ending April 30, 2027 shown on Exhibit A-43 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2024 through the projected test year demonstrates average annual decreases of approximately 9.0%. As discussed later in this direct testimony, this average annual decrease primarily reflects a change in the mix of the Company's owned generating assets including the movement of renewable energy resources to the Company's renewable energy plans. Exhibit A-43 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Campbell site. These expenses were required for the safe and reliable operation of Karn Units 1 and 2 through their May 2023 retirement and Campbell Units 1, 2, and 3 through their May 2025 retirement.

Q. How do the historical and projected test year O&M expense amounts compare to prior years?

A. The 2024 historical O&M expense amount of $128.438 million and the projected test year O&M expense amount of $103.732 million compare favorably to the actual O&M expense amount for 2022; the 2022 generation O&M expense amount was $150.031 million. The projected test year O&M expense amount of $103.732 million also compares favorably to the actual O&M expense amount for 2023: the 2023 generation O&M expense amount was $118.848 million. As I previously stated, the O&M expense reductions reflect a mix of generation asset changes, changes in major maintenance projects and expenses, cost recovery realignment, and waste reduction measures.

Q. Please explain Exhibit A-43 (RTB-4), page 2.

A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or contract rate to historical O&M expense. Column (b) presents the historical O&M expense. Column (c) presents the amount of the historical O&M amount to which an inflation rate or contract rate applies. Columns (e) and (g) present the amounts to which an inflation rate or contract rate were applied for each period, respectively. Columns (d), (f), and (h) present contract and inflation increases for each respective period. Amounts that were projected using other methods are included in column (i). Column (j) is the projected test year O&M and is the sum of columns (b), (d), (f), (h), and (i).

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4), page 2.

A. The historical labor on line 1, column (b) reflects a combination of both Operating Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of 2.1%, 2.4%, and 2.4% were applied to labor on line 1, material on line 2, contractor on line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d), (f), and (h).

Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test year projected O&M expense amount of $103.732 million reflects that evaluation. Within the test year projected amount of $103.732 million, there are a number of adjustments that result in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustments that are reflected in the test year projected amount of $103.732 million.

A. As previously discussed Karn Units 1 and 2 retired on May 31, 2023 pursuant to a Settlement Agreement in the Company's 2018 IRP and the Settlement Agreement reached in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025 and the addition of Covert Units 1, 2 and 3 on June 1, 2023. In addition, several O&M groups have changed O&M expenses, all of which I will discuss later in this direct testimony.

Q. Please discuss the O&M expense for Karn Units 1 and 2.

A. The 2024 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for the Karn site in 2024 was $14.653 million versus the projected O&M for the test year at $14.829 million, a modest annual increase of approximately 0.51%. 2024 represented the first full year of Karn operation without Karn Units 1 and 2. A complete discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2, and 3.

A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units will have ceased operation in May 2025, prior to the end of the bridge period. The projected test year expense for Campbell is $0.279 million, a $41.061 million reduction from the actual 2024 O&M expense of $41.340 million. A complete discussion of the test year major maintenance for Campbell Units 1, 2, and 3 is described later in this direct testimony.

Q. Please discuss the increase in total O&M expense for Covert Units 1, 2, and 3.

A. The 2024 O&M expense for Covert reflects the Company's first full year of operation for Covert after taking ownership of the plant on June 1, 2023. The actual O&M expense for Covert Units 1, 2, and 3 in 2024 was $13.508 million, and the projected O&M for the test year is $14.858 million, with the biggest increase reflected in major maintenance. The 2024 expense for major maintenance was $6.553 million however it is projected to total $7.771 million in the test year. A complete discussion of the test year major maintenance for Covert is described later in this direct testimony. The environmental operations expense and the base O&M are relatively flat from the historic year to the test year.

Q. Please discuss the increase in total O&M expense for Ludington.

A. The projected test year total O&M expense for Ludington reflects an increase of $2.263 million from the historical year to the test year. The projected test year total O&M expense is $11.661 million as compared to the historical year total O&M expense of $9.399 million. A large portion of the increase in the projected test year total O&M expense is attributable to a $1.394 million increase in major maintenance expense. A complete discussion of the test year major maintenance for Ludington is described later in this direct testimony. The balance of the increase is reflected in the base O&M expense increase of $0.860 million.

Q. What is the basis for the increase in Ludington base O&M expense?

A. The 2024 base O&M expense for Ludington totaled $6.017 million and the projected test year base O&M expense is $6.877 million. There are three projects which primarily led to that increase: (1) FERC Assessments, (2) license initiatives, and (3) fish protection. The Company's 51% share of 2024 historical O&M expense for these projects was $1.272 million, $1.872 million and $2.135 million respectively, for a total of $5.280 million. The Company's share of the projected test year O&M expense for these three projects is $1.442 million, $2.321 million, and $2.361 million respectively, for a total of $6.123 million. The increase in projected expense for these three projects totals $0.843 million, consistent with the overall base O&M increase. Each of these projects are required as part of the Company's FERC 50-year license and, as such, cannot be avoided.

Q. Please discuss the increase in O&M expense for the River Hydros.

A. The projected test year total O&M expense for the River Hydros reflects an increase of $3.944 million from the historical year to the test year. The projected test year total O&M expense is $15.261 million as compared to the historical year total O&M expense of $11.317 million. Most of the increase in the projected test year total O&M expense is attributable to a $2.964 million increase in major maintenance expense. A more complete discussion of the test year major maintenance for the River Hydros is described later in this direct testimony. The balance of the increase is reflected in base O&M expense, an increase of $0.969 million from $6.474 million in the historical year to $7.444 million in the projected test year.

Q. Why should the Commission approve the Company's projected River Hydro O&M expense?

A. Regardless of the ultimate decision on whether to divest, relicense, or decommission the respective River Hydro facilities, the O&M expenses requested in this case are needed to appropriately operate and maintain those facilities to ensure they are safe and legally compliant. The current timeline for divestiture would not likely result in a decision to divest prior to the start of the test period on May 1, 2026. As such, the Company will need to continue to maintain and operate the River Hydros through a portion of the test year, at a minimum.

Further, should the divestiture not be achieved, the Company would need to continue to operate and maintain the River Hydros until such time that a decision to relicense or decommission the River Hydros is made. Even with a decision to decommission the River Hydros, a process that would take more than 20 years, the

Company would need to continue to operate and maintain the River Hydros until which time they are decommissioned.

Q. How does the Company propose to protect customers from excessive rates if the full projected O&M expense for the test year is not required?

A. The Company requests the Commission to approve a one-way tracker for the River Hydro O&M expense. To the extent that future determinations obviate the need to reasonably and prudently spend the Company's projected test year O&M expense for the River Hydros, the Company proposes to refund the difference between the projected and actual amount of O&M expense.

Q. What does the Company mean with respect to one-way tracker?

A. The Company only intends to refund the difference between the projected River Hydro O&M expense and the actual River Hydro O&M expense in the event that actual expenses are lower than projected, it does not propose to recover additional O&M expenses should actual River Hydro O&M expense exceed the projected River Hydro O&M expense.

Q. Please discuss the increase in total O&M expense for Administration and Generation Commons.

A. The projected increase in total O&M expense for Administration and Generation Commons totals $5.684 million and is due to a number of factors including the reorganization of the Lean Organization, Enterprise Project Management tools and filling of vacancies, and operations reliability spending. While much of this funding is initially budgeted for Administration and Generation Commons, the actual O&M expense will ultimately be assigned to the individual plants at which the work is performed.

Q. Are the changes discussed above the only reasons for the overall reduced O&M expense?

A. No. The Company has implemented other focused cost reductions that have directly impacted both the projected bridge period and test year expense. These cost reductions were primarily achieved through individual waste reduction projects.

Q. Please discuss some examples of waste reduction projects.

A. I will discuss two of the projects with the largest identified savings. The first project is the "Nine Year Unit Mechanical Interval Inspection and Replacement" project at Ludington. The Company evaluated the annual scope and was able to extend the inspections without adding risk to the equipment. The Company's projected test year spend for this major maintenance project is $358,000 as compared to the projected spend of $570,000 in its prior electric rate case, Case No. U-21585.

Another specific project is the "Capacity Factor Used For Water and Chemicals" project at Covert. The Company identified a way to minimize the required water requirements for the year through improved process and scheduling, resulting in a savings of approximately $300,000. While the total projected cost for this major maintenance project is slightly higher than that same project presented in the prior electric rate case, Case No. U-21585, the projected cost presented in this case is much lower than it would have been otherwise.

<u>ENVIRONMENTAL OPERATIONS</u>

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the environmental operations of the Company's AQCS. As Federal and State emissions standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation.

On a historical basis, the largest portion of this expense was incurred at the Company's Karn and Campbell coal units. However, with the 2023 retirement of Karn Units 1 and 2 and the May 31, 2025 retirement of Campbell Units 1, 2, and 3, the total projected environmental operations expense has dropped significantly as I will discuss later in this direct testimony.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending April 30, 2026 and test year ending April 30, 2027 were calculated.

A. Environmental Operations expenses have primarily been a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites on a historical basis. The operations component was primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2024 historical expense of $8.539 million to the projected test year expense of $2.045 million reflects a cost reduction of $6.439 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. Beyond May 2025, most of the environmental expense is associated with the continued operation of Karn Units 3 and 4 as well as projected environmental O&M expense at the gas-fired generating units, Ludington, and the River Hydros.

Q. What is the projected drop in Environmental Operations expense for the Campbell site?

A. The actual O&M expense for environmental operations for the Campbell site in 2024 was $6.513 million. The projected test year O&M expense for environmental operations for the Campbell site is $0, a reduction of $6.513 million. As such, the balance of the environmental operations O&M expense is basically flat from 2024 to the projected test year, a very reasonable projection.

<u>MAJOR MAINTENANCE</u>

Q. What are Major Maintenance expenses?

A. Major Maintenance represents O&M projects that are based on asset condition or on historic maintenance intervals over multiple years. To maintain and improve the performance of the generating fleet, the Company performs Major Maintenance on a regular basis. However, completion of Major Maintenance work can be influenced by, among other things, actual operations of the generating units, availability of parts and labor, and energy market conditions.

Q. Please explain how the Major Maintenance O&M expenses for the 16-month projected bridge period ending April 30, 2026 and test year ending April 30, 2027 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

Q. Please identify the test year Major Maintenance O&M expenses.

A. The Company projects that it will incur $32.982 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4, column (d). Test year Major Maintenance expense by generating unit is presented on Exhibit A-43 (RTB-4), page 3, column (d).

Q. Why is Consumers Energy spending $32.982 million in total Major Maintenance O&M expense during the projected test year ending April 30, 2027?

A. The Company is spending the majority of its total Major Maintenance expense during the test year to maintain reliability. Reliability related Major Maintenance O&M expenses, made predominantly during scheduled outages, allow the plants to avoid equipment issues that would lead to more frequent random outages, exposing customers to potentially more expensive replacement energy and capacity at market prices. Minimizing forced outages by maintaining equipment improves the likelihood the unit will be available when needed and minimizing damage that could result in the event of a catastrophic failure.

Q. Are Major Maintenance expenses relatively consistent from year to year?

A. No. Although the Company attempts to plan for controlled and consistent levels of Major Maintenance, because Major Maintenance outages occur relatively infrequently, for an individual unit, it is very possible to have significant year-by-year variations in the number, duration, and magnitude of the required Major Maintenance work. Other factors such as unforeseen equipment failure, emerging industry initiatives, unit dispatch, expected power prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

Q. Is it possible that changes to the Company's forecasted Major Maintenance plan could occur?

A. Yes. It is possible that the Company's forecasted Major Maintenance plan could change. Equipment condition can change such that the timing of maintenance activities may need to be accelerated or delayed. The Company attempts to make the best decision in balancing the cost and risks associated with the operation of the equipment and attempts to minimize the cost to customers. Factors such as weather, equipment and labor availability, energy market conditions, and electrical system stability considerations can affect the actual timing of an outage and maintenance spending.

Q. Do Major Maintenance costs vary by individual generating unit(s)?

A. Yes. While the Company's natural gas generating units are similar in age, they vary in size, type, and design, so do the costs to maintain these units. As discussed earlier in this direct testimony, the Company has LTSAs for its Covert, Jackson and Zeeland plants, with two different OEMs. Because of these differences, the LTSA payments will vary significantly from plant to plant as well as OEM to OEM.

Q. Is it common for an electric utility to have different sizes, types, designs, and dispatch of generating units in its generation portfolio?

A. Yes. Consumers Energy is not unique in that its fleet contains units of different size, type, and design.

Q. What are the categories of Major Maintenance?

A. Major Maintenance is broken into two categories—outage and non-outage.

Q. Please describe what is included in the outage major maintenance O&M expense.

A. Outage major maintenance O&M expenses are those associated with major overhauls and require that the generating unit be removed from service for HRSGs and/or turbine inspections and maintenance. These outages are typically scheduled on a periodic basis and are required by law, insurance providers, LTSA inspections based upon unit operating hours, and/or industry standards to ensure operational safety and reliability. One example of a major maintenance outage is the periodic disassembly and repair of turbine control and stop valves. The valves control the amount of steam going to the turbine and are needed to control the unit output. During an emergency situation, for example during unit electrical trip, the valves must react very quickly to stop the steam going to the turbine to prevent it from overspeeding. Overspeeding the turbine can result in severe mechanical damage resulting in a very long duration outage to repair, further resulting in increased cost to customers for market priced electricity during the outage. Periodic maintenance of turbine valves is required for personnel and equipment safety. Maintaining the valves on a periodic basis ensures that the clearances and internal components operate as designed and can reliably stop the turbine quickly when needed to prevent turbine or generator damage.

Q. Please describe the work completed in a boiler inspection.

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

Q. Please describe the work completed in a turbine inspection.

A. Turbine inspections consist of disassembling, inspecting, and cleaning the different components of the turbine. During the inspection, worn or damaged parts are repaired or replaced to specific tolerances. Because of the extreme conditions under which these units operate, the demand for uninterrupted power, and dangers associated with operating these large pieces of equipment, industry standards recommend that inspections be completed every seven years.

Q. Please define non-outage maintenance.

A. Non-outage maintenance O&M costs typically do not require the generating unit be removed from service, but they are still critical to the operation of the unit. An example of non-outage maintenance is Mill/Pulverizer maintenance.

<u>Campbell Site Major Maintenance</u>

Q. Please describe Campbell Site Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, lines 1 and 2, column (d), Campbell Units 1, 2, and 3 Major Maintenance expense is forecasted to be $0.279 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projected to spend $0.279 million in Major Maintenance on the Campbell units in the projected test year ending April 30, 2027?

A. Although the Campell units will be retired on May 31, 2025, environmental regulations require the continued maintenance of the site landfill, water treatment plant, and site Rod Assisted Pipe system.

<u>Karn Units 1 and 2 Major Maintenance</u>

Q. Please describe Karn Units 1 and 2 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 3, column (d), Karn Units 1 and 2 Major Maintenance expense is forecasted to be $0.0 million in the projected test year ending April 30, 2027.

<u>Covert Plant Major Maintenance</u>

Q. Please describe the Covert Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 8, column (d), the Covert Plant Major Maintenance expense is forecasted to be $7.771 million in the projected test year ending April 30, 2027, and includes:

- Covert Plant LTSA Major Maintenance ($2,628,820). This is the major maintenance portion of the Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected major maintenance expenses are based upon variable fees paid to Mitsubishi for maintenance services which are based on an effective fired hours basis pursuant to the LTSA. Unlike the General Electric LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected premature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units;

- Covert Plant LTSA extra work Major Maintenance ($1,585,000). This is the major maintenance portion of the Mitsubishi negotiated services that are not covered in the planned normal maintenance of each generating unit. Based on historical outage experience, there are typical discovery items found on this style of gas turbines that are not part of the LTSA planned maintenance scope. Some of the typical items not covered under the LTSA that need to be addressed are labor and material to replace the following: blading, ammonia delivery system, SCR catalyst, turbine rotors, cooling towers, and turbine cooling air cooler;

- Covert Plant Capacity Factor Used For Water and Chemicals ($1,300,000). This item provides for the city water used by the Covert Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Reverse Osmosis System ("RO"), operation agreement ($471,667). The scope of this project is to contract with a third party to operate and maintain the RO system;

- Covert Plant Base Outage Funding – Boiler plant equipment ($425,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- Covert Plant HEPS/FAC/DAST Inspections ($712,500). This project will include the performance of regulatory required HEPS, DAST mid cycle inspection, and FAC inspection; and

- Six additional projects for Covert totaling $648,269 in expenses, with each individual project representing $238,702 or less in expenses. These projects include SCR cleaning annual maintenance, NERC relay and Direct Current ("DC") testing, ITC Transmission Co switchyard upgrades, gas turbine exhaust expansion joints repairs, and main inlet filters.

Karn Units 3 and 4 Major Maintenance

Q. Please describe Karn Units 3 and 4 Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 4, column (d), Karn Units 3 and 4 Major Maintenance expense is forecasted to be $1.824million in the projected test year ending April 30, 2027, and includes:

- Karn Units 3 and 4 Periodic Outage Major Maintenance ($300,000). The scope of this project is to perform boiler maintenance activities during scheduled periodic outages during the projected test year. Expenses include planning, engineering services, materials, and overtime labor;
- Site Commons uninterruptible power supply ("UPS") preventative maintenance ($160,000). The scope of this project is to perform the required preventive maintenance on the UPS system;
- Karn Units 3 and 4 Opacity Improvements ($150,000). Karn Units 3 and 4 are unable to run on oil and gas without having opacity excursions. This project will perform critical maintenance and repairs on the equipment related to these opacity issues; and
- Fourteen additional projects for Karn Units 3 and 4 totaling $1.214 million in expenses, with each individual project representing $140,000 or less in expenses. These projects include critical motor major maintenance, boiler required repairs, breaker maintenance, boiler pendant cleaning, and main & station power transformer testing.

Zeeland Plant Major Maintenance

Q. Please describe Zeeland Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 6, column (d), Zeeland Plant Major Maintenance expense is forecasted to be $5.419 million in the projected test year ending April 30, 2027, and includes:

- Zeeland Plant LTSA — Running Maintenance Contract ($2,395,766). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Zeeland Plant Capacity Factor Used for Water and Chemicals ($1,293,615). This item provides for the city water used by the Zeeland Plant, and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use;

- Base Outage — Boiler Plant Equipment ($566,667). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments;

- Large Oil Filled Transformer maintenance ($250,000). The scope of this project is to execute the 20-year major maintenance plan which includes (1) drain/process/reclaim oil, (2) perform internal inspections when drained, (3) perform planned repairs and evaluate as found conditions, and (4) perform electrical testing to internal circuits and supporting electrical components; and

- Seventeen additional projects totaling $912,700 in expenses, with each individual project representing $213,033 or less in expenses. These include drum level control valve overhaul, excitation and isolation transformer testing and maintenance, HEPS, FAC inspection, breaker maintenance, and NERC-required relay testing.

Jackson Plant Major Maintenance

Q. Please describe Jackson Plant Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 7, column (d), Jackson Plant Major Maintenance expense is forecasted to be $4.112 million in the projected test year ending April 30, 2027. This forecasted expense consists of:

- Jackson Plant Capacity Factor Used for Water and Chemicals ($2,722,395). This item provides for the city water used by the Jackson Plant and for the chemicals required to operate the water purification systems that are used to purify the makeup water prior to use. The projected expense is based upon historical monthly invoice values as well as consideration of the capital project previously discussed in this testimony for site generating water;

- Jackson Plant Non-LTSA Turbine and jet engine repairs ($400,000). The scope of this major maintenance is to perform jet engine repairs including bushing replacements every 12,000 hours;

- Jackson Plant LTSA — Running Maintenance Contract ($500,000). Consumers Energy has a long-term maintenance agreement with General Electric to perform the major maintenance and capital repairs necessary to maintain unit reliability. This item represents the O&M component of that service agreement;

- Jackson Plant Base Outage - Boiler plant equipment ($250,000). During planned and scheduled periodic outages, inspections and repairs are performed. Base boiler maintenance and outage is needed to complete condition assessment inspections of the boiler and major components, complete repairs on valves and large plant equipment, and complete repairs that are identified during shutdowns and condition assessments; and

- Five additional projects totaling $240,081 with each individual project representing $75,000 or less in expenses. These include pre-filter replacement, turbine building temperature control maintenance, chiller condenser cleaning, and NERC relay testing.

<u>LPS Major Maintenance</u>

Q. Please describe LPS Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 9, column (d), LPS Major Maintenance expense is forecasted to be $4.708 million in the projected test year ending April 30, 2027, including:

- Fish Barrier Net - Installation, cleaning, and repairs and removal ($2,182,503). This is a FERC regulatory requirement. The net is installed annually and maintained to meet FERC license requirements (and the requirements of a Settlement Agreement with federal and state natural resource agencies) and minimizes the impact of LPS on fish in Lake Michigan;

- Trench Feature Work ($450,000). FERC Part 12 requires inspections to be performed on reservoirs every 5 years. This project includes performing a dam safety inspection on the upper reservoir clay liner, scour features, erosion gullies and tailrace. The annual reservoir inspection includes multi-beam sonar and side scan of the upper reservoir as well as a multi-beam sonar on the tailrace. The project is to perform engineering remediation on defects found and perform silica placement as necessary to remain compliant with FERC regulations;

- Scour Feature Repair Phase 2 and 3 ($585,667). The project scope includes repairing the scour features on Units 1 and 6 by placing rip rap in the areas where rip rap has been displaced by the newer and more powerful pumping units. Construction would include filling the Unit 1 and Unit 6 scour feature areas with rip rap and fill voids with concrete, and placing 2" of concrete between the rip rap on the entire width of the rip rap apron to a length of about 400'. This would lock in the rip rap throughout the entire width of the 2' rip rap apron and prevent the rip rap apron from being scoured away.

  The rip rap apron has experienced more scour due to the upgraded pumping units. The rip rap gets displaced, exposing the filter cloth underneath the rip rap and protecting the clay liner. Once the filter cloth is exposed, it historically has gotten ripped by the pumping units and exposed to the clay liner and potential scour. During the 2019 trench features inspection, the exposed fabric was ripped, exposing the clay liner in front of Unit 6 and allowing for the clay liner to be scoured away. The rip rap apron in front of Unit 1 has also experienced scour, which has moved riprap stone and exposed fabric on top of the clay liner. Since October 2019, the area of exposed clay in front of Unit 6 has grown from 6' diameter to 20' diameter and 1.5' of the 7-8' clay liner has scoured away.

  The Company has committed to FERC that it would engineer a repair to address these recurring issues in 2020; engineering was complete in April 2020 and submitted to FERC for FERC approval. In February 2020, the Dam Safety Surveillance Monitoring Committee ("SMC") created threshold action levels for the scour features in concurrence with the Engineer of Record for the scour feature repair. At 0-1 ft of scour of the clay liner, no actions are necessary. At 1-2 ft of scour of the clay liner, the scour feature shall be inspected in the next May or October outage. At 2-4 ft of scour of the clay liner, an emergent repair is needed;

- Nine Year Unit Mechanical Interval Inspection and Replacement ($358,000). The scope of this project is to perform replacement of common wear elements and consumable items associated with the pump/turbine units. This work will include the first nine-year maintenance interval for each of the six;

- Generator Circuit Breaker ("GCB") Pumping Pole Maintenance ($200,000). This project will fund the work scope to annually rebuild the pump poles across the site to restore their operational life as per the GCB maintenance strategy. Expected duty cycles and wear rates observed will require the site to average one pump pole set per year with an associated cost around $200k annually for the site to perform the required maintenance items to restore. This project is only for the pump poles and not the generating poles.

The GCB contact assembly is configured with both main and arcing contacts. The arcing contacts are designed to be "sacrificial" to prolong the main contact life. The GCB cannot safely operate under a fault condition once the arcing contact life is expended at 25% life remaining, which will force the unit to be unavailable in pump mode operations until the proper maintenance is performed. The GCB pole maintenance must be addressed in a planned outage prior to reaching 25% calculated life remaining to mitigate costs of an individual outage just for GCB maintenance; and

- Twenty-three additional projects totaling $932,059, with each individual project representing less than $161,000 in expenses. These include Station Drainage Sump and oil/water separator cleaning, wicket gate repair, Depression Air Compressor Maintenance, periodic outage inspections and non-destructive examination, 480v Transfer bus clean and inspection, and Non-Destructive Inspection Of Insulated And Critical Piping Systems.

<u>Hydro Major Maintenance</u>

Q. Please describe Hydro Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 10, column (d), Hydro Major Maintenance expense is forecasted to be $8.374 million in the projected test year ending April 30, 2027, and includes:

- Hydro License Initiatives ($2,107,041). A FERC requirement, this item resulted from the relicensing of Au Sable, Manistee, and Muskegon River dams, with the main result being that the Company has annual license commitments. License commitments include some recreation, fish payments, and water quality such as upwelling systems licenses;

- Hydro annual FERC Dam Safety Requirements including Part 12 Inspections ($1,441,220). The scope of this project is to perform the FERC-required dam safety inspections on an annual basis, and the FERC-required Part 12 inspections on each dam every five years. A similar level of expense, including modest escalation, is budgeted annually from 2026 through 2029;

- Foote Auxiliary Spillway Pilot Channel and Embankment Crest Grading Project ($1,000,000). The scope of this project is to develop a design to raise or fill the existing auxiliary spillway pilot channel/ditch. In addition, repairs to the observed rutting and grading the right embankment crest, along with placing new fill as needed, will bring the embankment to a consistent elevation of 647.0 feet. This also includes the non-corewall section embankment widening, dependent on the results from the stability analyses.

Raising the elevation of the auxiliary spillway pilot channel/ditch would reduce the chance of the auxiliary spillway being activated. Repairing the rutting and placing new fill on the embankments would increase the slope stability factor of safety, thus reducing the chance of dam failure. This project will meet FERC requirements and mitigate regulatory compliance risk.

The Part 12D Dam safety inspection by an independent consultant noted several critical issues with the Foote Auxiliary Spillway. Flow within the auxiliary spillway would initiate in the pilot channel/ditch at approximately elevation 641 feet, which is 0.9 feet below the current Probable Maximum Flood elevation of 641.9 feet. Additionally, rutting was observed on the right embankment, and the elevation survey of the left embankment showed a decrease of approximately 0.7 feet at Station 0+50 since the August 2013 survey. Elevations measured from Sta. 1+00 to Sta. 7+50 were below the nominal embankment crest of elevation 647.0 feet, with a minimum of elevation 646.6 feet at Sta. 3+00.

Failure to comply with the Dam safety inspection recommendations could result in regulatory agency action, including fines and potential loss of the facility's operating license. For this project, the risk being mitigated is not the risk of a probable maximum flood happening but the risk of FERC citing the company for regulatory non-compliance and assessing fines accordingly. This risk is significant given inspection result recommendations and operating license commitments.

- Hardy Intake Tower Brick Repair ($800,000). The scope of this project is to replace all the deteriorated interior brick inside the intake tower for the full height. The Hardy intake tower brickwork has been slowly deteriorating for the last few years. The bricks are crumbling to the touch and there are areas with significant delamination throughout the entire height of the walls (34ft). If the deterioration becomes significant enough, it may impact the headgate hoists and the head gates installation safety of the Operations staff;

- Tippy Spillway Chamber Inspections and Repairs ($292,667). The project scope includes performing spillway chamber inspections, engineering for spillway chamber repairs and construction of repairs. The Tippy spillway chambers are hollow chambers underneath the spillway. In the spillway chambers, the concrete is deteriorated, rebar is exposed, and there is seepage present;

- Hydro Concrete Repairs ($243,100). The scope of this project is to make necessary repairs to deteriorating concrete at all 13 River Hydro facilities. This budgeted amount will allow for the performance of necessary repairs which are identified after spring flows or general deterioration. The identification of large concrete repairs will be considered in the annual budgeting process;

- Five Channels Intake Deck Beam Bottom Side Repairs ($240,000). The scope of this project is the completion of partial depth concrete repairs and cleaning and applying coatings to steel areas of degradation. This option removes the areas that have experienced degradation and thereby eliminates the ongoing debris loading hazard.

  The Five Channels intake deck over the penstocks is a reinforced concrete slab, spanning upstream to downstream between intermediate concrete and steel support beams running (dam convention) left to right between penstock walls. The underside of the slab and support beams are exposed to the penstock environment. In 2018 a Condition Assessment was completed of the Five Channels Unit 1 and Unit 2 penstocks. From this assessment, it was identified that the reinforced concrete beam at the upper to lower deck transition in both Units 1 and 2 had experienced concrete spalling with reinforcement being exposed. Similarly, the steel beams supporting concrete haunches to the deck above had corrosion and spalling concrete. During the 2022 Headgate replacement project, these assessments were updated, revealing significant progression of deterioration on the Unit 2 concrete beam, with the lower layer of reinforcement completely exposed, and the second layer partially exposed. Unit 1 had similar progression, to a lesser extent. The problem associated with these observations is that the degraded/missing concrete and exposed reinforcement compromises the strength of the beam, and by extension the deck. The concrete spalling represents a debris hazard for concrete debris to the turbines below;

- Cooke Powerhouse Divider wall Pier ($206,667). The scope of this project is to assess the condition of the divider pier between the powerhouse and the spillway and make repairs as needed to the diagonal cracking observed during the dive inspections and additional deterioration noted above water. The Part 12D independent consultant and third-party condition assessment consultant noted significant diagonal cracking in the divider pier between the powerhouse and the training wall (log chute) during the dive inspection. The underwater inspection indicated the diagonal crack is approximately 11-feet long and up to 3/8” wide. The diagonal cracking may be indicative of settlement. Other minor cracks, spalls, erosion, efflorescence, delamination, and vegetation growing in cracks are also located on the divider pier; and

- Thirty-one additional projects totaling $2,043,000 with each individual project representing $180,000 or less in expenses. These projects include Tippy and Cooke Log Chute Concrete Repairs, base outage funding, headgate evaluation and repairs, relief well piezometer cleaning, and condition/risk assessments.

Admin and Other Major Maintenance

Q. Please describe Admin and Other Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 12, column (d), Admin and Other Major Maintenance expense is forecasted to be $0.150 million in the projected test year ending April 30, 2027 and includes one project: Generation control systems cyber maintenance software support. Specifically, this project provides funding for software maintenance contracts from multiple vendor systems that are not part of the DCS control vendor service contracts.

Classic 7 Major Maintenance

Q. Please describe Classic 7 (Cobb, Weadock, and Whiting units) Major Maintenance expenses for the projected test year ending April 30, 2027.

A. As shown on Exhibit A-43 (RTB-4), page 3, line 5, column (d), Classic 7 Major Maintenance expense is forecasted to be $0.218 million in the projected test year ending April 30, 2027.

Q. Why is Consumers Energy projecting to spend $0.218 million in Major Maintenance on the Classic 7 units in the projected test year ending April 30, 2027?

A. Although the Classic 7 units were retired in 2016, environmental regulations require the continued maintenance of the on-site ash ponds, which includes Cobb landfill and ash pond O&M, Weadock landfill license and inspections, and Whiting ash pond post-closure care.

KARN AND CAMPBELL RETENTION AND SEPARATION PLAN EXPENSE

Q. What are the projected costs for the Company's Karn and Campbell Retention and Separation plans?

A. As reflected on Exhibit A-43 (RTB-4), page 1, line 5, the Company incurred actual expense of $8.626 million in 2024, and is projecting expense of $5.182 million in the 16-month projected bridge period ending April 30, 2026. The actual 2024 expense of $8.626 million is based upon expense of $0.495 million for Karn and $8.626 million for Campbell. The 16-month projected bridge period expense of $5.182 million is entirely based upon expense of $5.182 million for Campbell. There is no projected test year expense.

Q. Is the Company requesting O&M recovery of the $5.182 million projected amount for the projected bridge period?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in Electric Rate Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2024 through the projected bridge period ending April 30, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Daly supports regulatory asset treatment of these expenses in his direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan was a people strategy that the Company had implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold and dark time period following retirement. The cold and dark condition refers to the period following plant retirement and prior to plant decommissioning. During this period, limited environmental remediation and perhaps partial demolition is performed. The facility may be physically secured with fencing and other measures to prevent vandalism or theft so as to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

Q. What is the purpose of the retention component of the Company's plan?

A. The Company had a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component allowed the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 became increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company had the ability to hire new employees, the training time necessary for any new hires provided a significant challenge to operating the units both safely and reliably. The retention component utilized the best practices that the Company employed in retiring the Classic 7.

Q. What is the purpose of the separation component of the Company's plan?

A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers varies based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles of their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Karn retention and separation plan?

A. The Karn retention and separation plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Karn retention and separation plan.

A. The retention benefits associated with the Karn retention and separation plan include three payment components: a signing incentive, annual incentives, and a final retention incentive.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in October 2019. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Karn until October 31, 2020 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31, 2020, the employee forfeited the signing incentive.

Employees received an annual incentive which graduated from 20% to 30% of their base pay for service each November in years 2019, 2020, and 2021, for staying at Karn and rendering service for the next 12 months. The employee had to stay at Karn until October 31 of the following year to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days. If the employee separated from the Company before October 31 of the next year, the employee forfeited the annual incentive. Eligible employees received their first annual incentive payment in November 2020, a second payment in November 2021, and a third payment in November 2022.

Employees received their final retention incentive equal to 60% of their base pay following plant retirement if the employee was still at Karn. The payment was intended to incentivize employees to stay until the plant went cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

Q. Please describe the severance benefits associated with the Karn retention and separation plan.

A. The severance benefits associated with the Karn retention and separation plan includes initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why did the Company anticipate the need to make severance payments associated with the retirement of Karn Units 1 and 2?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (11 within 60 miles of the Karn site) to which employees could relocate, than it did in 2016. As such, the Company anticipated the need to make severance payments to those employees that could not find placement. As I previously stated, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees.

Q. Please explain the relevant details of the collective bargaining agreement for OM&C employees.

A. The collective bargaining agreement for OM&C employees, in Article VII, Section 17, and the Generation Operations Coal Closing Agreement provide that employees will be placed in either a corresponding position, or if none exists, in a vacant position he/she is qualified to perform within 60 miles of his/her current headquarters. Per Article XVII of the collective bargaining agreement, employees who are released due to lack of work, and are not placed as described above, are provided a separation allowance consisting of straight time pay for five regular workdays for each year of continuous service with the Company. Due to the lack of Company locations within 60 miles of Karn Units 1 and 2, as described above, it was anticipated that some employees would be eligible for a separation allowance.

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date. This incentive program is the same program that is currently in place for employees at the Karn site.

Q. What is the purpose of the retention component of the Company's plan?

A. For similar reasons described in the Karn retention plan, the Company had a strong interest in keeping qualified employees working at the Campbell site through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. Similar to the situation at the Karn site, it was increasingly difficult to hire new employees at the Campbell site given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires provided a significant challenge to operating the three units both safely and reliably.

Q. What is the purpose of the separation component of the Company's plan?

A. After the Campbell units are retired, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

Q. What are the benefit types associated with the Campbell retention plan?

A. Similar to the Karn retention and separation plan, the Campbell retention plan includes three benefit types: retention benefits, severance benefits, and relocation and moving costs.

Q. Please describe the retention benefits associated with the Campbell retention plan.

A. The retention benefits associated with the Campbell retention plan include three payment components: a signing incentive, periodic incentives, and a final retention incentive. The timeline for retention benefits reflects approval of the Settlement Agreement in the Company's 2021 IRP in June 2022.

Employees received a signing incentive equal to 15% of their base pay if they signed a retention agreement in July 2022. By signing the retention agreement, the employee agreed to forfeit their transfer rights under the current working agreement (for union employees) or under Company policy (for exempt and non-exempt employees). The employee had to stay at Campbell until October 31, 2022 to receive the payment; if the employee stayed until that date, the incentive was paid out to the employee within 30 days.

If the employee separated from the Company before October 31, 2022, the employee forfeited the signing incentive.

Employees received a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell and rendering service for a certain period. Specifically, for service provided July 2022 through October 2022, employees received 20% of their base pay. For service provided November 2022 through October 2023, employees received 25% of their base pay. For service provided November 2023 through October 2024, employees received 30% of their base pay. The employee must stay at Campbell until October 31 of the given year to receive the payment; if the employee stays until that date, the incentive was/will be paid out to the employee within 30 days. If the employee separates from the Company before October 31 of the given year, the employee forfeits the annual incentive.

Employees receive a final retention incentive equal to 60% of their base pay on or about October 31, 2025, if the employee is still at Campbell. The payment is intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the 12 months prior to the payment.

Q. Please describe the severance benefits associated with the Campbell retention plan.

A. The severance benefits associated with the Campbell retention plan include initial recognition of a severance benefit to be paid, recognition of additional severance earned (one week of pay per year of service), and recognition of the accretion of a final severance benefit.

Q. Why does the Company anticipate the need to make severance payments associated with the retirement of Campbell Units 1, 2, and 3?

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees who desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (seven within 60 miles of the Campbell site) to which employees can relocate, than it did in 2016. In addition, the Company also retired two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees who cannot find placement. As I previously stated, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees, as previously discussed for the Karn retention and separation plan.

Q. Does this conclude your direct testimony?

A. Yes, it does.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Case No.: U-21870
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
Page: 1 of 9
Witness: RTBlumenstock
Date: June 2025

Generation Capital Expenditures
($000)

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No.	Description	12 Months Ended 12/31/2024	12 Mos Ended 12/31/2025	4 Mos Ending 4/30/2026	16 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027
1	Steam Power Generation					
2	Environmental	$ -	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 22,814	$ 9,200	$ 3,278	$ 12,478	$ 8,304
4	Total Steam Production	$ 22,814	$ 9,200	$ 3,278	$ 12,478	$ 8,304
5	Hydraulic Power Generation					
6	Routine and Small CapEx	$ -	$ -	$ -	$ -	$ -
7	Total hydraulic production	$ -	$ -	$ -	$ -	$ -
8	Pumped Storage Generation					
9	Ludington Overhaul	$ -	$ -	$ -	$ -	$ -
10	Routine and Small CapEx	$ 2,710	$ 11,418	$ 3,807	$ 15,225	$ 13,282
11	Total Pumped Storage Generation	$ 2,710	$ 11,418	$ 3,807	$ 15,225	$ 13,282
12	Other Production Plant					
13	Routine and Small CapEx	$ 119,728	$ 173,227	$ 74,477	$ 247,705	$ 167,051
14	Total Other Production Plant	$ 119,728	$ 173,227	$ 74,477	$ 247,705	$ 167,051
15	SubTotal	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638
16	Less Contingency	$ -	$ -	$ -	$ -	$ -
17	Grand Total	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638

	(a)	(b)	(c)	(d)	(e)
		Projected			
		4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
1	Steam Power Generation				
2	Environmental	$ -	$ -	$ -	$ -
3	Routine and Small CapEx	$ 1,763	$ 10,715	$ 8,304	$ 20,782
4	Total Steam Production	$ 1,763	$ 10,715	$ 8,304	$ 20,782
5	Hydraulic Power Generation				
6	Routine and Small CapEx	$ -	$ -	$ -	$ -
7	Total hydraulic production	$ -	$ -	$ -	$ -
8	Pumped Storage Generation				
9	Ludington Overhaul				$ -
10	Routine and Small CapEx	$ 3,928	$ 11,296	$ 13,282	$ 28,507
11	Total Pumped Storage Generation	$ 3,928	$ 11,296	$ 13,282	$ 28,507
12	Other Production Plant				
13	Routine and Small CapEx	$ 89,789	$ 157,916	$ 167,051	$ 414,755
14	Total Other Production Plant	$ 89,789	$ 157,916	$ 167,051	$ 414,755
15	SubTotal	$ 95,480	$ 179,928	$ 188,638	$ 464,045
16	Less Contingency	$ -	$ -	$ -	$ -
17	Grand Total	$ 95,480	$ 179,928	$ 188,638	$ 464,045

Schedule: B-5.2

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Case No.: U-21870
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
Page: 2 of 9
Witness: RTBlumenstock
Date: June 2025

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		Projected Bridge Period						Projected Test Year	
Line No.	Description	12 Months Ended 12/31/2024		12 Months Ending 12/31/2025		4 Months Ending 4/30/2026		16 Months Ending 4/30/2026		12 Months Ending 4/30/2027	
1	**JHCampbell 1&2**	**$ (1,510)**		**$ -**		**$ -**		**$ -**		**$ -**	
2	Contractor		$ (1,274)		$ -		$ -		$ -		$ -
3	Labor		$ (193)		$ -		$ -		$ -		$ -
4	Materials		$ 131		$ -		$ -		$ -		$ -
5	Business Expenses		$ (20)		$ -		$ -		$ -		$ -
6	Contingency		$ -		$ -		$ -		$ -		$ -
7	Other (Loadings, Chargebacks)		$ (154)		$ -		$ -		$ -		$ -
8	**JHCampbell 3**	**$ (1,264)**		**$ -**		**$ -**		**$ -**		**$ -**	
9	Contractor		$ (1,007)		$ -		$ -		$ -		$ -
10	Labor		$ (200)		$ -		$ -		$ -		$ -
11	Materials		$ 150		$ -		$ -		$ -		$ -
12	Business Expenses		$ (36)		$ -		$ -		$ -		$ -
13	Contingency		$ -		$ -		$ -		$ -		$ -
14	Other (Loadings, Chargebacks)		$ (171)		$ -		$ -		$ -		$ -
15	**DEKarn 1&2**	**$ -**		**$ -**		**$ -**		**$ -**		**$ -**	
16	Contractor		$ -		$ -		$ -		$ -		$ -
17	Labor		$ -		$ -		$ -		$ -		$ -
18	Materials		$ -		$ -		$ -		$ -		$ -
19	Business Expenses		$ -		$ -		$ -		$ -		$ -
20	Contingency		$ -		$ -		$ -		$ -		$ -
21	Other (Loadings, Chargebacks)		$ -		$ -		$ -		$ -		$ -
22	**DEKarn 3&4**	**$ 25,587**		**$ 9,200**		**$ 3,278**		**$ 12,478**		**$ 8,304**	
23	Contractor		$ 18,333		$ 8,648		$ 3,081		$ 11,729		$ 7,806
24	Labor		$ 937		$ -		$ -		$ -		$ -
25	Materials		$ 1,450		$ -		$ -		$ -		$ -
26	Business Expenses		$ 56		$ -		$ -		$ -		$ -
27	Contingency		$ -		$ -		$ -		$ -		$ -
28	Other (Loadings, Chargebacks)		$ 4,812		$ 552		$ 197		$ 749		$ 498
29	**Zeeland**	**$ 45,025**		**$ 52,002**		**$ 15,273**		**$ 67,275**		**$ 40,023**	
30	Contractor		$ 34,570		$ 48,882		$ 14,356		$ 63,239		$ 37,621
31	Labor		$ 588		$ -		$ -		$ -		$ -
32	Materials		$ 3,250		$ -		$ -		$ -		$ -
33	Business Expenses		$ 67		$ -		$ -		$ -		$ -
34	Contingency		$ -		$ -		$ -		$ -		$ -
35	Other (Loadings, Chargebacks)		$ 6,550		$ 3,120		$ 916		$ 4,037		$ 2,401
36	**Jackson Generating Station**	**$ 15,255**		**$ 18,778**		**$ 5,712**		**$ 24,489**		**$ 28,143**	
37	Contractor		$ 11,661		$ 17,651		$ 5,369		$ 23,020		$ 26,455
38	Labor		$ 273		$ -		$ -		$ -		$ -
39	Materials		$ 1,539		$ -		$ -		$ -		$ -
40	Business Expenses		$ 5		$ -		$ -		$ -		$ -
41	Contingency		$ -		$ -		$ -		$ -		$ -
42	Other (Loadings, Chargebacks)		$ 1,777		$ 1,127		$ 343		$ 1,469		$ 1,689
43	**Covert**	**$ 30,712**		**$ 45,054**		**$ 22,491**		**$ 67,545**		**$ 61,443**	
44	Contractor		$ 23,628		$ 42,350		$ 21,142		$ 63,492		$ 57,756
45	Labor		$ 113		$ -		$ -		$ -		$ -
46	Materials		$ 3,377		$ -		$ -		$ -		$ -
47	Business Expenses		$ 26		$ -		$ -		$ -		$ -
48	Contingency		$ -		$ -		$ -		$ -		$ -
49	Other (Loadings, Chargebacks)		$ 3,568		$ 2,703		$ 1,349		$ 4,053		$ 3,687

MICHIGAN PUBLIC SERVICE COMMISSION **Schedule: B-5.2**

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Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Historical Year		**Projected Bridge Period**						**Projected Test Year**	
Line No.	**Description**	**12 Months Ended 12/31/2024**		**12 Months Ending 12/31/2025**		**4 Months Ending 4/30/2026**		**16 Months Ending 4/30/2026**		**12 Months Ending 4/30/2027**	
50	**Hydros**	**-**		**-**		**-**		**-**		**-**	
51	Contractor		-		-		-		-		-
52	Labor		-		-		-		-		-
53	Materials		-		-		-		-		-
54	Business Expenses		-		-		-		-		-
55	Contingency		-		-		-		-		-
56	Other (Loadings, Chargebacks)		-		-		-		-		-
57	**Ludington**	**2,710**		**11,418**		**3,807**		**15,225**		**13,282**	
58	Contractor		3,299		18,041		6,015		24,055		20,986
59	Labor		402		-		-		-		-
60	Materials		885		-		-		-		-
61	Business Expenses		449		-		-		-		-
62	Contingency		-		-		-		-		-
63	Other (Loadings, Chargebacks)		(2,325)		(6,622)		(2,208)		(8,830)		(7,704)
64	**Admin and Other**	**5,748**		**14,809**		**2,973**		**17,782**		**11,050**	
65	Contractor		3,476		12,564		2,585		15,149		9,550
66	Labor		92		-		-		-		-
67	Materials		2,149		-		-		-		-
68	Business Expenses		79		-		-		-		-
69	Contingency		-		-		-		-		-
70	Other (Loadings, Chargebacks)		(48)		2,244		388		2,633		1,501
71	**Battery Storage**	**22,988**		**42,585**		**28,029**		**70,614**		**26,392**	
72	Contractor		16,777		36,470		24,004		60,473		22,602
73	Labor		207		-		-		-		-
74	Materials		2,475		-		-		-		-
75	Business Expenses		5		-		-		-		-
76	Contingency		-		-		-		-		-
77	Other (Loadings, Chargebacks)		3,525		6,115		4,025		10,140		3,790
78	**All Other Environmental**	**-**		**-**		**-**		**-**		**-**	
79	Contractor		-		-		-		-		-
80	Labor		-		-		-		-		-
81	Materials		-		-		-		-		-
82	Business Expenses		-		-		-		-		-
83	Contingency		-		-		-				-
84	Other (Loadings, Chargebacks)		-		-		-		-		-
85	**Total Capital**	145,252	145,252	193,846	193,846	81,562	81,562	275,408	275,408	188,638	188,638

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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	**Description**	**4 Mos Ending 4/30/2025**	**12 Mos Ending 4/30/2026**	**12 Mos Ending 4/30/2027**	**28 Mos Ending 4/30/2027**
1	**JHCampbell 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
2	Contractor	$ -	$ -	$ -	$ -
3	Labor	$ -	$ -	$ -	$ -
4	Materials	$ -	$ -	$ -	$ -
5	Business Expenses	$ -	$ -	$ -	$ -
6	Contingency	$ -	$ -	$ -	$ -
7	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
8	**JHCampbell 3**	**$ -**	**$ -**	**$ -**	**$ -**
9	Contractor	$ -	$ -	$ -	$ -
10	Labor	$ -	$ -	$ -	$ -
11	Materials	$ -	$ -	$ -	$ -
12	Business Expenses	$ -	$ -	$ -	$ -
13	Contingency	$ -	$ -	$ -	$ -
14	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
15	**DEKarn 1&2**	**$ -**	**$ -**	**$ -**	**$ -**
16	Contractor	$ -	$ -	$ -	$ -
17	Labor	$ -	$ -	$ -	$ -
18	Materials	$ -	$ -	$ -	$ -
19	Business Expenses	$ -	$ -	$ -	$ -
20	Contingency	$ -	$ -	$ -	$ -
21	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
22	**DEKarn 3&4**	**$ 1,763**	**$ 10,715**	**$ 8,304**	**$ 20,782**
23	Contractor	$ 1,635	$ 10,094	$ 7,806	$ 19,535
24	Labor	$ -	$ -	$ -	$ -
25	Materials	$ -	$ -	$ -	$ -
26	Business Expenses	$ -	$ -	$ -	$ -
27	Contingency	$ -	$ -	$ -	$ -
28	Other (Loadings, Chargebacks)	$ 127	$ 621	$ 498	$ 1,247
29	**Zeeland**	**$ 33,232**	**$ 34,043**	**$ 40,023**	**$ 107,298**
30	Contractor	$ 32,099	$ 31,140	$ 37,621	$ 100,860
31	Labor	$ -	$ -	$ -	$ -
32	Materials	$ -	$ -	$ -	$ -
33	Business Expenses	$ -	$ -	$ -	$ -
34	Contingency	$ -	$ -	$ -	$ -
35	Other (Loadings, Chargebacks)	$ 1,133	$ 2,903	$ 2,401	$ 6,438
36	**Jackson Generating Station**	**$ 4,499**	**$ 19,991**	**$ 28,143**	**$ 52,633**
37	Contractor	$ 4,340	$ 18,680	$ 26,455	$ 49,475
38	Labor	$ -	$ -	$ -	$ -
39	Materials	$ -	$ -	$ -	$ -
40	Business Expenses	$ -	$ -	$ -	$ -
41	Contingency	$ -	$ -	$ -	$ -
42	Other (Loadings, Chargebacks)	$ 158	$ 1,311	$ 1,689	$ 3,158
43	**Covert**	**$ 16,058**	**$ 51,487**	**$ 61,443**	**$ 128,988**
44	Contractor	$ 14,977	$ 48,515	$ 57,756	$ 121,248
45	Labor	$ -	$ -	$ -	$ -
46	Materials	$ -	$ -	$ -	$ -
47	Business Expenses	$ -	$ -	$ -	$ -
48	Contingency	$ -	$ -	$ -	$ -
49	Other (Loadings, Chargebacks)	$ 1,080	$ 2,972	$ 3,687	$ 7,739

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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)
		Projected			
Line No.	Description	4 Mos Ending 4/30/2025	12 Mos Ending 4/30/2026	12 Mos Ending 4/30/2027	28 Mos Ending 4/30/2027
50	**Hydros**	**$ -**	**$ -**	**$ -**	**$ -**
51	Contractor	$ -	$ -	$ -	$ -
52	Labor	$ -	$ -	$ -	$ -
53	Materials	$ -	$ -	$ -	$ -
54	Business Expenses	$ -	$ -	$ -	$ -
55	Contingency	$ -	$ -	$ -	$ -
56	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
57	**Ludington**	**$ 3,928**	**$ 11,296**	**$ 13,282**	**$ 28,507**
58	Contractor	$ 6,865	$ 17,190	$ 20,986	$ 45,041
59	Labor	$ -	$ -	$ -	$ -
60	Materials	$ -	$ -	$ -	$ -
61	Business Expenses	$ -	$ -	$ -	$ -
62	Contingency	$ -	$ -	$ -	$ -
63	Other (Loadings, Chargebacks)	$ (2,937)	$ (5,893)	$ (7,704)	$ (16,534)
64	**Admin and Other**	**$ 2,477**	**$ 15,305**	**$ 11,050**	**$ 28,832**
65	Contractor	$ 2,145	$ 13,004	$ 9,550	$ 24,699
66	Labor	$ -	$ -	$ -	$ -
67	Materials	$ -	$ -	$ -	$ -
68	Business Expenses	$ -	$ -	$ -	$ -
69	Contingency	$ -	$ -	$ -	$ -
70	Other (Loadings, Chargebacks)	$ 332	$ 2,300	$ 1,501	$ 4,133
71	**Battery Storage**	**$ 33,523**	**$ 37,091**	**$ 26,392**	**$ 97,006**
72	Contractor	$ 28,709	$ 31,764	$ 22,602	$ 83,075
73	Labor	$ -	$ -	$ -	$ -
74	Materials	$ -	$ -	$ -	$ -
75	Business Expenses	$ -	$ -	$ -	$ -
76	Contingency	$ -	$ -	$ -	$ -
77	Other (Loadings, Chargebacks)	$ 4,814	$ 5,326	$ 3,790	$ 13,930
78	**All Other Environmental**	**$ -**	**$ -**	**$ -**	**$ -**
79	Contractor	$ -	$ -	$ -	$ -
80	Labor	$ -	$ -	$ -	$ -
81	Materials	$ -	$ -	$ -	$ -
82	Business Expenses	$ -	$ -	$ -	$ -
83	Contingency	$ -	$ -	$ -	$ -
84	Other (Loadings, Chargebacks)	$ -	$ -	$ -	$ -
85	**SubTotal**	$ 95,480	$ 179,928	$ 188,638	$ 464,045
86	**Less Contingency**	$ -	$ -	$ -	$ -
87	**Grand Total**	$ 95,480	$ 179,928	$ 188,638	$ 464,045

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Generation Capital Expenditures

	(a)	(b)	(c)	(d)	(e)	(f)
		Historical Year	Projected Bridge Period			Projected Test Year
Line No.	Description	12 Months Ended 12/31/2024	12 Months Ending 12/31/2025	4 Months Ending 4/30/2026	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027
1	Contractor	$ 109,462	$ 184,607	$ 76,551	$ 261,158	$ 182,776
2	Labor	$ 2,219	$ -	$ -	$ -	$ -
3	Materials	$ 15,405	$ -	$ -	$ -	$ -
4	Business Expenses	$ 632	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 17,533	$ 9,239	$ 5,011	$ 14,250	$ 5,862
	Total	$ 145,252	$ 193,846	$ 81,562	$ 275,408	$ 188,638

	(a)	(b)	(c)	(d)	(e)	(f)
		Projected				
Line No.	Description	12 Months Ended 12/31/2024	4 Months Ending 4/30/2025	16 Months Ending 4/30/2026	12 Months Ending 4/30/2027	28 Months Ending 4/30/2027
1	Contractor	$ 109,462	$ 90,771	$ 261,158	$ 182,776	$ 443,934
2	Labor	$ 2,219	$ -	$ -	$ -	$ -
3	Materials	$ 15,405	$ -	$ -	$ -	$ -
4	Business Expenses	$ 632	$ -	$ -	$ -	$ -
5	Contingency	$ -	$ -	$ -	$ -	$ -
6	Other (Loadings, Chargebacks)	$ 17,533	$ 4,709	$ 14,250	$ 5,862	$ 20,111
	Total	$ 145,252	$ 95,480	$ 275,408	$ 188,638	$ 464,045

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Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Work Item Description	(g) Projected Amount	(h) Actual Amount
1	2024	Gas Generation	Covert	Non-Routine	Condition-based	Long Term Service Agreement - Running capital contrac	$ 19,004	$ 15,623
2	2024	Gas Generation	Covert	Routine	Condition-based	Netmation (MHPSA Operating System & 4S) - Unit 1-3	$ 4,596	$ 6,047
3	2024	Gas Generation	Covert	Routine	Environmental	Long Term Service Agreement - Extra Work Unit 2	$ 750	$ 1,340
4	2024	Gas Generation	Covert	Routine	Environmental	HRSG Expansion Joint Replacements	$ -	$ 1,284
5	2024	Gas Generation	Jackson	Routine	Condition-based	1-6 Feedwater Desuperheater Valve	$ 831	$ 1,871
6	2024	Gas Generation	Jackson	Routine	Condition-based	GE Long Term Service Agreement FFH	$ 12,213	$ 8,615
7	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Unit 5 generator step up transformer rewinc	$ 9,135	$ 9,696
8	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Site Spare GSU	$ 590	$ 2,040
9	2024	Gas Generation	Zeeland	Routine	Condition-based	P2 599 699 345kV Breaker Replcmnt	$ 320	$ 1,856
10	2024	Gas Generation	Zeeland	Routine	Condition-based	Zeeland Long Term Service Agreement - Running Capital Contrac	$ 19,641	$ 21,699
11	2024	Gas Generation	Zeeland	Non-Routine	Condition-based	Heat recovery steam generator Casing Replacement	$ 2,739	$ 2,840
12	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 distributed control system Evergreer	$ 1,295	$ 1,191
13	2024	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Karn 3 Cooling Tower Internal Structure Replacemen	$ 3,919	$ 4,183
14	2024	Gas/Oil Generation	Karn 3	Routine	Condition-based	Karn 3 Combustion Air Heater	$ 2,500	$ 1,354
15	2024	Gas/Oil Generation	Karn commons	Routine	Condition-based	Karn 3&4 Sync Wire Replacement	$ 1,458	$ 1,260
16	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Boiler Plant Heating Project	$ 3,055	$ 4,467
17	2024	Gas/Oil Generation	Karn commons	Non-Routine	Condition-based	Karn 3&4 Tank Farm Heating Line Replacemen	$ 1,230	$ 1,217
18	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New Electrical System from Weadock Sub for Karn 3 and 4	$ -	$ 1,524
19	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	Discharge Line Reroute for K 3 and 4 Sump Water	$ -	$ 1,905
20	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New building to house new fire water systen	$ -	$ 1,019
21	2024	Gas/Oil Generation	Karn commons	Non-Routine	Asset Separation	New 46kV to 4160 transformer to repower facilities	$ -	$ 3,065
22	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Iosco Battery Energy Storage System (IRP)	$ 21,458	$ 9,107
23	2024	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Weadock Battery Energy Storage System (IRP)	$ 31,819	$ 13,011
24	**Total 2024 Projects**						**$ 136,553**	**$ 116,212**

Note:
(1) Projected amounts were taken from Case No. U-21585, Staff Exhibit S-16.1 Page 1 of 2 and workpapers.

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Generation Capital Expenditures

Line No.	(a) Calendar Period	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(f) Full Internal Budget Approval	(g) Work Item Description	(h) Projected Amount
1	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	Purchase of site spare GSU	$1,500
2	Bridge Period	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)	$1,305
3	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Units 1-3 Emerson DCS Evergreen	$2,156
4	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract	$26,246
5	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3	$2,922
6	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 2 - LTSA Capital - Extra work not included in contract	$12,153
7	Bridge Period	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract	$9,010
8	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU	$1,333
9	Bridge Period	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement	$1,336
10	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH	$16,200
11	Bridge Period	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	LTSA Capital - Extra work not included in contract	$2,115
12	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel staging	$43,697
13	Bridge Period	Gas Generation	Zeeland	Routine	Condition-based	Class 3	Approved	LTSA - Extras not included in contract (cranes, mobile equipment)	$4,703
14	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements	$10,175
15	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer	$2,341
16	Bridge Period	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	Unit 5 GSU Transformer Rewind	$2,430
17	Bridge Period	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$2,700
18	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 2	Approved	ID Fan Inlet Damper Replacements	$2,700
19	Bridge Period	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$3,000
20	Bridge Period	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$1,800
21	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement	$2,972
22	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul	$2,267
23	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement	$2,026
24	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC	$1,288
25	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Replace Lower Penstock Expansion Joint	$2,010
26	Bridge Period	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Station Water Discharge Isolation Valve	$1,161
27	Bridge Period	Admininstration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System	$12,400
28	Bridge Period	Admininstration	Admin	Non-Routine	Infrastructure	Class 2	Approved	Lakeshore Admin Building	$3,702
29	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)	$30,053
30	Bridge Period	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)	$40,561
31	**Total Bridge Period Projects**								**$248,262**

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-12 (RTB-3)
Schedule: B-5.2
Page: 9 of 9
Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of Actual and Projected Electric Capital Expenditures
For the years 2024 through 2027
($000's)

Generation Capital Expenditures

Line No.	(a) Calendar Year	(b) Tier 1 Portfolio	(c) Tier 2 Portfolio	(d) Project Type	(e) Project Classification	(f) Class of Cost Estimate	(g) Full Internal Budget Approval	(h) Work Item Description	(i) Projected Amount
1	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 2	Approved	Purchase of site spare GSU	$5,910
2	Test Year	Gas Generation	Covert	Non-Routine	Condition-based	Class 3	Approved	LCI Replacements (SFC)	$2,610
3	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 1	Approved	Long Term Service Agreement - Running capital contract	$18,812
4	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 2	Approved	Netmation (MHPSA Operating System & 4S) - Units 1-3	$8,844
5	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 1 - LTSA Capital - Extra work not included in contract	$9,525
6	Test Year	Gas Generation	Covert	Routine	Condition-based	Class 4	Approved	Unit 3 - LTSA Capital - Extra work not included in contract	$4,093
7	Test Year	Gas Generation	Jackson	Non-Routine	Condition-based	Class 3	Approved	Purchase of site spare GSU	$2,333
8	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 1	Approved	GE Long Term Service Agreement FFH	$12,810
9	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Engine 191-306 Overhaul	$6,130
10	Test Year	Gas Generation	Jackson	Routine	Condition-based	Class 3	Approved	Unit 7 gas turbine rotor replacement	$1,664
11	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 1	Approved	LTSA/Phase I Gas Turbine Advanced gas path replacement and axial fuel sta	$8,331
12	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 3	Approved	Phase II Turbine Replacements	$10,175
13	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Phase II GT Advanced gas path replacement and axial fuel staging	$13,923
14	Test Year	Gas Generation	Zeeland	Non-Routine	Condition-based	Class 2	Approved	Purchase of Site Spare Generator Step up transformer	$4,481
15	Test Year	Gas/Oil Generation	Karn 3	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$1,800
16	Test Year	Gas/Oil Generation	Karn 4	Non-Routine	Condition-based	Class 3	Approved	Combustion Air Heater Replacement	$2,250
17	Test Year	Gas/Oil Generation	Karn Commons	Non-Routine	Condition-based	Class 3	Approved	Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$1,800
18	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1 Pony Motor Overhaul	$2,800
19	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 1-6 DCS Control Relay Replacement	$2,907
20	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington Governor Replacement	$2,126
21	Test Year	Hydro Generation	Ludington	Non-Routine	Condition-based	Class 3	Approved	Ludington 480 Volt Motor Control Centers for DLC	$1,352
22	Test Year	Admininstration	Admin	Non-Routine	Environmental	Class 2	Approved	Wastewater Treatment System	$9,600
23	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Iosco Battery Energy Storage System (IRP)	$11,457
24	Test Year	Renewables - IRP Battery	Battery Storage	Non-Routine	New Storage	Class 3	Approved	Weadock Battery Energy Storage System (IRP)	$14,934
25	**Total Test Year Projects**								**$160,668**

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)

Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

GENERATION OPERATION AND MAINTENANCE EXPENSES

Line No.	(a) Description		(b) Historical 12 Months Ended 12/31/2024		(c) Projected Bridge Period 16 Months Ending 04/30/2026		(d) Projected Test Year 12 Months Ending 04/30/2027
1	**BASE O&M**	$	91,056	$	105,324	$	68,705
2	**ADJUSTED O&M**						
3	Environmental Operations	$	8,539	$	5,110	$	2,045
4	Major Maintenance	$	28,844	$	40,012	$	32,982
5	Retention & Separation	$	8,626	$	5,182	$	-
6	**TOTAL O&M**		**128,438**		**150,445**		**103,732**

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)
Page: 2 of 3
Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Description**	**2024 Actual**	**Base O&M for Merit & Inflation 12 Mos Ended Dec 31, 2024**	**Merit & Inflation 12 Mos Ending Dec 31, 2025**	**Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2025**	**Merit & Inflation 12 Mos Ending Dec 31, 2026**	**Base O&M for Merit & Inflation 12 Mos Ending Dec 31, 2026**	**Merit & Inflation 4 Mos Ending 4/30/2027**	**Other Adjustments**	**Projected O&M 12 Mos Ending 4/30/2027**
				(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
	Total O&M	**128,438**	**128,438**	**2,697**	**131,136**	**3,147**	**134,283**	**1,074**	**-31,625**	**103,732**
1	Labor	74,738	74,738	1,570	76,308	1,831	78,139	625	-18,402	60,362
2	Material	5,597	5,597	118	5,715	137	5,852	47	-1,378	4,520
3	Contractor	23,210	23,210	487	23,697	569	24,266	194	-5,715	18,745
4	Non-Labor Overheads	100	100	2	103	2	105	1	-25	81
5	Non-Labor Other	24,793	24,793	521	25,314	608	25,921	207	-6,105	20,024

Notes

		2025	2026	2027
*	Annual merit increase			
	Annual merit increase	2.10%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated merit increase	2.10%	2.4%	0.8%
	Annual inflation rates per WP-JCA-51			
	Annual inflation rates	2.10%	2.4%	2.4%
	Number of months in the period	12	12	4
	Pro-rated inflation rate	2.10%	2.4%	0.8%

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21870
Exhibit No.: A-43 (RTB-4)
Page: 3 of 3
Witness: RTBlumenstock
Date: June 2025

Consumers Energy Company
Summary of the Generation O&M Expense
For the Years 2024 through April 2027
($000's)

GENERATION MAJOR MAINTENANCE EXPENSES

Line No.	(a) Description	(b) Historical 12 Months Ended 12/31/2024	(c) Projected Bridge Period 16 Months Ending 04/30/2026	(d) Projected Test Year 12 Months Ending 04/30/2027
	Major Maintenance			
1	Campbell 1&2	$ 903	$ 483	$ -
2	Campbell 3	$ 591	$ 709	$ 279
3	Karn 1&2	$ -	$ -	$ -
4	Karn 3&4	$ 2,027	$ 2,732	$ 1,824
5	Classic 7	$ -	$ 291	$ 218
6	Zeeland Generating Station	$ 4,954	$ 7,063	$ 5,419
7	Jackson Generating Station	$ 5,669	$ 5,712	$ 4,112
8	Covert Generating Stations	$ 6,553	$ 8,681	$ 7,771
9	Ludington	$ 3,314	$ 5,842	$ 4,708
10	Hydros	$ 4,832	$ 7,937	$ 8,374
11	Battery	$ -	$ 412	$ 126
12	Admin & Other	$ -	$ 150	$ 150
13	**TOTAL Major Maintenance**	**$ 28,844**	**$ 40,012**	**$ 32,982**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 13

Kapala Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.
______________________________________/

Case No. U-21090

Volume 7

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
ANNE M. UITVLUGT, ESQ.
IAN F. BURGESS, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

NORMAN J. KAPALA
REVISED DIRECT TESTIMONY

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

Q. What is your formal education experience?

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

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

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

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

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

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

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) Revised	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) Revised	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

Exhibit A-55 (NJK-6) Revised	Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants;
Exhibit A-56 (NJK-7)	Summary of Projected Generation Operations Separation Activity Capital Expenditures;
Exhibit A-57 (NJK-8) Revised	Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032;
Exhibit A-58 (NJK-9)	Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032;
Exhibit A-59 (NJK-10)	Generating Unit Random Outage Rates; and
Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

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

A. Yes.

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-50 (NJK-1) Revised.

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
    - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
    - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
    - Low Pressure Turbine Overhaul ($3,500,000);
    - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
    - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
    - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
    - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
    - Replace CO-O2 Monitors ($1,044,600);
    - Mill Complete Overhauls ($1,235,000);
    - Reheater Sootblower ($1,250,000);
    - Sootblowing Air Upgrade ($1,200,000);
    - Replace Lake Michigan Intake Screens ($1,339,000);
    - Cell Construction and Permitting ($5,482,830); and
    - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
  - SCR Reactor Catalyst Management ($1,866,200);
  - Complete Mill Overhauls ($1,264,800);
  - Replace CO-O2 Monitors ($967,400);
  - Design and Install New Large Particle Ash Screen ($1,485,100);
  - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

  - Distributed Control System and Simulator Upgrade ($1,500,000); and
  - Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and

- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - SCR Reactor Catalyst Management ($1,959,510);
  - Turbine Drain Modifications ($2,535,000);
  - Superheat Terminal Drain Replacement ($3,023,100);
  - Replace Boiler Sidewall Panels ($2,425,000);
  - Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - Secondary Air Heater basket & seal replacement ($1,562,000);
  - Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~Dry Ash Landfill Closure ($1,635,230);~~
  - Cell Construction and Permitting ($5,482,830); and
  - ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;

- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
  - GSU Replacement ($6,485,045);
  - SCR Reactor Catalyst Management ($3,000,000);
  - AQCS Equipment repair/replacement ($1,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
  - Cell Construction and Permitting ($2,000,000); and
  - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

  - Catalyst Management ($1,120,000); and
  - Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~o~~ Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

    - Fuel Handling and Infrastructure Replacements ($1,000,000);
    - AQCS Equipment repair/replacement ($1,000,000); and
    - Two projects totaling $1,500,000 with no individual project which exceeds $500,000;

- 2029: Five projects totaling $2,500,000, which include;
    - AQCS Equipment repair/replacement ($1,000,000); and
    - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
    ~~o~~ Cell Construction and Permitting ($3,500,000);
    - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
    - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
    - SCR Reactor Catalyst Management ($2,000,000); and
    - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
    - SCR Reactor Catalyst Management ($3,000,000);
    - Boiler Component Replacement ($5,000,000);
    - AQCS Equipment repair/replacement ($2,000,000); and
    - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
    - AQCS Equipment repair/replacement ($3,000,000); and
    - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
    - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
    - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
    - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
    - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
    - Campbell 3 Turbine Valve Inspection ($1,200,000); and
    - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
    - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
    - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
    - Boiler Feed Pump Turbine Inspection ($1,680,000); and
    - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
  - Campbell 3 Turbine Overhaul ($7,931,350);
  - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
  - Campbell 3 Periodic Outage Maintenance ($933,100); and
  - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
  - Campbell 3 Turbine Overhaul ($12,000,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
  - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);

   - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
   - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
   - Campbell 3 Turbine Valve Inspection ($1,400,000);
   - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
   - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

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January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
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Generation Operations - Capital - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Karn 1/2 Total	Karn 3/4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	2020	7,176	8,679	10,025	9,268	12,860
2	2021	2,859	4,172	3,493	13,512	19,576
3	2022	2,135	15,416	7,300	5,257	17,125
4	2023	1,124	10,072	7,215	9,472	20,478
5	2024		9,775	9,753	11,252	33,396
6	2025		10,134	2,550	7,800	14,512
7	2026		9,900	3,300	4,420	4,400
8	2027		8,950	4,050	6,845	5,900
9	2028		2,000	3,500	7,394	4,400
10	2029		2,000	3,879	2,500	11,750
11	2030		1,000	2,564	1,050	11,150
12	2031		500	250	250	2,400
13	2032					2,750
14	2033					11,750
15	2034					5,400
16	2035					10,150
17	2036					4,650
18	2037					2,400
19	2038					550
20	2039					
21	Total	$ 13,294	$ 82,598	$ 57,878	$ 79,020	$ 195,597

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Karn 3&4 Early Retirement Case

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Karn 3&4 5/31/2023					**Retire Karn 3 & 4 5/31/2025**			
Line No.	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Ca:	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Ca:	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
1	2020	5,500	-	(3,179)	-	2020	8,679	-	-	-
2	2021	750	-	(3,422)	-	2021	6,012	-	1,840	(667)
3	2022	500	-	(14,916)	(13,675)	2022	2,370	-	(13,046)	(7,204)
4	2023	200	-	(9,872)	(1,790)	2023	1,850	-	(8,222)	(1,290)
5	2024	-	-	(9,775)	-	2024	500	-	(9,275)	-
6	2025	-	-	(10,134)	-	2025	200	-	(9,934)	-
7	2026	-	-	(9,900)	-	2026	-	-	(9,900)	-
8	2027	-	-	(8,950)	-	2027	-	-	(8,950)	-
9	2028	-	-	(2,000)	-	2028	-	-	(2,000)	-
10	2029	-	-	(2,000)	-	2029	-	-	(2,000)	-
11	2030	-	-	(1,000)	-	2030	-	-	(1,000)	-
12	2031	-	-	(500)	-	2031	-	-	(500)	-
13	Total	$ 6,950	$ -	$ (75,648)	$ (15,465)	Total	$ 19,611	$ -	$ (62,987)	$ (9,161)

Note:
1. Cost of removal has not been included.

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Generation Operations - Capital - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Retire Campbell 3 5/31/2025				**Retire Campbell 3 5/31/2032**		
Line No.	Year	Campbell 3 Total	Campbell 3 ariance to Base Cas	Campbell Unit 3 Separation Variance to Base Case	Year	Campbell 3 Total	Campbell 3 ariance to Base Cas	Campbell Unit 3 Separation Variance to Base Case
1	2020	12,860	0	-	2020	12,860	0	-
2	2021	18,397	(1,179)	-	2021	19,576	-	-
3	2022	12,885	(4,240)	-	2022	17,125	-	-
4	2023	8,705	(11,773)	-	2023	20,478	-	-
5	2024	6,044	(27,352)	-	2024	33,396	-	-
6	2025	400	(14,112)	-	2025	14,512	-	-
7	2026	-	(4,400)	-	2026	4,400	-	-
8	2027	-	(5,900)	-	2027	5,900	-	-
9	2028	-	(4,400)	(6,780)	2028	4,400	-	(6,780)
10	2029	-	(11,750)	(14,341)	2029	8,750	(3,000)	(14,341)
11	2030	-	(11,150)	(28,683)	2030	11,150	-	(28,683)
12	2031	-	(2,400)	(14,341)	2031	2,400	-	(14,341)
13	2032	-	(2,750)	-	2032	2,750	-	-
14	2033	-	(11,750)	-	2033	-	(11,750)	-
15	2034	-	(5,400)	-	2034	-	(5,400)	-
16	2035	-	(10,150)	-	2035	-	(10,150)	-
17	2036	-	(4,650)	-	2036	-	(4,650)	-
18	2037	-	(2,400)	-	2037	-	(2,400)	-
19	2038	-	(550)	-	2038	-	(550)	-
20	2039	-	-	-	2039	-	-	-
21	Total	$ 59,291	$ (136,306)	$ (64,146)	Total	$ 157,697	$ (37,900)	$ (64,146)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 1 Early Retirement Cases

Retire Campbell 1 5/31/2024 / **Retire Campbell 1 5/31/2025**

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to Base Case	(e) Campbell 2 Variance to Base Case	(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to Base Case	(j) Campbell 2 Variance to Base Case
1	2020	9,644	9,268	(381)	-	2020	9,989	9,268	(36)	-
2	2021	3,293	13,541	(200)	29	2021	3,293	13,512	(200)	-
3	2022	1,050	5,257	(6,250)	-	2022	3,810	5,257	(3,490)	-
4	2023	800	9,696	(6,415)	224	2023	3,784	9,472	(3,431)	-
5	2024	250	11,252	(9,503)	-	2024	800	11,252	(8,953)	-
6	2025	-	7,800	(2,550)	-	2025	250	7,800	(2,300)	-
7	2026	-	4,420	(3,300)	-	2026	-	4,420	(3,300)	-
8	2027	-	6,845	(4,050)	-	2027	-	6,845	(4,050)	-
9	2028	-	7,394	(3,500)	-	2028	-	7,394	(3,500)	-
10	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
11	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
12	2031	-	250	(250)	-	2031	-	250	(250)	-
13	Total	$ 15,037	$ 79,273	$ (42,840)	$ 253	Total	$ 21,926	$ 79,020	$ (35,951)	$ -

Retire Campbell 1 5/31/2026 / **Retire Campbell 1 5/31/2028**

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to Base Case	(e) Campbell 2 Variance to Base Case	(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to Base Case	(j) Campbell 2 Variance to Base Case
14	2020	9,989	9,268	(36)	-	2020	10,025	9,268	-	-
15	2021	3,293	13,512	(200)	-	2021	3,493	13,512	-	-
16	2022	3,810	5,257	(3,490)	-	2022	7,300	5,257	-	-
17	2023	4,073	9,472	(3,141)	-	2023	7,215	9,472	-	-
18	2024	1,616	11,252	(8,137)	-	2024	9,753	11,252	-	-
19	2025	800	7,800	(1,750)	-	2025	2,550	7,800	-	-
20	2026	250	4,420	(3,050)	-	2026	2,050	4,420	(1,250)	-
21	2027	-	6,845	(4,050)	-	2027	800	6,845	(3,250)	-
22	2028	-	7,394	(3,500)	-	2028	250	7,394	(3,250)	-
23	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
24	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
25	2031	-	250	(250)	-	2031	-	250	(250)	-
26	Total	$ 23,831	$ 79,020	$ (34,046)	$ -	Total	$ 43,436	$ 79,020	$ (14,442)	$ -

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 2 Early Retirement Cases

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2024					**Retire Campbell 2 5/31/2025**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	10,025	8,861	-	(407)	2020	10,025	9,219	-	(49)
2	2021	3,530	11,739	37	(1,773)	2021	3,493	13,271	-	(241)
3	2022	7,300	1,300	-	(3,957)	2022	7,300	5,107	-	(150)
4	2023	7,500	800	285	(8,672)	2023	7,215	3,800	-	(5,672)
5	2024	9,753	250	-	(11,002)	2024	9,753	800	-	(10,452)
6	2025	2,550	-	-	(7,800)	2025	2,550	250	-	(7,550)
7	2026	3,300	-	-	(4,420)	2026	3,300	-	-	(4,420)
8	2027	4,050	-	-	(6,845)	2027	4,050	-	-	(6,845)
9	2028	3,500	-	-	(7,394)	2028	3,500	-	-	(7,394)
10	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
11	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
12	2031	250	-	-	(250)	2031	250	-	-	(250)
13	Total	$ 58,200	$ 22,950	$ 322	$ (56,070)	Total	$ 57,878	$ 32,446	$ -	$ (46,573)

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2026					**Retire Campbell 2 5/31/2028**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	10,025	9,219	-	(49)	2020	10,025	9,268	-	-
15	2021	3,493	13,271	-	(241)	2021	3,493	13,512	-	-
16	2022	7,300	5,107	-	(150)	2022	7,300	5,257	-	-
17	2023	7,215	3,800	-	(5,672)	2023	7,215	9,472	-	-
18	2024	9,753	1,300	-	(9,952)	2024	9,753	11,252	-	-
19	2025	2,550	800	-	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	3,300	250	-	(4,170)	2026	3,300	3,170	-	(1,250)
21	2027	4,050	-	-	(6,845)	2027	4,050	3,706	-	(3,139)
22	2028	3,500	-	-	(7,394)	2028	3,500	250	-	(7,144)
23	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
24	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
25	2031	250	-	-	(250)	2031	250	-	-	(250)
26	Total	$ 57,878	$ 33,746	$ -	$ (45,273)	Total	$ 57,878	$ 60,687	$ -	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2) Revised
Page: 6 of 6
Witness: NJKapala
Date: October 2021

Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2024					**Retire Campbell 1&2 5/31/2025**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	8,861	(381)	(407)	2020	9,989	9,219	(36)	(49)
2	2021	3,293	11,739	(200)	(1,773)	2021	3,293	13,271	(200)	(241)
3	2022	1,050	1,300	(6,250)	(3,957)	2022	3,810	5,107	(3,490)	(150)
4	2023	800	800	(6,415)	(8,672)	2023	3,784	3,800	(3,431)	(5,672)
5	2024	250	250	(9,503)	(11,002)	2024	800	800	(8,953)	(10,452)
6	2025	-	-	(2,550)	(7,800)	2025	250	250	(2,300)	(7,550)
7	2026	-	-	(3,300)	(4,420)	2026	-	-	(3,300)	(4,420)
8	2027	-	-	(4,050)	(6,845)	2027	-	-	(4,050)	(6,845)
9	2028	-	-	(3,500)	(7,394)	2028	-	-	(3,500)	(7,394)
10	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
11	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
12	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
13	Total	$ 15,037	$ 22,950	$ (42,840)	$ (56,070)	Total	$ 21,926	$ 32,446	$ (35,951)	$ (46,573)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2026					**Retire Campbell 1&2 5/31/2028**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,219	(36)	(49)	2020	10,025	9,268	-	-
15	2021	3,293	13,271	(200)	(241)	2021	3,493	13,512	-	-
16	2022	3,810	5,107	(3,490)	(150)	2022	7,300	5,257	-	-
17	2023	4,073	3,800	(3,141)	(5,672)	2023	7,215	9,472	-	-
18	2024	1,616	1,300	(8,137)	(9,952)	2024	9,753	11,252	-	-
19	2025	800	800	(1,750)	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	250	250	(3,050)	(4,170)	2026	2,050	3,170	(1,250)	(1,250)
21	2027	-	-	(4,050)	(6,845)	2027	800	3,706	(3,250)	(3,139)
22	2028	-	-	(3,500)	(7,394)	2028	250	250	(3,250)	(7,144)
23	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
24	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
25	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
26	Total	$ 23,831	$ 33,746	$ (34,046)	$ (45,273)	Total	$ 43,436	$ 60,687	$ (14,442)	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 14

Hoffman 2024 Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for reconciliation of its power supply recovery plan (Case No. U-21257) for the twelve months ended December 31st, 2023.

Case No. U-21258
Volume 2

* PUBLIC *

_________________________________/

REVISED

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Thursday, March 20, 2025, at 9:07 AM.

APPEARANCES:

EVAN B. KEIMACH, ESQ.
Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201

On behalf of Consumers Energy Company

THOMAS J. WATERS, ESQ.
The Running Wise Law Firm
1501 Cass Street, Suite D
Traverse City, Michigan 49684-4157

On Behalf of Biomass Merchant Plants

(Continued)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for reconciliation of its power supply cost	)	Case No. U-21258
recovery plan (Case No. U-21257)	)	
for the 12 months ended December 31, 2023.	)	
______________________________________	)	

REVISED DIRECT TESTIMONY

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2024

Q. Please state your name and business address.

A. My name is Nathan J. Hoffman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director – Fossil Generation.

Q. Please describe your educational background.

A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from Ferris State University. In 2017, I received a Master of Business Administration with a concentration in Advanced Management Tools and Concepts from Ferris State University.

Q. Please describe your business experience.

A. In 2005, I joined Consumers Energy at the J.H. Campbell ("Campbell") Generating Complex and progressed through positions from Engineering Technical Analyst to the Executive Director – Fossil Generation. In my various roles at Consumers Energy, I served as a subject matter expert for boiler and piping systems and was an embedded engineering resource in the Operations Department responsible for monitoring plant performance and troubleshooting. I also planned and executed outages to ensure that they were performed in a prudent and expeditious manner, as well as managed the site maintenance organization tasked with maintaining the plant systems and equipment. As the Executive Director – Fossil Generation, I have overall responsibility for the safe and excellent operations of the Fossil Generation Fleet. In this role, I also manage the overall Operating and Maintenance and Capital budgets, develop site specific staffing plans, develop strategies to meet Company objectives, and instill a culture of continuous improvement. I further oversee the performance of the Site's Operations, Maintenance, Fuel Handling, and Environmental and Technical Services departments.

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

A. Yes, I provided testimony in the Company's 2023 Power Supply Cost Recovery ("PSCR") Plan, Case No. U-21257; the Company's 2024 PSCR Plan, Case No. U-21423; and the Company's 2022 PSCR Reconciliation, Case No. U-21049.

<u>Purpose of Direct Testimony</u>

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

A. The purpose of my direct testimony is to:

- Describe the reasonableness and prudence of certain outages experienced in 2023 at the Company's fossil-fueled electric generating units and the River Hydroelectric generating units ("River Hydros");
- Describe the outages experienced in 2023 at the Company's Ludington Pumped Storage Plant ("Ludington"), including the outages at Ludington resulting from faulty work performed by Toshiba America Energy Systems Corporation ("TAES"), and the associated costs, which the Company has recorded to the regulatory asset approved by the Commission in Case No. U-21310;
- Explain the expense associated with emission allowances for oxides of nitrogen ("NO_x") and Sulfur Dioxide ("SO_2");
- Explain the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon;
- Explain the 2023 performance of the Company's owned wind assets; and
- Explain the treatment of the replacement power costs associated with Ludington unit outages resulting from the defective work performed by TAES.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-10 (NJH-1)	Event Summary Report, January 2023 to December 2023;

Exhibit A-11 (NJH-2)	Event Identification – Outages;
Exhibit A-12 (NJH-3)	Periodic Outage Reports;
Exhibit A-13 (NJH-4)	2023 Fossil and Pumped Storage Outages Occurring for Twenty-Eight Days or More;
Exhibit A-14 (NJH-5)	Generation Performance Statistics (January 1, 2023 to December 31, 2023);
Exhibit A-15 (NJH-6)	Comparison of Consumers Energy and GADS Averages for Similar Units Equivalent Availability;
Exhibit A-16 (NJH-7)	2023 Base Load Generation Power Plant Cost Efficiency;
Exhibit A-17 (NJH-8)	Chemical Reagent Expense (January 1, 2023 to December 31, 2023);
Exhibit A-18 (NJH-9)	2023 Wind Asset Performance Data; and
Exhibit A-19 (NJH-10) Revised	2023 Ludington Outages.

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

A. Yes.

<u>2023 Outages</u>

Q. Have you provided a listing of all 2023 outages?

A. Yes. The Event Summary Report, Exhibit A-10 (NJH-1), lists all unit outages and trips. The report shows 35 events on the coal units, 124 on the Ludington Units, 64 on the Zeeland Combined Cycle Plant ("Zeeland CC") (Units 3, 4, and 5), Covert Gas Plant ("Covert"), and Jackson Gas Plant ("Jackson"), 37 on D.E. Karn ("Karn") Units 3 and 4, 22 on the Zeeland Simple Cycle ("Zeeland SC") (Units 1 and 2), and 142 on the River Hydro units. The total number of outage events for the fleet was 424 in 2023, 99 fewer than in 2022.

Exhibit A-10 (NJH-1) provides a description of each event, including the event start time, event end time, cause code,[1] duration in equivalent hours, and equivalent MWh. The equivalent MWh calculation assumes that the units would have operated at 100% capacity factor.

Q. Has the Company also calculated the lost generation for the Ludington Units in accordance with the Settlement Agreement approved in the Commission's June 28, 2018 Order in Case No. U-17918-R?

A. Yes. Company witness Joshua W. Hahn provides the economic MWh loss calculations for the Ludington Units assuming they were operating and dispatchable. These calculations are presented in Exhibit A-9 (JWH-3).

Q. Would you please define the words "outage," "trip," and "event"?

A. A unit "outage" on a base-load unit is defined as the period from when the circuit breaker opens, separating the unit from the electric system, to when it closes, tying the unit to the electric system and making it available for dispatch, and the unit is not in economic reserve status. A unit "outage" on a cycling or peaking unit is defined as the period from when the Company's Electric Supply Operations Department releases a unit, making it unavailable, to when the plant reports to Electric Supply Operations that the unit is available for service. For the purposes of these definitions, the coal and river hydro units are considered base-load units, and the Zeeland, Jackson, Covert, and Karn Units 3 and 4 are all considered cycling units. Zeeland Units 1 and 2 are considered peakers. Base load generation refers to the minimum amount of electric power required to be delivered to customers over a

[1] Cause codes used are taken from the Data Reporting Instructions of the North American Electric Reliability Corporation ("NERC") Generating Availability Data System. Explanations for the cause codes can be found at: Data Reporting Instructions (nerc.com)

given period of time at a steady rate. Base load generating units are units which are typically operated to serve customer loads on an around-the-clock basis.

A "trip" is a unit outage that begins when protective devices automatically separate a unit from the electric system, or the operator initiates a manual and immediate separation. This is in contrast to the normal controlled shutdown process where operators may spend several hours slowly reducing pressure and load before separating the unit from the system.

An "event" is a one-line entry on the Event Summary Report. Each line on the Report contains an outage "event." The outage event classification is divided into eight distinct event types: (i) Planned Outage; (ii) Maintenance Outage; (iii) Planned Outage Extension; (iv) Maintenance Outage Extension; (v) Startup Failure; (vi) Unplanned (Forced) Outage-Immediate; (vii) Unplanned (Forced) Outage–Delayed; and (viii) Unplanned (Forced) Outage-Postponed. Exhibit A-11 (NJH-2) explains the different types of outages shown on Exhibit A-10 (NJH-1).

Q. Have you documented outage occurrences in more detail?

A. Yes. In addition to documenting all of the 2023 outages reported on page 3 of this testimony and reflected in Exhibit A-10 (NJH-1), outage information sheets were also prepared for generating units that had lower availability averages than those shown in Generating Availability Data System ("GADS") data discussed later in my direct testimony. The information sheets are provided as Exhibit A-12 (NJH-3). Each sheet contains the same statistical data found on Exhibit A-10 (NJH-1), as well as: (i) an expanded description of the event; (ii) a cause of the event; (iii) the work that was done to correct the root cause for forced outages or the work that was performed during maintenance and periodic outages; (iv) other work, if any, that was performed; (v) a description of work that extended the outage, if any extension occurred; and (vi) why that work was performed.

Additionally, the Company prepared a Periodic Outage, Maintenance Outage, or Forced Outage Information sheet for each of the events lasting 28 days or more on the fossil, pumped storage, peaking, and River Hydro units shown on Exhibit A-10 (NJH-1).

Q. Before discussing specific outages, do you have any general comments about outages in the Company's generation fleet?

A. Yes, particularly concerning the Company's older units. Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist, and while I outline the incredible efforts taken to repair the SUBFP, it remains offline.

<u>Fossil, Cycling, and Pumped Storage Outages Planned for 28 Days or More</u>

Q. In Case No. U-21257, how many outages were planned for 28 days or more?

A. My direct testimony and Exhibit A-11 (NJH-1) identified twelve such outages.

Q. Were all twelve outages completed during the plan year?

A. No. Only eight of the planned outages were completed during the plan year; the planned outages for Campbell Unit 1, Karn Unit 2, Karn Unit 3, and Karn Unit 4 were not performed.

Q. Why wasn't the planned outage at Campbell Unit 1 performed?

A. The Campbell Unit 1 outage was scheduled to begin on October 13, 2023 and last for 31 days. However, the unit had been placed into economic reserve status on February 19, 2023 and subsequently began a maintenance outage on March 7, 2023. The maintenance outage lasted for 14 days, ending on March 21, 2023. During this timeframe, all priority work scope that was scheduled for the fall outage was completed, obviating the need for the planned outage scheduled to begin on October 13, 2023.

Q. Why wasn't the planned outage at Karn Unit 2 performed?

A. The outage at Karn Unit 2 was scheduled to begin May 1, 2023 and was projected to last for 30 days – concluding May 31, 2023. The outage was scheduled to perform preparation activities for unit cessation on May 31, 2023. However, due to the need to burn down the remaining coal, the outage was not taken as planned. A maintenance outage was taken for 11 days in early May to perform visual inspections of backpass, pulse jet fabric filters, and the selective catalytic reduction vessels to quantify the ash accumulation needing to be abated upon cessation of operations.

Q. Why weren't the planned outages for Karn Units 3 and 4 performed?

A. The Karn Unit 3 and 4 outages were not performed due to availability of materials for the major work that was planned. Due to the uncertainty of the retirement of Karn Units 3 and 4 as proposed in the Company's 2021 Integrated Resource Plan ("IRP"), the preparation for these outages was not complete, including material delivery. As such the planned work was deferred to 2024.

Q. Did the Company conduct additional outages of 28 days or more in 2023?

A. Yes. In addition to the eight planned outages which lasted longer than 28 days, the Company conducted two additional outages for a total of ten outages that lasted 28 days or more. The additional outages included Campbell Unit 2 and Karn Unit 3. All ten outages are identified in Exhibit A-13 (NJH-4).

Q. Has your review of the outages listed in Exhibit A-13 (NJH-4) led you to a conclusion concerning these outages?

A. Yes. I have concluded that all of the outages listed in Exhibit A-13 (NJH-4) were carefully planned, prudently managed, and free of negligence on the part of Consumers Energy as to either causation or extension of outage time. Below is a brief summary of each of the outages listed in Exhibit A-13 (NJH-4).

<u>Campbell Unit 2</u>

The Campbell Unit 2 outage began on August 4, 2023 due to a tube leak in the hydraulic coupling circuit oil cooler. The tube leak resulted in water intrusion into the oil system, thereby forcing the unit to be removed from service. Subsequently, on August 10, 2023, the SUBFP experienced a thrust event causing damage to the internal flow element, thrust bearing, and drive coupling. The unit was out of service for the remainder of the year, a total of 149 days. A detailed discussion of the extended outage is provided later in this direct testimony.

<u>Campbell Unit 3</u>

The outage at Campbell Unit 3 was scheduled to begin April 1, 2023 and was projected to last for 42 days – concluding May 13, 2023. The outage began on March 31, 2023 and lasted 40 days, ending on May 10, 2023. The outage was necessary for the planned replacement of a catalyst layer in the Selective Catalytic Reduction ("SCR") vessel and repair of a suspected boiler waterwall leak. In addition, performance of NERC testing was required following substation modifications necessary to support site decommissioning.

Karn Unit 3

The outage at Karn Unit 3 was scheduled to begin March 5, 2023 and was projected to last for 41 days – concluding April 15, 2023. The outage began on March 5, 2023 and lasted for 41 days, ending on April 15, 2023. The outage was necessary for the performance of cooling tower repairs. In addition, the Company conducted NERC relay testing, replaced substation generator circuit breaker controls, performed miscellaneous balance of plant mechanical repairs, and removed three cooling fan assemblies for overhaul.

Karn Unit 3

The outage at Karn Unit 3 began on May 31, 2023 and lasted 102 days – concluding September 10, 2023. The outage was caused by the failure of one of the J-strap connectors which connects the exciter rotor to its windings. The work required to restore the unit to service included disassembly of the exciter for shipment to a vendor for inspection and rewind of the rotor windings. A detailed discussion of the extended outage is provided later in this direct testimony.

Ludington Unit 5

The outage at Ludington Unit 5 was scheduled to begin May 15, 2023 and was projected to last for 40 days – concluding June 24, 2023. The outage began on May 15, 2023 and lasted for 46 days, ending on June 30, 2023. The outage was necessary for the annual periodic outage warranty inspections, main transformer bank #3 inspections, turbine lube oil coolers maintenance, and wicket gate thrust collar and seal inspections and repairs. The outage was extended due to failure of the emergency intake gate hoist control. A failed silicon-controlled rectifier and power resistor for the DC control led to this failure and the replacement of those components rectified the issue.

Ludington Unit 6

The outage at Ludington Unit 5 was scheduled to begin May 15, 2023 and was projected to last for 40 days – concluding June 24, 2023. The outage began on May 15, 2023 and lasted for 39 days, ending on June 23, 2023. The outage was necessary for the annual periodic outage warranty inspections, main transformer bank #3 inspections, turbine lube oil coolers maintenance, and wicket gate thrust collar and seal inspections and repairs.

Zeeland Unit 1

The Zeeland Unit 1 outage began on December 27, 2022 and lasted for a total of 100 days, 96 days in 2023, ending on April 7, 2023. The outage was necessary due to the need for the Company to move the leased generator step-up ("GSU") transformer from Zeeland Unit 1 to Zeeland Unit 5. The basis for the decision to move the leased GSU transformer to Zeeland Unit 5 is the increased economics of Zeeland Unit 5 due to its operation as a combined cycle unit versus that of Zeeland Unit 1 which is a single cycle unit. A detailed discussion of the extended outage is provided later in this direct testimony.

Zeeland Unit 3

The outage at Zeeland Unit 3 was scheduled to begin September 22, 2023 and was projected to last for 57 days – concluding November 18, 2023. The outage began on November 4, 2023 and lasted for 40 days, ending on December 14, 2023. The outage was necessary for the planned inspection and repair of the unit pursuant to requirements of the Long-Term Service Agreement ("LTSA") based upon unit operating hours.

Zeeland Unit 4

The outage at Zeeland Unit 4 was scheduled to begin September 22, 2023 and was projected to last for 57 days – concluding November 18, 2023. The outage began on

November 4, 2023 and lasted for 39 days, ending on December 13, 2023. The outage was necessary for the planned inspection and repair of the unit pursuant to requirements of the LTSA based upon unit operating hours.

Zeeland Unit 5

The outage at Zeeland Unit 5 was scheduled to begin September 22, 2023 and was projected to last for 57 days – concluding November 18, 2023. The outage began on November 4, 2023 and lasted for 39 days, ending on December 13, 2023. The outage was necessary for the planned inspection and repair of the unit pursuant to requirements of the LTSA based upon unit operating hours.

Q. Did the Company conduct any outages that exceeded 90 days in duration?

A. Yes. The Company conducted three outages during 2023 that exceeded 90 days in duration. The first of these was the Zeeland Unit 1 outage which began in December 2022 and lasted for 96 days during 2023. The additional outages that exceeded 90 days in duration were the Campbell Unit 2 outage which lasted for 149 days during 2023 and the Karn Unit 3 outage which lasted for 102 days during 2023.

Q. Why did the Zeeland Unit 1 outage exceed 90 days?

A. As previously discussed in this direct testimony, the Zeeland Unit 1 outage began on December 27, 2022, upon the economic changeout of the spare GSU (leased) transformer from Zeeland Unit 1 to Zeeland Unit 5. The leased GSU transformer was installed on Zeeland Unit 1 in May 2022, subsequent to the failure of the originally-installed GSU transformer on Zeeland Unit 1. The outage lasted for a total of 100 days, 96 days in 2023, and the unit was returned to service on April 7, 2023, upon return of the repaired GSU transformer.

Q. Why was the original GSU transformer for Zeeland Unit 1 removed?

A. The original equipment manufacturer recommended that the original transformer not be re-energized due to elevated and rising acetylene gas concentrations measured in the transformer. High concentrations of acetylene in a transformer are an indication of defects that may induce transformer failure. As a result, the original transformer was removed from service after efforts to identify the cause of elevated acetylene indicated evidence of possible low voltage winding damage.

Q. Does the Company routinely monitor the condition of its GSU transformers?

A. Yes. Specifically, at Zeeland, the Company monitors all GSU transformers with continuous gas analyzers. In addition, oil testing is performed on an annual basis and routine transformer maintenance is regularly performed to help prevent unplanned failures. The Company reasonably and prudently monitored and maintained its transformer and did not cause the transformer to fail nor cause the outage extension. The Company's monitoring efforts allowed it to identify imminent failure of the GSU transformer for Zeeland Unit 5 and take actions to swap the leased GSU transformer installed on Zeeland Unit 1 and install it on Zeeland Unit 5 in order to minimize customer power costs.

Q. Please discuss the condition of Zeeland Unit 5?

A. On August 24, 2022, an alarm for the Unit 5 GSU Transformer on rising levels of Methane was noted by a plant operator. An investigation of the dissolved gas analysis trends revealed that there was an exponential increase in dissolved gases starting around August 10, 2022. The rate of rise continued to increase until the unit went into a planned outage on September 17, 2022. During that period Hydrogen increased from 36 to 135 ppm, Methane 81 to 218 ppm, Ethane 43 to 90 ppm, and Ethylene 36 to 157 ppm. The gassing ratios indicated a thermal fault 300 to 700 C and possible carbonization of paper, per IEEE C57.104-2019 interpretation. Due to the alarming rate of rise, the Company performed an unplanned internal inspection of the transformer during the fall 2022 Phase 2 outage. The internal inspection and testing revealed:

- The Low Voltage (“LV”) bushings had effectively failed in service;
- The transformer core ground connection was missing since commissioning in 2001;
- The LV connections internal to the transformer had indications of severe heating; and
- The IsoPhase bus shielding duct was in contact with the LV bushing housings on all three phases potentially creating a local circulating current and heat.

As result of the findings, the following corrective actions were taken:

- The transformer was drained;
- The LV bushings were replaced with surplus bushings. The “new” bushings were not a “like-for like” replacement and several modifications were made to the bus bar connections to adapt them to the existing configuration;
- The core ground was terminated;
- IsoPhase bus was isolated from the LV bushing housings with an air gap; and
- The transformer was then filled with oil.
- Electrical tests on the transformer were repeated to ensure equipment functionality. The tests indicated that the LV winding insulation had moderately aged, but was acceptable to put the transformer back in service.
- The transformer was returned to service on October 11, 2022.

Q. What were the results of the corrective actions?

A. The corrective actions had little effect on the rate of gassing after the transformer was returned to service. The unit was removed from service on December 17, 2022 and shipped to Hitachi (Stoney Creek) for overhaul and a temporary mobile GSU was installed in place, to keep Phase 2 available for customers.

Q. Why did the Karn Unit 3 outage exceed 90 days?

A. As previously discussed in this direct testimony, the outage was unplanned and was a result of failure of one of the j-strap connectors which led to a failure to provide proper excitation to the generator. The j-strap connectors are used to provide flexibility as the exciter heats up under load.

Q. When was the exciter last inspected for condition?

A. The exciter was last electrically tested during the 2022 outage with no indication of pending failure. The j-straps are not able to be visually inspected without removal of the rotor's end caps, an activity that can only be performed during a tear down in a vendor's shop.

Q. What action did the Company take to resolve the exciter failure?

A. As a result of the failure, the exciter was disassembled and shipped to a vendor facility for inspection and repair of the rotor windings. The Company has reasonably and prudently inspected the exciter during the previous outage and did not cause the exciter to fail. The Company's actions did not extend the outage in any manner.

Q. Why did the Campbell Unit 2 outage exceed 90 days?

A. As previously discussed in this direct testimony, the Campbell Unit 2 outage began on August 4, 2023 because of a tube leak in the hydraulic coupling circuit oil cooler which resulted in water intrusion into the oil system, thereby forcing the unit to be removed from service.

Q. What work was performed to address the tube leak and what was the root cause of the failure?

A. The tube leak was repaired by plugging the tube and water was removed from the oil system by vacuum dehydrating the oil. The mode of failure for the tube leak was not determined as the tube bundle was not pulled due to short plant life remaining and the fact that no spare tube bundle was available. During post-maintenance testing on August 10, 2023, the SUBFP experienced a thrust event which resulted in damage to the SUBFP internal flow element, thrust bearing, and drive coupling.

Q. What was the root cause of the SUBFP failure?

A. During testing, the SUBFP was unable to generate sufficient pressure and mass flow rate to allow for unit escalation. This resulted in damage to the internal flow element, thrust bearing, and drive coupling. This damage was a result of operational contact between the internal flow element and the pump housing that occurred during the thrust event. The cause of the failure was the thrust event, and the cause of that event is still under investigation.

Q. What work was performed to restore the SUBFP?

A. Following the thrust event, the SUBFP was disassembled and rebuilt. An exact replacement for the drive coupling was not readily available, so the SUBFP was rebuilt with a replacement drive coupling. An identical replacement coupling had a 33-week lead time, and the Company made a decision to get the unit back on-line with a replacement drive coupling. On September 29, 2023, subsequent to the SUBFP rebuild, post maintenance testing was performed which resulted in unacceptably high vibration levels;

the SUBFP experienced high radial vibrations during start up on both the inboard and outboard bearings. As such, the SUBFP was deemed unsafe to operate.

Q. What work was performed to resolve the high vibration levels for the SUBFP?

A. The SUBFP was again disassembled and inspected. While still under investigation, the root cause of the high vibration was assessed to be related to replacement of the drive coupling which is approximately 67 pounds heavier than the original. Additional repair efforts included performance of high-speed balance with no success, inspection of the structural frame and housing of the SUBFP for damage that could cause a shift in the natural operating frequency of the SUBFP with no findings, and installation of dynamic vibration absorbers on both the inboard and outboard bearings to shift the structural natural frequency away from the pump operating frequency. While this last effort resulted in an improvement in radial vibration, the improvement did not bring the vibration within acceptable levels, and vibration anomalies were transmitted to the pump motor placing that component at risk of failure.

Q. What additional work is the Company performing to resolve the high vibration levels for the SUBFP?

A. The Company has been performing detailed modeling of the pump/motor/gearbox assembly in order to select and/or design new coupling options. Detailed analysis by industry experts (HydroAire) point to the source of the vibrations related to the change in rotational inertia caused by the change in coupling mass. Unfortunately, none of the Company's efforts had yielded positive results through year-end 2023 and the unit was out of service for the remainder of the year, a total of 149 days.

The Company rigorously investigated, evaluated, and implemented alternatives to restore the SUBFP to service, and continues to do so. The unavailability of an identical drive coupling (lead time of 33 weeks) led the Company to pursue reasonable alternatives to restore Campbell Unit 2 to service. The Company did not cause the failure of the SUBFP, nor did its actions extend the outage, rather it managed the SUBFP restoration activities in a reasonable, prudent, and responsible manner throughout the 2023 outage duration.

Q. Have you reviewed the peaker and hydro unit outages?

A. Yes. I reviewed the events for each peaker and hydro unit shown on the Event Summary Report, Exhibit A-10 (NJH-1). As previously discussed, Zeeland Unit 1 was the only peaker outage that lasted longer than 28 days in 2023.

River hydro outages greater than 28 days are summarized in the table below:

Line No.	Hydro Unit	Actual Days in 2023	Event Number(s)
1	CROTON 1	271	1
2	CROTON 2	271	1
3	CROTON 4	35	6
4	FIVE CHANNELS 1	46	6
5	FIVE CHANNELS 2	112	3
6	HARDY 2	107	3, 5
7	HODENPYL 1	151	4
8	MIO 2	59	2
9	MIO 2	122	4, 5
10	ROGERS 3	210	1
11	ROGERS 4	210	1
12	WEBBER 1	53	1, 2
13	WEBBER 2	110	3, 4

My review of these events and the additional information provided on Exhibit A-12 (NJH-3) leads me to conclude that those outages were conducted in a prudent manner.

Outages with a Duration of Fewer Than 28 Days

Q. How many periodic outages less than 28 days but greater than one day in length occurred on the fossil and Ludington Units in 2023?

A. As shown on Exhibit A-10 (NJH-1), 34 short periodic (planned) outages occurred on the fossil and Ludington Units in 2023.

Q. What was the purpose of these periodic outages?

A. In general, the purpose of these outages was to perform preventative maintenance activities on equipment that has been assessed as being non-functional or having gone more than one to two years without preventative or corrective maintenance.

Availability

Q. Please discuss the Company's 2023 generation unit availability.

A. The Company's 2023 generation unit availability data is shown on Exhibit A-14 (NJH-5). The Company's Total Fossil MWh availability slightly decreased from 74.76% in 2022 (see Case No. U-21049, Exhibit A-13 (NJH-5), line 11, column (c)) to 74.58% in 2023 (see Exhibit A-14 (NJH-5), line 12, column (c)), due to decreases in MWh availability at Campbell Units 2 and 3, Karn Unit 2, and the Zeeland combined cycle units. The lower MWh availability at the aforementioned units was offset by the increased MWh availability at Campbell Unit 1 and the addition of the Covert units to the generation resource mix. The MWh availability at Campbell Unit 2 was lower due to an extended outage as discussed earlier in this direct testimony, the MWh availability at Campbell Unit 3 was lower due to several forced outages due to boiler and superheat tube leaks, the MWh availability at Karn Unit 2 was lower due to a forced outage to repair boiler leaks and a maintenance outage to perform pre-retirement cessation activities, and the MWh availability for the Zeeland combined cycle units was lower due to the removal of the GSU transformer for Zeeland Unit 5 and its replacement with the leased GSU transformer from Zeeland Unit 1. Despite the slight decrease in MWh availability for these generating units, the Company provided customer benefit in 2023. The Company quantifies this customer benefit through Net Energy Value ("NEV"). At a high level, the NEV of a generating unit is the difference between the market value of the energy produced and the cost of producing and supplying that energy. The Company's estimated 2023 NEV was $225.7 million[2] as compared to the 2022 amount of $700.7 million, including the Company's owned wind assets, an amount which is directly attributable to MWh availability.

The Company's 2023 base load fossil MWh availability decreased from 71.20% in 2022 (see MPSC Case No. U-21049, Exhibit A-13 (NJH-5), line 12, column (c)) to 63.99% in 2023 (see Exhibit A-14 (NJH-5), line 13, column (c)), due to decreases in MWh availability at Campbell Units 2 and 3, and Karn Unit 2. The primary cause of the drop in the Company's 2023 base load fossil MWh availability was the extended outage at Campbell Unit 2, as previously discussed in this direct testimony, dropping the Campbell Unit 2 MWh availability from 63.80% in 2022 to 38.70% in 2023.

<u>Comparison to GADS Data</u>

Q. What is GADS?

A. GADS is the Generator Availability Data System. NERC's GADS maintains operating histories for more than 5,000 generating units in North America. GADS is recognized as a valuable source of reliability information for total unit and major equipment groups. GADS contains information about the performance of electric generating equipment and

[2] The NEV calculation is based upon data pulled from PCI P&L actuals on January 16, 2024. The reduction in NEV from 2022 to 2023 was due to lower market prices in 2023 versus market prices in 2022.

provides assistance to those researching information on power plant outages and supports equipment availability analyses. GADS is a mandatory industry program for conventional generating units 20 MW and larger.

Q. Did you compare the availability of the Company's base load fossil units to GADS data?

A. Yes. I compared the availability of the Company's base load fossil units to both the 2022 and 2018 through 2022 GADS data for comparable sized and fueled units. The results are shown on my Exhibit A-15 (NJH-6). The availability of Campbell Unit 3 was higher than the five-year GADS data and the availability of Karn Unit 2 was higher than the one-year GADs data. The availability of Campbell Unit 2, Campbell Unit 3, Karn Unit 1, and Karn Unit 2 were below both the one-year and five-year comparisons.

Q. Please explain the outages that contributed to lower-than-average availability on a MWh basis.

A. Campbell Unit 2 experienced a total of eleven outages during 2023: three maintenance, and eight unplanned. The maintenance outages were taken for boiler tube leak repair, reheater tube leak repair, ash pit trough repair, and turbine overspeed testing. The eight unplanned outages resulted from a forced draft fan trip, a loss of auxiliary steam/steam seals, a circuit oil cooler leak, and SUBFP failures.

Campbell Unit 3 experienced a total of seven outages during 2023: one planned, two maintenance, and four unplanned. The planned outage was for replacement of a layer of catalyst in the SCR vessel and repair of a suspected boiler waterwall leak. The maintenance outages were for performance of the turbine safety required overspeed trip test and resolution of #2 turbine bearing vibration issues. The four unplanned outages resulted from a drum level swing resulting in hot restart, required boiler leak repairs, superheat tube leak repairs, and drum level swings after south side mills tripped due to a breaker issue.

Karn Unit 1 experienced five outages during 2023: all unplanned outages. The five unplanned outages were taken for coal leaks due to excessive pyrites, south upper intercept valve stuck open, valve failure on the boiler circulating water pump, a faulty feedwater control valve, and poor fuel quality/SO2 emission limited.

Karn Unit 2 experienced two outages during 2023: one maintenance outage and one unplanned outage. The maintenance outage was taken to perform pre-retirement cessation activities. The unplanned outage was for the repair of a boiler leak.

Q. Did you review all of the outages shown on Exhibit A-10 (NJH-1)?

A. Yes. I reviewed all the base load fossil and pumped storage outages that lasted longer than 24 hours.

Q. In your opinion, did Consumers Energy act in a reasonable and prudent manner in connection with the outages you reviewed on Exhibit A-10 (NJH-1)?

A. Yes.

<u>NO_x Allowance Expenses</u>

Q. Did Consumers Energy forecast NO_x expenses in the 2023 PSCR Plan case?

A. No. Consumers Energy did not forecast NO_x expenses in the 2023 PSCR Plan case because Selective Catalytic Reductions ("SCRs") were installed and have significantly reduced NO_x emissions and offset the need to purchase allowances. The SCRs were installed to comply with the Clean Air Interstate Rule ("CAIR"), which was replaced by the Cross-State Air Pollution Rule ("CSAPR"). CSAPR is a cap and trade rule much like

CAIR. CSAPR governs the emission of SO_2 and NO_x from fossil-fueled electric generating units through the use of an allowance based "cap and trade" program. Under CSAPR, NO_x is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or seasonal) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO_2 is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR took effect on January 1, 2015 and Phase II became effective on January 1, 2017. In 2023, no allowance purchases were required for either the annual or seasonal requirements and there were no expenses associated with the allowances allocated by the Michigan Department of Environment, Great Lakes, and Energy.

Q. Did Consumers Energy receive revenue credits in 2023 related to the sale of NO_x allowances?

A. No. The Company did not sell NOx emission allowances in 2023. As such, Company witness Leanna E. Feazel's Exhibit A-5 (LEF-1) Revised does not reflect any expense or revenue credits for NOx emission allowances.

SO_2 Allowance Expenses

Q. Did Consumers Energy incur expenses or receive revenue credits in 2023 related to the SO_2 Allowance Program?

A. Yes. Although the Company did not sell SO_2 emission allowances out of its inventory in 2023, it did receive revenue for a portion ($60) of the Company-allocated SO_2 emission allowances during the annual US Environmental Protection Agency auction.

Q. Are the actual expenses and credits for SO_2 contained in Consumers Energy's 2023 Reconciliation?

A. Yes. Company witness Feazel includes the actual SO_2 expenses and credits in Exhibit A-5 (LEF-1) Revised, line 20.

__Urea Expenses__

Q. What was Consumers Energy's estimate of urea expenses for the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of urea for 2023 to be $4.145 million as reflected on Exhibit A-17 (NJH-8), line 8, column (b), based on projected generation and SCR operations at the Campbell Complex for Campbell Units 2 and 3.

Q. What were the actual urea expenses?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (c), actual urea expense for 2023 was $2.070 million, $2.075 million lower than projected.

Q. Why were actual urea expenses lower than projected?

A. Urea expenses were lower than forecast as a result of lower than projected urea prices as well as lower than projected generation. Urea prices are commodity based and are tied to natural gas prices which experienced significant increases during 2022 but dropped back down in 2023. The forecasted urea price was $832/ton whereas the actual urea cost came in at only $563/ton. The extended outage at Campbell Unit 2 as well as the lower availability at Campbell Unit 3 contributed to the remaining cost decrease.

<u>Aqueous Ammonia</u>

Q. What was Consumers Energy's estimate of aqueous ammonia for the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of aqueous ammonia for 2023 to be $0.799 million as reflected on Exhibit A-17 (NJH-8), line 8, column (d), based on projected generation and SCR operations at Karn Units 1 and 2 and Zeeland Combined Cycle.

Q. What was the actual aqueous ammonia expense?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (e), actual aqueous ammonia expense for 2023 was $1.449 million, $0.650 million higher than projected.

Q. Why were actual aqueous ammonia expenses higher than projected?

A. Total actual aqueous ammonia expense for 2023 was higher due to the addition of Covert to the Company's fleet on June 1, 2023. Aqueous ammonia expenses for Karn Units 1 and 2 were slightly higher than forecast despite the fact that total generation was below that amount projected in the 2023 PSCR Plan, Case No. U-21257. The actual unit cost of aqueous ammonia for Karn Units 1 and 2 was approximately 5% higher than the average unit cost projected in the 2023 PSCR Plan, Case No. U-21257. In addition, with the shutdown of Karn Units 1 and 2 on May 31, 2023, not all of the aqueous ammonia delivered to the Karn site was utilized at the site; the unused quantity was utilized at Covert.

The aqueous ammonia expense for Zeeland was lower than projected due to the fact that the actual unit cost was almost 26% below the projected unit cost. In addition, the capacity factor for the Zeeland combined cycle units was lower than projected.

The aqueous ammonia expense for Covert was higher than projected as the projected aqueous ammonia expense was not reflected in the Company's 2023 PSCR Plan, Case No. U-21257. The addition of Covert to the Company's generation fleet was approved in the MPSC's June 23, 2022 Order in the Company's 2021 IRP, Case No. U-21090.

Lime

Q. What was Consumers Energy's estimate of lime expense in the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of lime for 2023 to be $8.205 million as reflected on Exhibit A-17 (NJH-8), line 8, column (f), based on projected generation and Spray Dry Absorber ("SDA") and Dry Sorbent Injection ("DSI") operations at the Karn and Campbell plants.

Q. What were the total actual lime expenses?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (g), actual lime expense for 2023 was $7.761 million, $0.444 million lower than projected. The Company consumes hydrated lime at Campbell Units 1 and 2 and consumes pebble lime at Campbell Unit 3 and Karn Units 1 and 2. The hydrated lime expense at Campbell Units 1 and 2 was 6.7% or $0.295 million above forecast and the pebble lime expense at Campbell Unit 3 and Karn Units 1 and 2 was 19.6% or $0.740 million below forecast.

Q. Why were the actual hydrated lime expenses higher than projected?

A. 2023 hydrated lime expenses were higher than projected for Campbell Units 1 and 2, primarily due to the quality of the coal delivered and consumed at Campbell Units 1 and 2, despite the lower than projected generation. Prior to 2022, most of the higher sulfur trains were being taken at Karn because it was easier to consume the higher sulfur coal at Karn than at Campbell Units 1 and 2 due to the challenges with removing SO2 with their DSI system utilizing hydrated lime. The planned unit outage at Campbell Unit 3 in the spring of 2023 also increased the amount of higher sulfur coal that had to be consumed by Campbell Units 1 and 2 during 2022.

Q. Please discuss the actual pebble lime expense.

A. 2023 pebble lime expense was $0.166 million lower for Karn Units 1 and 2 and $0.574 million lower for Campbell Unit 3. The lower than projected capacity factors for Karn Units 1 and 2 and Campbell 3 was the primary reason for reduced pebble lime expense during 2023. In addition to the lower than projected capacity factor at Campbell Unit 3, the unit operated almost exclusively in "Recycle Mode" vs "Lime Only Mode" during 2023, and Lime Only Mode uses significantly more pebble lime than recycle mode.

<u>Activated Carbon</u>

Q. What was Consumers Energy's estimate of activated carbon for the 2023 PSCR Plan case?

A. Consumers Energy projected the cost of activated carbon for 2023 to be $2.271 million as reflected on Exhibit A-17 (NJH-8), line 8, column (h), based on projected generation and Activated Carbon Injection operations at Karn and Campbell.

Q. What were the actual activated carbon expenses?

A. As reflected on Exhibit A-17 (NJH-8), line 8, column (i), actual activated carbon expenses for 2023 were $1.684 million, $0.587 million lower than projected.

Q. Why were activated carbon expenses lower than projected?

A. The 2023 activated carbon expense was $0.480 million lower than projected at the Campbell site due to lower-than-projected generation, the consumption of higher sulfur coal which generally contains less mercury, and better management of the operating limits for mercury.

The 2023 activated carbon expense was $0.106 million lower than projected at the Karn site due to the fact that no new deliveries of activated carbon were made to Karn in 2023. The last delivery was made in December 2022 and was sufficient for remaining plant operation in 2023.

<u>2023 Base Load Power Plant Generating Cost Efficiency</u>

Q. Why was Exhibit A-10 (NJH-7) included in this filing?

A. This information was provided in response to the MPSC's Report on Status of Power Quality in Michigan in Case No. U-15945.

<u>Wind Asset Performance Data</u>

Q. Please describe Exhibit A-18 (NJH-9).

A. Exhibit A-18 (NJH-9) presents performance details regarding the Company's owned wind assets. The Commission's September 28, 2023 Order in Case No. U-20803 required this information to be included in future PSCR reconciliation proceedings. Specifically, Exhibit A-18 (NJH-9) includes the 2023 gross actual generation, the 2023 actual and target capacity factor, the 2023 actual and target time-based availability, and the 2023 lost potential MWh due to planned maintenance, repair maintenance, and regulatory curtailment.

Q. Please describe Gross Actual Energy reflected in Exhibit A-18 (NJH-9), column (b).

A. Gross Actual Energy is the gross volume of energy produced by a wind farm during a specific period. The Gross Actual Energy does not represent any adjustment for station power (amount of energy consumed by the wind farm during operations).

Q. Please describe capacity factor reflected in Exhibit A-18 (NJH-9), column (c).

A. Capacity factor is the measure of how often a generation unit operates during a specific period of time. Capacity factor is presented as a percentage and is calculated by dividing the actual unit generation output by the maximum possible generation output. The Company's target capacity factor is presented in Exhibit A-18 (NJH-9), column (d).

Q. Please describe time-based availability reflected in Exhibit A-18 (NJH-9), column (e).

A. Time-based availability is the measure of the hours during which the turbine is available during a specific overall period of time. Time-based availability is presented as a percentage, and 97% is generally considered first quartile performance in the industry. All except one (which only narrowly missed this performance level) of the Company's parks outperformed this high standard. The Company's targeted time-based availability and actual availability is presented in Exhibit A-18 (NJH-9), column (f).

Q. Please describe potential lost energy for planned and repair maintenance reflected in Exhibit A-18 (NJH-9), columns (g) and (h).

A. The potential lost energy for planned and repair maintenance is a calculation of how much energy could have been generated during the periods in which the turbines were out of service. The energy loss is only hypothetical because the calculation assumes sufficient fuel (i.e. wind speed) would have been available for the turbines to operate during the time frame in which they were unavailable for planned and repair maintenance, which in reality would not always be true.

Q. Please describe lost energy for regulatory curtailment reflected in Exhibit A-18 (NJH-9), column (i)?

A. Curtailment reflects the adjustment of the wind turbine blade angles (i.e. parallel to the wind) to slow them down or stop them from turning (also known as "idling"). Wildlife curtailment is implemented when the risk of collision is expected to be high for bird and bat migration through the turbine sweep area, resulting in a reduction in bird and bat collision fatalities. Icing curtailment may also be implemented for local special use permit compliance reasons. The last reason for curtailment is possible implementation for energy market reasons, this typically does not affect the Consumers Energy wind fleet, due to primary dispatch as a "must run" resource.

Q. Did the Company experience any asset failures during 2023?

A. Yes. The Company experienced five pad-mounted transformer failures during 2023, four at Gratiot Farms and one at Crescent wind. Three of the failures were unexpected, one failure had high levels of gassing so the Company took it off-line as a preventative measure, and the last pad-mounted transformer experienced a bushing failure and oil was leaking. This final failure was discovered on rounds before it flashed over internally.

Q. How did the Company manage these failures to minimize lost energy?

A. In each of these cases after the failure occurred, tagging was set in place and site personnel performed an inspection. Upon inspection, the pad-mounted transformer was bypassed, and the rest of the circuit was brought back online minus one tower. Typically the balance of the circuit was returned to service in less than 12 hours except for the turbine that experienced the failure. Employing this methodology significantly reduced the amount of lost energy since it was usually a single turbine that was left out of service until the pad-mounted transformer replacement was accomplished and testing could be arranged.

Q. What other actions has the Company taken to minimize lost energy?

A. The Company established an inventory of spare pad-mounted transformers to ensure repair work could be accomplished in a more timely manner than could be achieved without the spare transformers. One of the factors that led to this decision is the fact that pad-mounted transformer delivery times have increased from 20-30 weeks to a full year.

In addition to the establishment of an inventory of spare pad-mounted transformers, the Company is performing quarterly rounds and is performing annual dissolved gas analysis testing. The Company believes that these practices allow for the early identification of a potential transformer failure and leads to more timely and less costly repairs. A summary of the 2023 failures is provided below.

Wind Asset	Pad-mounted transformer	Failiure Date	Returned to service date
Crescent Wind	#55	11/9/2023	1/26/2024
Gratiot Farms	#49	1/4/2023	1/7/2023
Gratiot Farms	#42	1/19/2023	9/13/2023
Gratiot Farms	#4	2/7/2023	6/9/2023
Gratiot Farms	#27	3/18/2023	6/9/2023

Q. What is your assessment of the performance of the Company's wind generation assets during 2023?

A. Overall, the Company's wind assets exceeded their targeted time-based availability and, as a result, generated value for customers. Although the actual capacity factors fell short of target capacity factor, the wind generation fleet's exceedance of its time-based availability reflects the fact that the Company maintained its wind generation assets in a condition which would allow for creation of customer value.

Ludington Replacement Power Costs

Q. Please discuss Exhibit A-19 (NJH-10) Revised.

A. Exhibit A-19 (NJH-10) Revised presents the 2023 Ludington outages which occurred as a result of defective work performed by TAES. The Company has removed replacement power expense associated with these outages from this reconciliation and has recorded these replacement power costs into a regulatory asset account that was established pursuant to the Commission's May 18, 2023 Order in Case No. U-21310. Specifically, this order approved the joint application of Consumers Energy and DTE Electric Company for cost deferral accounting and a regulatory asset for the costs incurred with remediating the defective work performed by TAES. In total, the Company has recorded into the regulatory asset account $927,907 of replacement power costs incurred in 2023 as a result of defective TAES work. Company witnesses Hahn, Feazel, and Raymond T. Scaife reflect the removal of these replacement power costs in their direct testimony and exhibits.

Q. How did the Company identify Ludington unit outages that occurred as a result of defective work performed by Toshiba?

A. The Company documents its unit outages on the Ludington units and reports the outage information to GADS. To identify whether the outage should be evaluated for replacement power costs, the Company reviews the cause of the outage and the work performed. If the outage was caused by or related to required inspections and/or repairs of equipment which was subject to issues with Toshiba workmanship, the outage is attributed to Toshiba. In evaluating the cause of the outage and/or the work performed, the Company also considers whether the scope of normal planned maintenance activities has increased and resulted in extending normal maintenance outages.

Conclusion

Q. Please provide a conclusion of your testimony.

A. My testimony described certain outages experienced in 2023 at the Company's fossil-fueled electric generating units and the Ludington Pumped Storage Plant, explained the expense associated with emission allowances for oxides of nitrogen and Sulfur Dioxide and explained the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon. All generator outages were performed in a reasonable and prudent manner on the part of Consumers Energy. All expenses associated with emissions allowances and consumption of urea, aqueous ammonia, lime, and activated carbon were incurred in a reasonable and prudent manner. Finally, the Company's time-based availability for its wind generation fleet exceeded its plan.

Q. Does this conclude your direct testimony?

A. Yes.

Report Period: January 2023 to December 2023

CAMPBELL 1-2 - CAMPBELL 1							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
20	MO	3/7/2023 0:01	3/17/2023 23:59	1400	Economic Reserve Shutdown. Maintenance Outage 3/7 - 3/17. 1A FDF repair	262.97	68371.34
23	ME	3/17/2023 23:59	3/21/2023 1:01	1400	Economic Reserve Shutdown. 1A FD fan repairs	73.03	18988.67
24	MO	4/26/2023 10:41	4/26/2023 11:15	4460	Turbine overspeed tests.	0.57	147.33
25	U1	4/26/2023 11:15	4/28/2023 20:52	740	1C BCWP pump replacement	57.62	14980.33
41	U1	6/6/2023 5:09	6/7/2023 1:24	9900	U1 Tripped during simulated OS test portion of valve test.	20.25	5265
49	U1	6/23/2023 22:34	6/24/2023 21:57	250	1E feeder speed sensor failure, all other feeders hogged in, trip on drum lvl.	23.38	6079.67
56	U1	7/6/2023 21:56	7/15/2023 4:31	760	1D BCWP S. discharge valve large packing leak	198.58	51631.66
65	U1	7/24/2023 13:31	7/25/2023 6:07	310	1B mill capacitor failed during PMT, all feeders tripped causing MFT.	16.6	4316
66	U1	7/25/2023 9:22	7/25/2023 14:28	9900	low drum lvl trip, high throttle pressure	5.1	1326
81	U2	8/16/2023 19:06	9/5/2023 1:51	1000	boiler tube leak(s)	462.75	120315

CAMPBELL 1-2 - CAMPBELL 2							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
3	MO	1/3/2023 0:16	1/14/2023 13:32	1000	Maintenance Outage, boiler tube leak.	277.27	98429.66
16	U1	1/14/2023 14:06	1/14/2023 21:16	1400	FD fans tripped while automating.	7.17	2544.17
17	MO	1/15/2023 2:54	1/15/2023 5:23	4460	Turbine overspeed testing.	2.48	881.58
35	MO	3/6/2023 0:01	3/11/2023 0:26	1060	Economic Reserve Shutdown. MO 3/6 - 3/10. 1x RH tube leak. Ash pit trough repair	120.42	42747.91
38	U1	3/14/2023 18:21	3/15/2023 9:35	3831	Lost aux steam/steam seals.	15.23	5407.83
73	U1	5/16/2023 18:47	6/3/2023 7:48	640	201B packing leak, worse.	421.02	149460.92
107	U1	8/4/2023 20:35	8/10/2023 11:42	4291	Circuit oil cooler leak (water into the oil)	135.12	47966.42
108	U1	8/10/2023 13:39	9/29/2023 9:30	3401	SUBFP failure.	1195.85	424526.73
109	SF	8/10/2023 11:42	8/10/2023 13:39	3401	SUBFP failure.	1.95	692.25
110	SF	9/29/2023 9:30	9/29/2023 12:50	3401	SUBFP failure.	3.33	1183.33
111	U1	9/29/2023 12:50	1/1/2024 0:00	3401	SUBFP failure.	2244.17	796679.17

CAMPBELL 3 - CAMPBELL 3							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
67	U1	3/10/2023 10:32	3/10/2023 15:40	800	Unit trip due to drum level swing. Hot restart.	5.13	4319.19
98	PO	3/31/2023 16:47	5/10/2023 8:46	1000	Planned Outage. Boiler Tube leak repair. Catalyst replacement.	951.98	800998.78
111	U1	5/14/2023 18:59	5/30/2023 8:44	1035	Boiler leak. Unit in Forced Outage.	373.75	314473.25
112	MO	5/11/2023 8:21	5/11/2023 9:09	4460	Turbine Overspeed Test.	0.8	673.12
202	MO	7/7/2023 17:03	7/25/2023 10:37	4040	#2 Turbine bearing vibration issues.	425.57	357731.34
231	U1	8/28/2023 10:24	9/4/2023 4:56	800	Drum swing after south side mills tripped due to breaker issue.	162.53	136571.67
324	U1	11/20/2023 16:15	12/12/2023 19:52	1040	Superheat tube leak. Unit offline.	531.62	448094.5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21258
Exhibit No.: A-14 (NJH-5)

Witness: NJHoffman
Date: March 2024

GENERATION PERFORMANCE STATISTICS
JANUARY 1, 2023 TO DECEMBER 31, 2023

Line No.	(a)	(b)	(c)	(d)	(e)
	Unit	Unit Availability	MWh Availability	Periodic Factor	Random Outage Rate
1	Campbell 1	87.20%	81.34%	0.00%	18.66%
2	Campbell 2	49.50%	38.70%	9.33%	57.32%
3	Campbell 3 (CE)	72.02%	69.16%	10.87%	22.41%
4	Karn 1	72.07%	65.59%	3.77%	31.84%
5	Karn 2	74.66%	69.09%	5.33%	27.02%
6	Karn 3	52.02%	46.19%	11.46%	47.83%
7	Karn 4	80.70%	77.86%	4.07%	18.84%
8	Zeeland Simple Cycle	83.84%	77.97%	14.73%	8.56%
9	Zeeland Combined Cycle	78.09%	73.41%	11.86%	16.71%
10	Jackson CC	93.62%	85.75%	7.37%	7.43%
11	Covert CC	89.21%	83.30%	8.18%	9.28%
12	Total Fossil CE[1]	80.50%	74.58%	9.43%	17.65%
13	Base Load Fossil CE	70.39%	63.99%	6.26%	31.74%
14	Ludington 1-6	82.64%	80.58%	9.58%	10.88%
15	Total Hydro	78.60%	69.68%	15.48%	17.56%

[1] Does not include Karn 3 and Karn 4.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-7
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 15

Hoffman 2025 Direct Testimony

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for reconciliation of its power supply cost	)	Case No. U-21424
recovery plan (Case No. U-21423) for the	)	
12 months ended December 31, 2024.	)	
______________________________________	)	

DIRECT TESTIMONY

OF

NATHAN J. HOFFMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

March 2025

Q. Please state your name and business address.

A. My name is Nathan J. Hoffman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director – Fossil Generation.

Q. Please describe your educational background.

A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from Ferris State University. In 2017, I received a Master of Business Administration with a concentration in Advanced Management Tools and Concepts from Ferris State University.

Q. Please describe your business experience.

A. In 2005, I joined Consumers Energy at the J.H. Campbell ("Campbell") Generating Complex and progressed through positions from Engineering Technical Analyst to the Executive Director – Fossil Generation. In my various roles at Consumers Energy, I served as a subject matter expert for boiler and piping systems and was an embedded engineering resource in the Operations Department responsible for monitoring plant performance and troubleshooting. I also planned and executed outages to ensure that they were performed in a prudent and expeditious manner, as well as managed the site maintenance organization tasked with maintaining the plant systems and equipment. As the Executive Director – Fossil Generation, I have overall responsibility for the safe and excellent operations of the Fossil Generation Fleet. In this role, I also manage the overall Operating and Maintenance and Capital budgets, develop site specific staffing plans, develop strategies to meet Company objectives, and instill a culture of continuous improvement. I further oversee the performance of the Site's Operations, Maintenance, Fuel Handling, and Environmental and Technical Services departments.

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

A. Yes, I provided testimony in the following MPSC Cases:

- Case No. U-21049: the Company's 2022 Power Supply Cost Recovery ("PSCR") Reconciliation Case;
- Case No. U-21257: the Company's 2023 PSCR Plan Case;
- Case No. U-21423: the Company's 2024 PSCR Plan Case;
- Case No. U-21258: the Company's 2023 PSCR Reconciliation Case; and
- Case No. U-21592: the Company's 2025 PSCR Plan Case.

<u>Purpose of Direct Testimony</u>

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

A. The purpose of my direct testimony is to:

- Describe the reasonableness and prudence of certain outages experienced in 2024 at the Company's fossil-fueled electric generating units and the River Hydroelectric generating units ("River Hydros");
- Describe the outages experienced in 2024 at the Company's Ludington Pumped Storage Plant ("Ludington"), including the outages at Ludington resulting from defective, non-conforming, and incomplete work performed by Toshiba America Energy Systems Corporation ("TAES"), and the associated replacement power costs, which the Company has recorded to the regulatory asset approved by the Commission in Case No. U-21310;
- Explain the expense associated with emission allowances for oxides of nitrogen ("NO_x") and Sulfur Dioxide ("SO_2");
- Explain the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon; and
- Explain the 2024 performance of the Company's owned wind assets.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-11 (NJH-1)	Event Summary Report, January 2024 to December 2024;
Exhibit A-12 (NJH-2)	Event Identification – Outages;
Exhibit A-13 (NJH-3)	Periodic Outage Reports;
Exhibit A-14 (NJH-4)	2024 Fossil and Pumped Storage Outages Occurring for Twenty-Eight Days or More;
Exhibit A-15 (NJH-5)	Generation Performance Statistics (January 1, 2024 to December 31, 2024);
Exhibit A-16 (NJH-6)	Comparison of Consumers Energy and Generating Availability Data System ("GADS") Averages for Similar Units Equivalent Availability;
Exhibit A-17 (NJH-7)	2024 Base Load Generation Power Plant Cost Efficiency;
Exhibit A-18 (NJH-8)	Chemical Reagent Expense (January 1, 2024 to December 31, 2024);
Exhibit A-19 (NJH-9)	2024 Wind Asset Performance Data;
Exhibit A-20 (NJH-10)	2024 Ludington Outages; and
Exhibit A-21 (NJH-11)	Campbell Unit 2 Outage Pre-Start Check Sheet.

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

A. Yes.

<u>2024 Outages</u>

Q. Have you provided a listing of all 2024 outages?

A. Yes. The Event Summary Report, Exhibit A-11 (NJH-1), lists all unit outages and trips. The report shows 17 events on the coal units; 98 on the Ludington Units; 71 collectively on the Zeeland Combined Cycle Plant ("Zeeland CC") (Units 3, 4, and 5), Covert Gas Plant ("Covert"), and Jackson Gas Plant ("Jackson"); 22 on D.E. Karn ("Karn") Units 3 and 4;

17 on the Zeeland Simple Cycle ("Zeeland SC") (Units 1 and 2); and 640 on the River Hydro units. The total number of outage events for the fleet was 865,441 more than in 2023, and 342 more than in 2022. This increase in outages events was due to the increase in River Hydro events, discussed later in this testimony. Excluding the River Hydro events, the outage events total would in fact be lower than both 2023 and 2022, at just 225 outages.

Exhibit A-11 (NJH-1) provides a description of each event, including the event start time, event end time, cause code,[1] duration in equivalent hours, and equivalent MWh. The equivalent MWh calculation assumes that the units would have operated at 100% capacity factor.

Q. Has the Company also calculated the lost generation for the Ludington Units in accordance with the Settlement Agreement approved in the Commission's June 28, 2018 Order in Case No. U-17918-R?

A. Yes. Company witness Sarah K. Seng provides the economic MWh loss calculations for the Ludington Units assuming they were operating and dispatchable. These calculations are presented in Exhibit A-27 (SKS-3).

Q. Would you please define the words "outage," "trip," and "event"?

A. A unit "outage" on a base-load unit is defined as the period from when the circuit breaker opens, separating the unit from the electric system, to when it closes, tying the unit to the electric system and making it available for dispatch, and the unit is not in economic reserve status. A unit "outage" on a cycling or peaking unit is defined as the period from when the Company's Electric Supply Operations Department releases a unit, making it unavailable,

[1] Cause codes used are taken from the Data Reporting Instructions of the North American Electric Reliability Corporation ("NERC") Generating Availability Data System. Explanations for the cause codes can be found at: Data Reporting Instructions (nerc.com)

to when the plant reports to Electric Supply Operations that the unit is available for service. For the purposes of these definitions, the coal and river hydro units are considered base-load units, and the Zeeland, Jackson, Covert, and Karn Units 3 and 4 are all considered cycling units. Zeeland Units 1 and 2 are considered peakers. Base load generation refers to the minimum amount of electric power required to be delivered to customers over a given period of time at a steady rate. Base load generating units are units which are typically operated to serve customer loads on an around-the-clock basis.

A "trip" is a unit outage that begins when protective devices automatically separate a unit from the electric system, or the operator initiates a manual and immediate separation. This is in contrast to the normal controlled shutdown process where operators may spend several hours slowly reducing pressure and load before separating the unit from the system.

An "event" is a one-line entry on the Event Summary Report. Each line on the Report contains an outage "event." The outage event classification is divided into eight distinct event types: (i) Planned Outage; (ii) Maintenance Outage; (iii) Planned Outage Extension; (iv) Maintenance Outage Extension; (v) Startup Failure; (vi) Unplanned (Forced) Outage-Immediate; (vii) Unplanned (Forced) Outage–Delayed; and (viii) Unplanned (Forced) Outage-Postponed. Exhibit A-12 (NJH-2) explains the different types of outages shown on Exhibit A-11 (NJH-1).

Q. Have you documented outage occurrences in more detail?

A. Yes. In addition to documenting all of the 2024 outages reported on page 3 of this testimony and reflected in Exhibit A-11 (NJH-1), outage information sheets were also prepared for generating units that had lower availability averages than those shown in GADS data discussed later in my direct testimony. The information sheets are provided as

Exhibit A-13 (NJH-3). Each sheet contains the same statistical data found on Exhibit A-11 (NJH-1), as well as: (i) an expanded description of the event; (ii) a cause of the event; (iii) the work that was done to correct the root cause for forced outages or the work that was performed during maintenance and periodic outages; (iv) other work, if any, that was performed; (v) a description of work that extended the outage, if any extension occurred; and (vi) why that work was performed.

Additionally, the Company prepared a Periodic Outage, Maintenance Outage, or Forced Outage Information sheet for each of the events lasting 28 days or more on the fossil, pumped storage, peaking, and River Hydro units shown on Exhibit A-11 (NJH-1).

Q. Before discussing specific outages, do you have any general comments about outages in the Company's generation fleet?

A. Yes, particularly concerning the Company's older units. Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist.

<u>**Fossil, Cycling, and Pumped Storage Outages Planned for 28 Days or More**</u>

Q. In Case No. U-21423, how many outages were planned for 28 days or more?

A. My direct testimony and Exhibit A-10 (NJH-1) in that case identified nine such outages.

Q. Were all nine outages completed during the plan year?

A. Yes, however, only eight of the planned outages lasted 28 days or more.

Q. Which outage had a shorter outage duration and why?

A. The Ludington Unit 3 outage was originally scheduled for a 47-day duration; however, the outage was able to be reduced to 27 days, starting on October 30, 2024 and concluding

November 26, 2024. A portion of this outage was associated solely with defective, non-conforming, and incomplete work by TAES. The portion of the replacement power costs related to this work was removed to the regulatory asset approved by the Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related outages are discussed later in my testimony.

Q. Did the Company conduct additional outages of 28 days or more in 2024?

A. Yes. In addition to the eight planned outages which lasted longer than 28 days, the Company conducted seven additional outages for a total of fifteen outages that lasted 28 days or more. The additional outages included Ludington Unit 4, Ludington Unit 5, Ludington Unit 6, Covert Unit 2, Karn Unit 3, and two outages at Karn Unit 4. All fifteen outages are identified in Exhibit A-14 (NJH-4).

Q. Has your review of the outages listed in Exhibit A-14 (NJH-4) led you to a conclusion concerning these outages?

A. Yes. I have concluded that all of the outages listed in Exhibit A-14 (NJH-4) were carefully planned, prudently managed, and free of negligence on the part of Consumers Energy as to either causation or extension of outage time. Below is a brief summary of each of the outages listed in Exhibit A-14 (NJH-4).

<u>Campbell Unit 1</u>

The Campbell Unit 1 outage began on March 1, 2024, and lasted 30 days, concluding March 31, 2024. This planned outage was for routine valve maintenance and to address governor valve instability at lower loads. Additional maintenance tasks included explosive backpass cleaning and the installation of a 1D boiler circulating water pump. All of which was necessary to maintain unit reliability.

Campbell Unit 2

The Campbell Unit 2 outage began on August 4, 2023 due to a tube leak in the hydraulic coupling circuit oil cooler. The tube leak resulted in water intrusion into the oil system, thereby forcing the unit to be removed from service. Subsequently, on August 10, 2023, the SUBFP experienced a thrust event causing damage to the internal flow element, thrust bearing, and drive coupling. The unit was out of service for the remainder of 2023 and the first 101 days of 2024, concluding on April 10, 2024. A detailed discussion of the extended outage is provided later in this direct testimony.

Campbell Unit 3

The outage at Campbell Unit 3 was scheduled to begin April 1, 2024 and was projected to last for 30 days – concluding May 1, 2024. The outage began on April 12, 2024 and lasted 61 days, instead of the planned 30 days, and concluded on June 12, 2024. The outage began as a maintenance outage to repair tube leaks. The outage was extended due to a failed turbine turning gear upon startup. During the outage, it was found that the teeth in the planetary gear assembly had been sheared off, due to assumed cyclic fatigue. The turning gear assembly was last inspected in 2016, with no findings. Planetary gears and drive shaft replacement was performed to allow the unit to resume operation until the planned retirement in May of 2025.

Karn Unit 3

The outage at Karn Unit 3 began on May 3, 2024 and lasted 29 days, concluding May 31, 2024. This outage was a spring outage to repair a known boiler water wall leak, sectionalized replacement of sections BB and BC of combustion air heater, inspection of the deaerator heater and storage tank, and inspection and certification of boiler code safety relief valves.

Karn Unit 4

The first outage at Karn Unit 4 began on April 20, 2024 and lasted 31 days, concluding May 20, 2024. This outage was a periodic outage to perform six-year safety inspections of the Deaerator and Deaerator Heater and Storage Tank ("DAST"). During the inspection, it was found necessary to replace the obsolete deaerator heater's five safety relief valves due to parts being unavailable. Associated balance of plant repairs were also completed.

The second outage at Karn Unit 4 began on October 28, 2024 and lasted 31 days, concluding on November 27, 2024. This outage was for High Voltage Distribution ("HVD") lines and Sync Wire replacement. Due to expanded requirements for the Ash Field caps beyond the original design, there was interference caused between the ground elevation and the wire placement, requiring the transmission lines to be raised. During this outage, additional work was performed including a boiler water wall tube leak repair, balance of plant work, and Karn Unit 4 steam strainer seal replacement.

Ludington Unit 1

The outage at Ludington Unit 1 began on February 12, 2024 and lasted 40 days, concluding March 22, 2024. This outage was scheduled for three-year maintenance activities. The Company also took the opportunity afforded by the outage to facilitate litigation-related inspections demanded by TAES and its parent company, Toshiba Corporation, pertaining to Consumers Energy's and DTE Electric Company's ("DTE") ongoing lawsuit against those parties. The litigation-related inspections did ***not*** require an extension to the outage. Maintenance work performed during the outage included repair on cavitation damage on wicket gates, which was found during inspections, along with lower end seal replacements of five of the wicket gates. Because the outage would have been the same length regardless of TAES-related defects, the replacement power costs associated with the outage were not removed to the regulatory asset approved by the Commission in Case No. U-21310. Additional discussion on TAES-related outages can be found later in my testimony.

Ludington Unit 2

The outage at Ludington Unit 2 was scheduled to begin, February 12, 2024, and last for 40 days. Instead, the outage began on February 1, 2024, but still lasted 40 days, concluding on March 15, 2024. This outage was scheduled for three-year maintenance activities. The Company also took the opportunity afforded by the outage to facilitate litigation-related inspections demanded by TAES and its parent company, Toshiba Corporation, pertaining to Consumers Energy's and DTE's ongoing lawsuit against those parties. The litigation-related inspections did ***not*** require an extension to the outage. Work performed during the outage included certain typical nine-year outage activities, inspections on the generator and transformer, and cleaning of the generator air coolers. Because the outage would have been the same length regardless of TAES-related defects, the replacement power costs associated with the outage were not removed to the regulatory asset approved by the Commission in Case No. U-21310. Additional discussion on TAES-related outages can be found later in my testimony.

Ludington Unit 4

The outage at Ludington Unit 4 began on October 23, 2024 and lasted 29 days, concluding November 20, 2024. This was an annual periodic outage to perform Main Transformer Bank ("MTB") #2 Electrical inspections, Turbine Lube Oil Cooler maintenance, and Wicket Gate Thrust Collar inspections. During this outage, additional work was completed including Turbine Runner Cavitation and Wicket Gate Cavitation repairs, 416 pumping pole replacement, and MTB Isophase Bus Inspections. A portion of this outage was associated solely with defective, non-conforming, and incomplete work by TAES. The portion of the replacement power costs related to this work was removed to the regulatory asset approved by the Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related outages are discussed later in my testimony.

Ludington Unit 5

The outage at Ludington Unit 5 began January 29, 2024 and lasted 74 days, concluding April 11, 2024. This outage was required to facilitate litigation-related inspections demanded by TAES and its parent company, Toshiba Corporation, pertaining to Consumers Energy's and DTE's ongoing lawsuit against those parties. While the unit was down as a result of the litigation demand, additional work was performed, including inspections of the spiral case, turbine runner, MTB #3 oil addition and inspections. During the inspection of turbine runner blade, a crack was identified at the attachment weld between the turbine runner band and a turbine blade. The recommendation was to repair prior to returning to operation to avoid the risk catastrophic damage, which led to the extension of this outage. The damaged weld interface and subsequent base metal was cut out and then rebuilt with weld repair. The cause of this crack was found to be due to high stress intensification at the interface between the turbine runner band casting and a turbine blade due to internal weld defects and excessive weld root porosity during original manufacturing. Because the outage was scheduled to address Toshiba-related defective work, and then extended due to the need to repair Toshiba defects, the replacement power costs were removed to the regulatory asset approved by the Commission in Case No. U-21310, as shown in Exhibit A-20 (NJH-10). Additional discussion on TAES-related outages can be found later in my testimony.

Ludington Unit 6

The outage at Ludington Unit 6 began September 30, 2024 and lasted 30 days, concluding October 29, 2024. This was a schedule periodic outage for the purpose of MTB #3 Electrical inspections, turbine lube oil cooler maintenance, and Wicket Gate Thrust Collar inspections. During this outage, additional work was completed including Turbine Runner Cavitation and Wicket Gate Cavitation repairs, Pony Motor #2 inspections, and South Trash Rack repairs. A portion of this outage was associated solely with defective, non-conforming, and incomplete work by TAES. The portion of the replacement power costs related to this work was removed to the regulatory asset approved by the Commission in Case No. U-21310 and included in Exhibit A-20 (NJH-10). TAES-related outages are discussed later in my testimony.

Covert Unit 2

The outage at Covert Unit 2 began on May 6, 2024 and lasted 40 days, concluding June 14, 2024. It was a periodic outage for routine borescope inspections and repairs for continued reliable operation. This work included performing Selective Catalytic Reduction ("SCR") catalyst inspection and cleaning, annual calibration of the unit's fuel gas valves, inspection of the Heat Recovery Steam Generator ("HRSG") flue gas pass, replacement of the bearing and seals on the 2B ammonia injection fan, Gas Turbine borescope inspection, Gas Turbine overspeed testing, and balance of plant inspections and repairs. Additionally, during the outage, field balancing was attempted to reduce unacceptable levels of vibration in the pump during operation, caused by an unbalanced impeller. The bearings, sleeve, and impeller rings were also replaced. Exiting the outage, the pump experienced a step change increase in vibrations requiring the pump to be pulled and sent for an overhaul, before being restored to operation.

Zeeland Units 3, 4, and 5

The outages at Zeeland Units 3, 4, and 5 were all scheduled to begin on May 19, 2024 and last 28 days, concluding June 16, 2024. The outages on all three units began September 20, 2024 and lasted 40 days, concluding October 30, 2024. These outages were necessary for the installation of the overhauled Unit 5 transformer and removal of the rental transformer. While the units were down, additional work was performed including replacement of main stream non-return valves and replacement of HRSG ductwork panels, due to thinning. Upon initial energization, excessive internal gassing[2] was observed, causing a preemptive shut down to all three units. Additional operation has shown that dissolved gas production has subsided, and both Company and external experts, recommend continuing to operate the transformer and closely monitoring for any change in dissolved gas levels. If after six months there is no change in the dissolved gas levels,

[2] Internal gassing can be explained as the breakdown of transformer oil due to the presence of high level of heat within the transformer. This 'gassing' is the residual product of this oil breakdown and is routinely monitored to determine transformer health and to prevent the excessive accumulation of combustible gasses within the transformer that could pose a threat to its integrity and long-term life.

the main transformer oil will be changed, and the transformer will be considered in a satisfactory state.

Q. Did the Company conduct any outages that exceeded 90 days in duration?

A. Yes. The Company had one outage during 2024 that exceeded 90 days in duration, which was the Campbell Unit 2 outage which lasted for 101 days during 2024.

Q. Why did the Campbell Unit 2 outage exceed 90 days?

A. As previously discussed in this direct testimony, as well as both the direct testimony and rebuttal testimony in Case No. U-21258, the Campbell Unit 2 outage began on August 4, 2023, because of a tube leak in the hydraulic coupling circuit oil cooler which resulted in water intrusion into the oil system, thereby forcing the unit to be removed from service. After the tube leak repair, during post-maintenance testing on August 10, 2023, the SUBFP experienced a thrust event, which resulted in damage to the SUBFP internal flow element, thrust bearing, and drive coupling.

Q. What was the root cause of the thrusting event?

A. The Company conducted thorough evaluations of the thrusting event and narrowed the root cause to two possibilities. The two potential root causes that could have led to the event were (1) seal water injection that was not sufficiently getting through the pump seals and (2) the SUBFP having non-compressible gasses (an air bubble) trapped in the pump. While the Company's thorough evaluation of each of these potential causes of the thrusting event did consider operator error, it did not identify any errors performed by the Company which may have led to the outage.

Q. Has the Company experienced additional instances of inadequate lubrication of the seals with the seal water?

A. Yes. During the period from August 2023 through March 2024, the Company made multiple observations of erratic seal water pressure. The pressure control valve, pressure control valve controls, associated piping, and seal water filters were all inspected to determine a cause of the erratic pressure control with no causes identified.

Q. What measures does the Company have in place to ensure the system is purged of any potential trapped gases?

A. Purging of potential trapped gases is performed on a routine basis by well-trained operators and is basic operator knowledge. In this instance, as is customary before purging, a pre-job brief was held during which the activities to be performed were discussed. Upon completion of the purging activity, the operator confirmed completion of this activity on the prestart check-sheet, as shown on step 10 in Exhibit A-21 (NJH-11), which includes instructions to "[h]ave the SUBFP vented."

Q. In your opinion, did the actions of anyone at the Company cause this outage?

A. No. If anything, the actions of the operators at Company prevented a catastrophic failure of the unit. Following the reassembly of the pump in 2024, multiple attempts to operate the pump and commence startup were made. As stated in my earlier testimony, observations were made that indicated there was an issue with injection seal water pressure which was resolved through increasing the injection seal water pressure. Along with the resolution of the injection seal water pressure, the pump continued to operate with elevated vibration levels which was ultimately determined to be excited by the spare "Kopflex" coupling that was used as part of the rebuild from the August 2024 thrust event. At the time of rebuild, the only coupling available for use was a spare “Kopflex” coupling that was kept in stock. The original coupling, a Goodrich brand coupling made from titanium, was damaged as a result of the thrust event. The spare Kopflex coupling represents approximately a 67.5-pound increase in weight over the original Goodrich titanium coupling. Vibration velocity levels observed at the initial startup following the rebuild were as high as 1.0 inch per second on the outboard end of the pump and 0.8 inches per second on the inboard end of the pump, which were deemed unsafe to operate. Based on these observations, the Company worked diligently with vendors to study the vibration of the pump and design and install dynamic vibration absorbers to counteract the effect of the increase in mass of the Kopflex coupling. In parallel, efforts were made to procure a new Goodrich titanium coupling as well as engineering coupling hubs made of titanium to reduce the overall mass of the coupling assembly. In addition, the Company worked with coupling manufacturers to design and manufacture a new lighter coupling. Ultimately, the re-engineering of the coupling hubs utilizing titanium was enough to reduce the vibration within acceptable levels – 0.5 inches per second or below.

Q. Have you reviewed the peaker and hydro unit outages?

A. Yes. I reviewed the events for each peaker and hydro unit shown on the Event Summary Report, Exhibit A-11 (NJH-1). There were no peaker outages that lasted longer than 28 days in 2024.

River hydro outages greater than 28 days are summarized in the table below, including events in which there was a lack of sufficient water to run the unit. The Company’s hydro units that are considered run of river plants, do not store water, but rely on the natural flow of the river to operate. Effective 2024, the North American Electric

Reliability Corporation ("NERC") updated its Special Hydro Reporting Guidance with new reporting procedures. One such change is the classification of an outage due to lack of river flow. Per NERC guidelines,[3] "When a unit must be shut down because there is insufficient water to run all the units and there is no reservoir that would allow the units to run if called upon," these are to be categorized as U3 - Forced outage due to insufficient river flows, with a cause code of 9135 - Lack of Water. Due to these updated reporting requirements, the Company saw a significant increase in outage events.

[3] Guideline definition taken from the Hydro Assets Special Hydro Reporting Guidance presentation from of the North American Electric Reliability Corporation ("NERC") GADS Data Reporting Training Workshop.

Hydro Unit	Actual Days in 2024	Event Number(s)
Alcona 1	100	3&4
Alcona 2	65	2
Alcona 2	35	11
Allegan 1	32	4
Allegan 1	212	5
Allegan 2	60	1 & 9
Cooke 1	52	8 & 27
Cooke 2	45	7 & 15
Cooke 3	63	33
Croton 1	31	1
Croton 1	50	2 & 5
Croton 2	31	1 & 6
Croton 2	46	8 & 9
Croton 3	128	2 & 3
Croton 3	36	12 & 14
Croton 4	108	2
Five Channels 1	29	5
Five Channels 1	64	18
Foote 1	49	3 & 7
Foote 1	36	5
Foote 1	35	17 & 18
Foote 2	58	11
Hardy 1	38	1, 11, 12
Hodenpyl 1	338	1 & 2
Loud 1	34	29
Loud 2	36	12
Loud 2	42	23
Mio 1	37	1 & 6
Mio 1	69	17
Mio 1	42	18, 19, 20
Mio 2	37	11
Rogers 1	233	3
Rogers 2	233	3 & 1
Rogers 3	124	1 & 5
Rogers 3	114	4
Rogers 4	128	1
Rogers 4	114	6
Tippy 1	366	1
Tippy 3	41	17
Tippy 3	50	20
Webber 1	70	5
Webber 2	51	1
Webber 2	38	9 & 2

My review of these events and the additional information provided on Exhibit A-13 (NJH-3) leads me to conclude that those outages were conducted in a prudent manner.

Outages with a Duration of Fewer Than 28 Days

Q. How many periodic outages less than 28 days but greater than one day in length occurred on the fossil and Ludington Units in 2024?

A. As shown on Exhibit A-11 (NJH-1), 30 short periodic (planned) outages occurred on the fossil and Ludington Units in 2024.

Q. What was the purpose of these periodic outages?

A. In general, the purpose of these outages was to perform preventative maintenance activities on equipment that has been assessed as being non-functional or having gone more than one to two years without preventative or corrective maintenance.

Availability

Q. Please discuss the Company's 2024 generation unit availability.

A. The Company's 2024 generation unit availability data is shown on Exhibit A-15 (NJH-5). The Company's Total Fossil MWh availability slightly increased from 74.58% in 2023 (see Case No. U-21258, Exhibit A-14 (NJH-5), line 12, column (c)) to 78.99% in 2024 (see Exhibit A-15 (NJH-5), line 10, column (c)) due to increases in MWh availability at Campbell Units 2 and 3, Karn Unit 3, Jackson Gas Plant, and the Zeeland combined cycle units. Despite the slight decrease in MWh availability at the Campbell Unit 1, Karn Unit 4, and Covert generating units, the Company provided customer benefit in 2024. The Company quantifies this customer benefit through Net Energy Value ("NEV"). At a high level, the NEV of a generating unit is the difference between the market value of the energy produced and the cost of producing and supplying that energy. The Company's estimated 2024 NEV was $312.7 million[4] as compared to the 2023 amount of $225.7 million,

[4] The NEV calculation is based upon data pulled from PCI P&L actuals on February 5, 2025.

including the Company's owned wind assets, an amount which is directly attributable to MWh availability.

The Company's 2024 base load fossil MWh availability increased from 63.99% in 2023 (see MPSC Case No. U-21258, Exhibit A-14 (NJH-5), line 13, column (c)) to 73.18% in 2024 (see Exhibit A-15 (NJH-5), line 11, column (c)) due to increases in MWh availability at Campbell Units 2 and 3, and Karn Unit 3, Jackson Gas Plant, and Zeeland Units.

Q. Did the Covert Units experience issues that affected their availability?

A. Yes. The Covert units experienced issues with circulating water pumps on each of the three units that resulted in failures of pumps or resonant frequency vibration issues. Each Covert unit has two circulating water pumps that circulate water from the condenser to the cooling towers. Depending on ambient conditions, a unit may experience a derate when one of the circulating water pumps is out of service. The Company has been working with the pump's original equipment manufacturer as well as other pump maintenance vendors to identify the potential causes of the pump failures and excessive vibration. In working with our vendors, the Company has identified modifications that have been made to a pump that will be installed during the Covert Unit 2 Spring 2025 outage. The performance of the modified pump will be studied to determine if the same modification should be made on the other pumps. Additionally, any time a pump fails and must be pulled from its pit, a unit outage is required.

The Covert Generating site also experienced impacts to availability due to stack particulate matter ("PM") testing results as part of the five-year renewable operating permit testing requirements. Gas generation sites utilize EPA Method 5/202 for identifying the quality of condensable PM emitted from a stack. While EPA Method 5/202 is an approved test method, this method is not well suited for testing very low PM concentrations due to inherent limits of the method that can lead to high bias and uncertainty. When coupled with very low permit limits, this testing can yield high biased results that lead to a permit exceedance even though no apparent source of particulates in the operating unit can be identified. In the case of Covert Units 1 and 3, PM testing results indicated an exceedance of the unit's air permit limits. As a result, units were removed from service out of an abundance of caution until the test data could be validated. The Company worked to identify the maximum amount of heat input at which the units could be operated while not violating permit requirements to return to service until additional testing plans could be developed. Through extensive causal analysis, it was determined that there were no operational abnormalities contributing to the excessive PM test results; rather, inconsistencies and bias with the testing method led to the erroneous concentration results.

Lastly, Covert Unit 3 was removed from service due to quench cracking located in one of the circumferential welds in the reheat cross over pipe. The root cause of quench cracking was due to failure of the reheat attemperator spray nozzle. Failure of the spray nozzle allowed for the creation of a flow path for attemperator water to leak behind the attemperator liner and cause the quench cracking of the circumferential weld. During the outage, the section of reheat cross over piping and attemperator assembly was replaced.

<u>Comparison to GADS Data</u>

Q. What is GADS?

A. GADS is the Generator Availability Data System. NERC's GADS maintains operating histories for more than 5,000 generating units in North America. GADS is recognized as a valuable source of reliability information for total unit and major equipment groups. GADS contains information about the performance of electric generating equipment and provides assistance to those researching information on power plant outages and supports equipment availability analyses. GADS is a mandatory industry program for conventional generating units 20 MW and larger.

Q. Did you compare the availability of the Company's base load fossil units to GADS data?

A. Yes. I compared the availability of the Company's base load fossil units to both the 2023 and 2019 through 2023 GADS data for comparable sized and fueled units. The results are shown on my Exhibit A-16 (NJH-6). The availability of Campbell Units 1 and 3 was higher than the one-year GADs data. The availability of Campbell Unit 2 was below both the one-year and five-year comparisons. The availability of Campbell Units 1, 2, and 3 were all below the five-year comparisons.

Q. Please explain the outages that contributed to lower-than-average availability on a MWh basis.

A. Campbell Unit 1 experienced a total of four outages during 2024, one of which lasted 38 days and is discussed in greater detail earlier in my direct testimony. Additional outages included turbine overspeed testing, 1C coal pulverizer feed issue that resulted in 20 MW load swings causing the unit to trip, and a super heat tube leak.

Campbell Unit 2 experienced a total of seven outages during 2024, one being the SUBFP outage discussed in detail earlier in this direct testimony, and six other unplanned outages, including circuit oil cooler leaks, a turbine valve issue when it closed unexpectedly causing boiler overpressure and the unit tripped, a leak on thrust oil protective trip device, a forced outage due to a broken pin rack on the 2B secondary air heater and left, turbine throttle valve steam leak, and another forced outage to address 201A and 210 valves.

Campbell Unit 3 experienced a total of two outages during 2024: one planned maintenance outage to repair a tube leak and one unplanned due to a turbine turning gear failure.

Q. Did you review all of the outages shown on Exhibit A-11 (NJH-1)?

A. Yes. I reviewed all the base load fossil and pumped storage outages that lasted longer than 24 hours.

Q. In your opinion, did Consumers Energy act in a reasonable and prudent manner in connection with the outages you reviewed on Exhibit A-11 (NJH-1)?

A. Yes.

NO_x Allowance Expenses

Q. Did Consumers Energy forecast NO_x expenses in the 2024 PSCR Plan case?

A. No. Consumers Energy did not forecast NO_x expenses in the 2024 PSCR Plan case because SCRs were installed and have significantly reduced NO_x emissions and offset the need to purchase allowances. The SCRs were installed to comply with the Clean Air Interstate Rule ("CAIR"), which was replaced by the Cross-State Air Pollution Rule ("CSAPR"). CSAPR is a cap and trade rule much like CAIR. CSAPR governs the emission of SO_2 and NO_x from fossil-fueled electric generating units through the use of an allowance based "cap and trade" program. Under CSAPR, NO_x is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or seasonal) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. SO_2 is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR took effect on January 1, 2015 and Phase II became effective on January 1, 2017. In 2024, no allowance purchases were required for either the annual or seasonal requirements, and there were no expenses associated with the allowances allocated by the Michigan Department of Environment, Great Lakes, and Energy.

Q. Did Consumers Energy receive revenue credits in 2024 related to the sale of NO_x allowances?

A. No. The Company did not sell NOx emission allowances in 2024. As such, Company witness Leanna E. Feazel's Exhibit A-6 (LEF-1) does not reflect any expense or revenue credits for NOx emission allowances.

SO_2 Allowance Expenses

Q. Did Consumers Energy incur expenses or receive revenue credits in 2024 related to the SO_2 Allowance Program?

A. Yes. Although the Company did not sell SO_2 emission allowances out of its inventory in 2024, it did receive revenue for a portion ($54) of the Company-allocated SO_2 emission allowances during the annual US Environmental Protection Agency auction.

Q. Are the actual expenses and credits for SO_2 contained in Consumers Energy's 2024 Reconciliation?

A. Yes. Company witness Feazel includes the actual SO_2 expenses and credits in Exhibit A-6 (LEF-1), line 20.

Urea Expenses

Q. What was Consumers Energy's estimate of urea expenses for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of urea for 2024 to be $3.7 million as reflected on Exhibit A-18 (NJH-8), line 8, column (b), based on projected generation and SCR operations at the Campbell Complex for Campbell Units 2 and 3.

Q. What were the actual urea expenses?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (c), actual urea expense for 2024 was $2.03 million, $1.67 million lower than projected.

Q. Why were actual urea expenses lower than projected?

A. Urea expenses were lower than forecast due to less consumption and prices being approximately 30% lower than projected. The forecasted value was set conservatively high, based on recent high prices and volatility. The forecasted urea price was $761/ton, whereas the actual urea cost came in at only $528/ton.

Aqueous Ammonia

Q. What was Consumers Energy's estimate of aqueous ammonia for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of aqueous ammonia for 2024 to be $2.04 million as reflected on Exhibit A-18 (NJH-8), line 8, column (d), based on projected generation and SCR operations at the Covert plant and Zeeland Combined Cycle.

Q. What was the actual aqueous ammonia expense?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (e), actual aqueous ammonia expense for 2024 was $1.67 million, $0.378 million lower than projected.

Q. Why were actual aqueous ammonia expenses lower than projected?

A. The aqueous ammonia expense for Zeeland was lower than projected due to the actual unit cost landing 35% below the projected unit cost, which was forecasted conservatively high, due to recent price and volatility.

The aqueous ammonia expense for Covert was approximately 15% lower than projected because less was required than forecasted. Although Covert's actual quantity was less than forecasted, it aligns with site dispatch/heat rate.

<u>Lime</u>

Q. What was Consumers Energy's estimate of lime expense in the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of lime for 2024 to be $8.4 million as reflected on Exhibit A-18 (NJH-8), line 8, column (f), based on projected generation and Spray Dry Absorber ("SDA") and Dry Sorbent Injection ("DSI") operations at the Karn and Campbell plants.

Q. What were the total actual lime expenses?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (g), the actual lime expense for 2024 was $10.22 million, $1.81 million higher than projected. The Company consumes hydrated lime at Campbell Units 1 and 2 and consumes pebble lime at Campbell Unit 3. The hydrated lime expense at Campbell Units 1 and 2 was 22%, or $2.56 million, above forecast.

Q. Why were the actual hydrated lime expenses higher than projected?

A. 2024 hydrated lime expenses were higher than projected for Campbell Units 1 and 2 primarily due to the quality of the coal delivered and consumed at Campbell Units 1 and 2. As the units continued to consume the coal that the Company had available, there were periods in which the coal was western bituminous, which has significantly higher sulfur content than typical powder river basin, which is what the forecast model is based on.

Q. Please discuss the actual pebble lime expense.

A. 2024 pebble lime expense was 5% or $0.750 million lower for Campbell Unit 3. In 2024, Campbell Unit 3 operated almost exclusively in "Recycle Mode" vs "Lime Only Mode," and Lime Only Mode uses significantly more pebble lime than recycle mode.

Activated Carbon

Q. What was Consumers Energy's estimate of activated carbon for the 2024 PSCR Plan case?

A. Consumers Energy projected the cost of activated carbon for 2024 to be $2.2 million as reflected on Exhibit A-18 (NJH-8), line 8, column (h), based on projected generation and Activated Carbon Injection operations at Campbell.

Q. What were the actual activated carbon expenses?

A. As reflected on Exhibit A-18 (NJH-8), line 8, column (i), actual activated carbon expenses for 2024 were $1.981 million, $0.211 million lower than projected.

Q. Why were activated carbon expenses lower than projected?

A. The 2024 activated carbon expense was lower than projected due to actual dollars/lb coming in about 4% less than forecast. Additionally, it was lower than projected due to the consumption of higher sulfur coal, which generally contains less mercury, and better management of the operating limits for mercury.

<u>2024 Base Load Power Plant Generating Cost Efficiency</u>

Q. Why was Exhibit A-17 (NJH-7) included in this filing?

A. This information was provided in response to the MPSC's Report on Status of Power Quality in Michigan in Case No. U-15945.

<u>Wind Asset Performance Data</u>

Q. Please describe Exhibit A-19 (NJH-9).

A. Exhibit A-19 (NJH-9) presents performance details regarding the Company's owned wind assets. The Commission's September 28, 2023 Order in Case No. U-20803 required this information to be included in future PSCR reconciliation proceedings. Specifically, Exhibit A-19 (NJH-9) includes the 2024 gross actual generation, the 2024 actual and target capacity factor, the 2024 actual and target time-based availability, and the 2024 lost potential MWh due to planned maintenance, repair maintenance, and regulatory curtailment.

Q. Please describe Gross Actual Energy reflected in Exhibit A-19 (NJH-9), column (b).

A. Gross Actual Energy is the gross volume of energy produced by a wind farm during a specific period. The Gross Actual Energy does not represent any adjustment for station power (amount of energy consumed by the wind farm during operations).

Q. Please describe capacity factor reflected in Exhibit A-19 (NJH-9), column (c).

A. Capacity factor is the measure of how often a generation unit operates during a specific period of time. Capacity factor is presented as a percentage and is calculated by dividing the actual unit generation output by the maximum possible generation output. The Company's target capacity factor is presented in Exhibit A-19 (NJH-9), column (d).

Q. Please describe time-based availability reflected in Exhibit A-19 (NJH-9), column (e).

A. Time-based availability is the measure of the hours when the turbine is available during a specific overall period of time. Time-based availability is presented as a percentage, and 97% is generally considered first quartile performance in the industry. Three of the Company's parks outperformed this high standard and one only narrowly missed this performance level. The Company's targeted time-based availability and actual availability is presented in Exhibit A-19 (NJH-9), column (f).

Q. Please describe any significant issues that affected a wind parks ability to meet time-based availability targets.

A. Time-based availability targets essentially allow for just one unit to be down before the Company is at risk for not meeting those targets. Gratiot and Crescent wind parks have both experienced issues with blade cracking, as well as a design defect with the blades that have caused significant downtime when the issue presents itself. The blade cracking and design defects have caused units to be shut down to avoid likely catastrophic failures. The units remain down until replacement blades can be procured and installed, which is a costly and timely process.

Q. Please describe potential lost energy for planned and repair maintenance reflected in Exhibit A-19 (NJH-9), columns (g) and (h).

A. The potential lost energy for planned and repair maintenance is a calculation of how much energy could have been generated during the periods in which the turbines were out of service. The energy loss is only hypothetical because the calculation assumes sufficient fuel (i.e. wind speed) would have been available for the turbines to operate during the time frame in which they were unavailable for planned and repair maintenance, which in reality would not always be true.

Q. Please describe lost energy for regulatory curtailment reflected in Exhibit A-19 (NJH-9), column (i).

A. Curtailment reflects the adjustment of the wind turbine blade angles (i.e. parallel to the wind) to slow them down or stop them from turning (also known as "idling"). Wildlife curtailment is implemented when the risk of collision is expected to be high for bird and bat migration through the turbine sweep area, resulting in a reduction in bird and bat collision fatalities. Icing curtailment may also be implemented for local special use permit compliance reasons. The last reason for curtailment is possible implementation for energy market reasons, this typically does not affect the Consumers Energy wind fleet, due to primary dispatch as a "must run" resource.

Q. What is your assessment of the performance of the Company's wind generation assets during 2024?

A. Overall, three out of the five Company wind assets exceeded their targeted time-based availability and, as a result, generated value for customers. Although the actual capacity factors fell short of target capacity factor, the wind generation fleet often exceeding its time-based availability target reflects the fact that the Company maintained its wind generation assets in a condition which would allow for creation of customer value.

<u>Ludington Replacement Power Costs</u>

Q. Please discuss Exhibit A-20 (NJH-10).

A. Earlier in this testimony, I discussed Ludington outages that were 28 days or greater in length and provided detail on work performed during those periods. While some of those outages (or portions of those outages) occurred as a result of defective, non-conforming, and incomplete work performed by TAES, some of the outages (or portions of the outages) were also conducted to complete other necessary work, and while down, TAES-related work was performed. If the outage would have occurred regardless of TAES-related defects, then the replacement power costs of the outage are not removed to the regulatory asset approved by the Commission in Case No. U-21310 even if some ancillary TAES-related work was completed. Conversely, Exhibit A-20 (NJH-10) presents only the Ludington outages and associated replacement power costs for work that would not have occurred but for the defective, non-conforming, and incomplete work performed by TAES. The Company has removed replacement power expenses associated with these outages from this reconciliation and has recorded these replacement power costs in the regulatory asset approved by the Commission in Case No. U-21310. Specifically, this order approved the joint application of Consumers Energy and DTE for cost deferral accounting and a regulatory asset for the costs incurred to remediate the defective work performed by TAES. In total, the Company has recorded into the regulatory asset account $243,441 of replacement power costs incurred in 2024 as a result of defective, non-conforming, and incomplete TAES work. Company witnesses Feazel and Raymond T. Scaife reflect the removal of these replacement power costs in their direct testimony and exhibits.

Q. How did the Company identify Ludington unit outages that occurred as a result of defective work performed by TAES?

A. The Company documents outages on the Ludington units and reports the outage information to GADS. To identify whether the outage should be evaluated for replacement power costs, the Company reviews the cause of the outage and the work performed. If the outage was associated with required inspections and/or repairs of equipment which was subject to issues with TAES' incomplete, non-conforming, and defective work, only the portion of the outage that is attributed to TAES and the associated replacement power costs are removed from this case to the regulatory asset approved by the Commission in Case No. U-21310. More specifically, where an outage was both for normal inspections or maintenance and TAES-related work, in evaluating the cause of the outage and/or the work performed, the Company considers whether the scope of normal planned maintenance activities has increased and resulted in extending normal maintenance outages.

Conclusion

Q. Please provide a conclusion of your testimony.

A. My testimony described certain outages experienced in 2024 at the Company's fossil-fueled electric generating units and the Ludington Pumped Storage Plant, explained the expense associated with emission allowances for oxides of nitrogen and sulfur dioxide, and explained the expense associated with the consumption of urea, aqueous ammonia, lime, and activated carbon. All generator outages were performed in a reasonable and prudent manner on the part of Consumers Energy. All expenses associated with emissions allowances and consumption of urea, aqueous ammonia, lime, and activated carbon were incurred in a reasonable and prudent manner. Finally, the Company's time-based availability for its wind generation fleet continued to provide value for its customers.

Q. Does this conclude your direct testimony?

A. Yes.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21424
Exhibit No.: A-15 (NJH-5)

Witness: NJHoffman
Date: March 2025

GENERATION PERFORMANCE STATISTICS
JANUARY 1, 2024 TO DECEMBER 31, 2024

Line No.	(a)	(b)	(c)	(d)	(e)
	Unit	Unit Availability	MWh Availability	Periodic Factor	Random Outage Rate
1	Campbell 1	81.49%	77.03%	9.55%	14.84%
2	Campbell 2	54.33%	51.93%	0.00%	48.07%
3	Campbell 3 (CE)	83.38%	80.75%	0.00%	19.25%
4	Karn 3	83.01%	74.53%	14.81%	12.51%
5	Karn 4	77.62%	76.32%	16.66%	8.42%
6	Zeeland Simple Cycle	91.96%	91.40%	4.71%	4.08%
7	Zeeland Combined Cycle	84.95%	84.62%	14.38%	1.17%
8	Jackson CC	94.77%	88.61%	5.12%	6.61%
9	Covert CC	80.66%	78.09%	3.79%	18.83%
10	Total Fossil CE[1]	82.89%	78.99%	6.55%	15.47%
11	Base Load Fossil CE	73.07%	73.18%	3.19%	24.41%
12	Ludington 1-6	82.49%	82.50%	10.97%	7.33%
13	Total Hydro	50.75%	47.71%	10.30%	46.81%

[1] Does not include Karn 3 and Karn 4.

Report Period: January 2024 to December 2024

Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
CAMPBELL 1-2 - CAMPBELL 1							
35	U1	2/23/2024 12:24	2/23/2024 12:46	4460	turbine overspeed testing	0.37	95.33
38	U1	2/27/2024 0:01	3/1/2024 0:01	4293	gov valve work	72	18720
39	PO	3/1/2024 0:01	3/31/2024 0:00	4293	gov valve work	718.98	186935.67
41	PE	3/31/2024 0:00	4/5/2024 0:00	4293	gov valve work, continued	120	31200
74	U1	8/25/2024 13:05	9/3/2024 20:07	3499	1C Feeder Issue > 20MW load swings > maxed on FW > FW runback > unit trip	223.03	57988.67
88	U1	10/11/2024 6:29	10/31/2024 17:42	1040	SH tube leak, unit offline	491.22	127716.34
CAMPBELL 1-2 - CAMPBELL 2							
1	U1	1/1/2024 0:00	2/29/2024 0:36	3401	SUBFP failure.	1416.6	396648
2	U1	2/29/2024 8:31	3/1/2024 3:00	3499	Low FW flow when transitioning from SUBFP to MBFP.	18.48	5175.33
3	SF	3/1/2024 3:00	4/10/2024 22:59	4293	Gov valve controller not engaging properly.	978.98	274115.34
16	U1	4/26/2024 13:43	5/7/2024 3:30	4291	Circuit oil cooler leak (water into the oil)	253.78	71059.33
21	U1	5/10/2024 6:59	5/30/2024 5:30	4299	Turbine valve issue, closed unexpectedly and boiler overpressure. Unit trip.	478.52	133984.67
26	U1	6/5/2024 15:54	6/14/2024 4:04	4291	Circuit oil cooler leak (water into the oil)	204.17	57166.67
64	U1	8/21/2024 0:47	8/28/2024 6:29	4302	leak on thrust oil protective trip device.	173.7	48636
73	U1	10/1/2024 20:16	10/11/2024 2:16	1488	FO: 2B SAH issue + L.turb throttle valve steam leak	222	62160
77	U1	11/1/2024 22:54	11/12/2024 23:29	640	U2 FO to address 201A & 210 valves	265.58	74363.34
CAMPBELL 3 - CAMPBELL 3							
43	MO	4/12/2024 13:18	4/27/2024 9:18	1000	Maintenance outage to repair tube leak.	356	302030.41
47	U1	4/27/2024 9:18	6/12/2024 9:04	4410	Turbine Turning Gear failure.	1103.77	934414.98
COVERT GENERATING STATION - COVERT UNIT 1							
6	MO	2/9/2024 7:59	2/12/2024 0:00	3210	Circ Pump Replacement	64.02	25606.67
7	PO	2/12/2024 0:00	2/14/2024 17:29	3210	Circ Pump Replacement	65.48	26193.33
10	U1	3/20/2024 8:30	3/31/2024 19:35	6011	Tube rupture confirmed	275.08	105329.41
11	PO	5/5/2024 0:35	5/11/2024 1:57	3210	Replace 1A Circ Pump	145.37	55660.9
12	U1	5/11/2024 2:19	5/11/2024 4:27	3830	Aux Boiler tripped on low water level, reset and restarted	2.13	816.85
13	U1	5/11/2024 11:48	5/11/2024 15:33	3849	Air line seperated causing low instrument air pressure	3.75	1435.88
17	U1	7/9/2024 20:25	7/13/2024 7:50	9603	Suspected Fuel Gas out of compliance	83.42	30263.56
18	U1	7/23/2024 19:23	7/28/2024 7:26	9623	Removed from service due to high PM Tests	108.05	39200.54
19	U1	7/29/2024 20:23	7/30/2024 12:35	6163	Corrected 1HRS-PV105	16.2	5877.36
33	MO	9/28/2024 0:26	10/7/2024 1:28	4499	Steam Turbine Valve Work	217.03	79716.34
34	U1	10/16/2024 13:04	10/16/2024 16:38	5049	Loss of fuel pressure due to pigging	3.57	1310.04
35	U1	12/12/2024 11:36	12/12/2024 13:08	1799	IP Drum Level Transmitter failed due to being frozen	1.53	613.33
37	PO	12/19/2024 0:27	12/21/2024 2:36	1700	Repair 1FWS-FV131 HP FWR Reg VLV	50.15	20060

INFORMATION FOR UNIT - Campbell Unit 3
PERIODIC OUTAGE

Sequence Number:	Campbell Unit 3-2024-47
Plant/Unit:	Campbell Unit 3
MW Derate:	
Event Year:	2024
Event Number:	47
Start Date:	4/27/2024 9:18
End Date:	6/12/2024 9:04
Outage Type:	U1
Duration (Hours):	1,103.8
MWh Loss:	936,162.6
NERC Cause Code:	4410
NERC Cause Code Description:	Turning gear and motor
Root Cause Description:	Unit unable to operate due to failure of the turbine turning gears
Event Description:	Turbine Turning Gear failure.
Additional Description:	Turning gear failed on startup. Teeth in the planetary gear assembly were found to have sheared off.
Mode of Failure:	Gear failure
Final Corrective Action:	Fabricate and install new replacment gear components
Mechanism Causing:	Preliminary metallurgical examination of the gears were inconclusive due to the level of damage that the gears experienced.
Final Root Cause	Inconclusive, but assumed cyclic fatigue. Turning gear assembly was last inspected in 2016 (with no findings).
Scope to Correct Root Cause:	Fabricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025.
Additional Scope:	N/A
If outage Extended for Additional Work & Why:	N/A

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21424
Exhibit No.: A-16 (NJH-6)
Page: 1 of 1
Witness: NJHoffman
Date: March 2025

COMPARISON OF CONSUMERS ENERGY AND GADS AVERAGES FOR SIMILAR UNITS
EQUIVALENT AVAILABILITY

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
		GADS AVERAGES		CONSUMERS ENERGY		CE VERSUS
	UNIT	2017-2023	2023	2020-2024	2024	GADS **
1	Campbell 1	78.47%	76.14%	73.10%	77.03%	Higher
2	Campbell 2	74.74%	73.97%	52.82%	51.93%	Lower
3	Campbell 3	78.41%	78.43%	76.94%	80.75%	Higher

** Higher indicates one-year and/or five-year were higher than the GADs average.
Lower indicates both tests were lower than the GADS average.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 16

DOE Letter to FERC

Department of Energy
Washington, DC 20585

June 13, 2025

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Referral to the Federal Energy Regulatory Commission; ER25-__

Dear Secretary Reese:

By this letter and the accompanying enclosure, the Department of Energy (DOE) refers to the Federal Energy Regulatory Commission (Commission) certain matters for resolution, pursuant to 10 C.F.R. § 205.376. DOE requests that the Commission conduct such proceedings as it determines to be appropriate and issue a final order resolving the rate issues as discussed below.

On May 23, 2025, the Secretary of Energy, pursuant to the authority vested in him by section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), and section 301 of the DOE Organization Act, 42 U.S.C. § 7151(b), issued Order No. 202-25-3 ("May 23, 2025 Order). In the May 23, 2025 Order, the Secretary determined that an emergency existed in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance would meet the emergency and serve the public interest.

Pursuant to the May 23, 2025 Order, the Secretary directed the Midcontinent Independent System Operator (MISO) and Consumers Energy (Consumers) to "take all measures necessary to ensure that the [J.H.] Campbell Plant is available to operate" during the period that the Order is in effect and directed MISO to "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The May 23, 2025 Order further states that "Consumers is directed to file with the Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c)." Because the May 23, 2025 Order is predicated on the shortage of facilities for the generation of electric energy and other causes, such as resource adequacy concerns, the Campbell plant shall not be counted as a capacity resource.

Section 202(c) of the Federal Power Act states as follows:

> If the parties affected by [an emergency order issued pursuant to section 202(c)] fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

DOE's regulations concerning generation of electricity to alleviate an emergency shortage of electric power address the procedures that DOE will follow when relevant entities are not able to agree on the rate issues as a result of an order issued by DOE pursuant to section 202(c) of the Federal Power Act:

> The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event DOE determines that an emergency exists under section 202(c), and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures. 10 C.F.R. § 205.376.

On June 10, 2025, DOE received a letter from counsel for Consumers which stated that MISO and Consumers have not been able to reach agreement on the rate issues relating to the May 23, 2025 Order.

Consumers and MISO have not been able to agree on appropriate rate issues relating to DOE Order No. 202-25-3. DOE hereby refers only the rate issues to the Commission pursuant to 10 C.F.R. § 205.376.

DOE is not referring to the Commission any other matters, including, but not limited to, DOE's finding of an emergency, the prescription of conditions of service, or any other matter arising from DOE's exercise of its authority under section 202(c).

Sincerely,

Holly Rachel Smith
Deputy General Counsel
for Compliance

Enclosure

cc: Shaun M. Johnson, Esq.
General Counsel and Senior Vice President, Business Optimization
Consumers Energy Company

John R. Bear
President and Chief Executive Officer
Midcontinent Independent System Operator, Inc.

David Morenoff, Esq.
Acting General Counsel
Federal Energy Regulatory Commission

The Honorable Mark Christie
Chairman
Federal Energy Regulatory Commission

The Honorable David Rosner
Commissioner
Federal Energy Regulatory Commission

The Honorable Lindsay S. See
Commissioner
Federal Energy Regulatory Commission

The Honorable Judy W. Chang
Commissioner
Federal Energy Regulatory Commission

The Honorable Dan Scripps
Chairman
Michigan Public Service Commission

The Honorable Katherine Peretick
Commissioner
Michigan Public Service Commission

The Honorable Alessandra Carreon
Commissioner
Michigan Public Service Commission

The Honorable Dana Nessel, Esq.
Attorney General
State of Michigan

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

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[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id*.
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.

Chris Wright
Secretary of Energy

cc: **<u>FERC Commissioners</u>**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

<u>Michigan Public Service Commissioners</u>
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

Document Content(s)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 17

DOE Order No. 202-20-2

Department of Energy
Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-7
Independent System Operator	)	
(MISO)	)	
	)	

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 18

Proudfoot Rebuttal Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and other relief.

Case No. U-21090

Volume 10

_______________________________________/

CROSS-EXAMINATION (Settlement Agreement)

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Friday, May 20, 2022, at 9:06 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
MICHAEL C. RAMPE, ESQ.
Consumers Energy Company
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On behalf of Consumers Energy Company

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On behalf of Biomass Merchant Plants (BMPs)

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Lansing, Michigan 48909

On behalf of Michigan Attorney General

(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

REBUTTAL TESTIMONY OF

PAUL PROUDFOOT

IN SUPPORT OF THE SETTLEMENT AGREEMENT

MICHIGAN PUBLIC SERVICE COMMISSION

May 13, 2022

REBUTTAL TESTIMONY OF PAUL PROUDFOOT IN SUPPORT OF THE SETTLEMENT AGREEMENT
CASE NUMBER U-21090

Q. Would you please state your name and business address for the record?

A. My name is Paul Proudfoot. My business address is 7109 West Saginaw Hwy, Lansing, Michigan 48917. I am currently working remotely from my home.

Q. By whom are you employed and what is your position?

A. I am employed by the Michigan Public Service Commission (MPSC or Commission) as the Director of the Energy Resources Division.

Q. Are you the same Paul Proudfoot that filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. To respond to Energy Michigan, Inc. witness Alexander J. Zakem's and Wolverine Power Supply Cooperative, Inc. witness Thomas King's direct testimony filed May 9, 2022 in opposition to the Settlement Agreement (SA) and consider the contested settlement under the factors set forth in Rule 431 (5)(b) and (c).

Q. Are you going to rebut each argument in witness Zakem's and witness King's respective direct testimony?

A. No. MPSC Staff (Staff) opines that the record in this case is substantial enough to support Staff's position on several of these items and these positions have been carried through to the SA. Staff's decisions not to address an issue in rebuttal should not be assumed to be agreement with the positions of other parties contesting the SA.

COMPETITIVE SOLICITATION

Q. Do you agree with Energy Michigan, Inc. witness Zakem's critique of Consumer Energy Company's (Consumers or the Company's) resource acquisition methodology pursuant to Subsection 6.b.i. of the Settlement Agreement?

A. No. Mr. Zakem is concerned that the Settlement Agreement (Subsection 6.b.i.) does not require that the 500 Zonal Resource Credits (ZRCs) be new resources and could result in sourcing resources that are already counted in the Midcontinent Independent System Operator (MISO) Zone 7's resource adequacy and that the Commission should assess the effects of the Integrated Resource Plan (IRP) on all Michigan residents and not just Consumers ratepayers. While Staff made a similar argument in testimony concerning the preferred course of action (PCA) the Company initially proposed, Mr. Zakem fails to recognize that Subsection 6.b.1. does not require the 500 ZRCs to be pre-existing (already counted towards MISO Zone 7 resource adequacy). In accordance with the terms of the Settlement Agreement, these resources will be competitively sourced. In addition, respondents to the solicitation could be from some of the projects currently in the MISO Queue (ITC Transmission, Michigan only) that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3.[1] Therefore, between existing projects and the intermittent and dispatchable projects in the MISO Queue, there is opportunity to add new capacity within MISO Zone 7.

Q. Does Staff believe that Subsection 6.b.1 of the Settlement Agreement, when read as a whole, balances the interests of the Company and MISO Zone 7?

A. In preparation for its IRP filing, the Company had conducted a request for proposal (RFP) that ultimately resulted in resources which were included in its filed PCA. That RFP specifically required pre-existing gas resources within the Zone. In contrast, as discussed above, the Company is now requesting dispatchable, non-intermittent resources (not specifically gas) with no requirement to be pre-existing. In addition, Subsection 6.b.1.ii

[1] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/

also partially addresses Mr. Zakem's concerns. Subsection 6.b.1.ii provides for a second tranche in which the Company will request 200 ZRCs from unaffiliated third parties via Power Purchase Agreements (PPAs) for intermittent and dispatchable resources. Between the two tranches, the Settlement Agreement provides the opportunity for a wide variety of new resources to bid in and ultimately be built within MISO Zone 7, such as the wind, solar, battery storage, or gas resources currently in the MISO Queue Study Phases and not just pre-existing resources.

RESOURCE ADEQUACY

Q. Energy Michigan and Wolverine both object to the SA, in part, because of the impacts on resource adequacy. Does Staff share these same concerns about the SA?

A. No. The SA is reasonable and is a resource adequacy improvement over the Company's original PCA. The key resource adequacy difference between the Company's PCA and the SA is that the Company has agreed to delay the retirement of Karn Units 3 & 4. According to the terms of the SA, Karn Units 3 & 4 will retire on or be before May 31, 2031, while the original PCA called for the retirement of Karn Units 3 & 4 by May 31, 2023.

Q. Why is this a key difference?

A. The Company was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7 (Zone 7). The SA only retires a portion of that amount, approximately 1500 MW, with the commitment to retire all Campbell Units by 2025. Concurrently, in the SA, the Company is proposing to add approximately 1176 MW to Zone 7 through the acquisition of the Covert Power Plant. Although Covert is an existing plant, it is currently within the PJM Interconnection (PJM). In addition, the Company continues its solar build out and is expected to add 300 MW of solar resources in 2023, 500 MW of solar resources in 2024, and 500 MW of solar resources in 2025.[2,3] Under the current MISO construct, that is approximately 400 ZRC's of new resources within MISO Zone 7.

Q. Do these resource additions that you describe include the Company's one-time solicitation for 700 MW outlined in the SA?

A. No. The one-time solicitation is in addition to the resources discussed above.

Q. Does Staff agree with Wolverine witness King that the Company is likely to be short on capacity in 2025?

A. No. Staff does not believe the SA is likely to result in the Company being short on capacity in 2025. Karn Units 3 & 4 represent approximately 760 MW of unforced capacity.[4] This is more than 300 MW above the amount of capacity the Company assumed from the CMS units (DIG, Livingston, & Kalamazoo) in 2025. Additionally, beyond Karn Units 3 & 4 and the solar resources being added by 2025, the one-time solicitation for 700 MW discussed above is an opportunity for the Company to procure additional capacity for 2025.

Q. Does Staff agree with Wolverine witness King that the 7.4% reserve margin used by the Company in its Capacity Demonstration in Case No: U-21099 is unreasonable?

A. No. The reserve margin used by the Company in its capacity demonstration for 2025 comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report.[5] It is also worth noting that assuming a constant reserve margin of 8.7% instead of 7.4% would represent about 100 MW of additional obligation to the Company. The differences

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[2] Case No. U-20165, Company Exhibit A-20.
[3] Case No. U-21090, Company Exhibit A-14, p. 9.
[4] Prefiled Direct Testimony of Company witness Richard Blumenstock, p. 53.
[5] https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf, p. 26.

between Karn Units 3 & 4 and the CMS capacity is still likely enough to cover this difference, even without counting any additional capacity from the one-time solicitation.

Q. Does the Settlement Agreement provide other opportunities to support MISO Zone 7 resource adequacy?

A. In addition to the Covert Power Plant acquisition, as alluded to above, the Company intends to continue its annual solar solicitations, building approximately 8000 MW by 2040.

RULE 431 SETTLEMENT AGREEMENT CONSIDERATIONS

Q. Does Staff believe that all parties have been given reasonable opportunity to present evidence and arguments in opposition to the SA?

A. It is Staff's opinion that all parties have been given an opportunity to present arguments in opposition to the SA. In addition to any opportunities the parties had to comment on proposed Settlement Agreement terms during negotiations, the Commission has given parties an opportunity to file direct and rebuttal testimony for and against the SA, and the Commission has set dates for another hearing and briefing on the SA to present evidence and arguments.

Q. Is it Staff's position that the public interest is adequately represented by the parties who entered the settlement agreement?

A. Staff believes that Consumers has adequately met its requirements under PA 341 of 2016, as stated above, and provided a reasonable revised PCA. Not only did the Company and Staff sign the SA, but many other parties also signed who represent residential customers (the Attorney General, CUB, and Urban Core Collective); commercial and industrial customers (Hemlock, MCV, and MPPA); businesses in Michigan's advanced energy sector (MEIBC); environmental groups (MEC, NRDC, SC, ELPC, Vote Solar, Ecology Center, and Union of Concerned Scientists); a transmission company (METC); and third-party developers (GLREA). Staff opines that the signatories to the SA represent most, if not all, of Michigan's sectors concerned with the future of energy related issues. In addition, Residential Customer Group and ABATE filed letters of non-objection.

Q. Is it Staff's position that the settlement is supported by substantial evidence in the record as a whole?

A. Yes. As stated above, the record in this case is substantial. All issues addressed in the SA have been addressed in testimony, rebuttal, brief, exceptions, and robust discovery. The SA was filed after a full record had been developed in this case. Therefore, based on all of the above, it is Staff's opinion that this SA meets the requirements of Rule 431.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 19

Walz Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.

Case No. U-21090

Volume 3

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CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Wednesday, December 1, 2021, at 9:15 a.m.

APPEARANCES:

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Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

REVISED DIRECT TESTIMONY

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

SECTION I: INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Sara T. Walz, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

Q. By whom are you employed?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

Q. What is your position with the Company?

A. I am ~~a Principal Engineering Technical Analyst Lead in the Integrated Resource Planning Section~~ the Manager of Integrated Resource Planning of the Electric Grid Integration Department.

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Mathematics in 2006 from Michigan State University and a Master of Science degree in Applied Mathematics in 2007 from North Carolina State University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2008. I was responsible for the Financial Transmission Rights monthly and annual allocation and auction. In September 2009, I began working in the Production Cost Modeling area of Transactions and Resource Planning, where I served as the primary modeler and subject matter expert witness for near-term fuel and purchased power expenses using the PROMOD production cost modeling software until May 2017. I was involved in the Strategist modeling performed for the Company's application of a certificate of necessity to build the Thetford generating plant in 2013, Michigan Public Service Commission

("MPSC" or the "Commission") Case No. U-17429. That case was ultimately withdrawn from the Commission's review in lieu of the purchase of the Jackson generating plant. In May 2017, I assumed the position of lead of the modeling team now referred to as "IRP Modeling and Analytics"; my responsibilities have included leading the team to complete modeling and support of the 2018 Integrated Resource Plan ("IRP") – the Company's first IRP filed under new state law.

Q. What are your present responsibilities and duties as a Principal Engineering Technical Analyst Lead?

A. Presently I am responsible for all long-term capacity expansion and production cost modeling used to inform the Company's long-term electric supply strategy decisions. My team and I utilize Energy Exemplar's Aurora software platform ("Aurora") to perform all aforementioned modeling.

Q. Have you provided testimony before the Commission ?

A. Yes, I provided testimony in the following MPSC cases on behalf of the Company:

- U-17095, the Company's 2013 Power Supply Cost Recovery ("PSCR") Plan;
- U-17095R, the Company's 2013 PSCR Reconciliation;
- U-17317, the Company's 2014 PSCR Plan;
- U-17317R, the Company's 2014 PSCR Reconciliation;
- U-17678, the Company's 2015 PSCR Plan;
- U-17678R, the Company's 2015 PSCR Reconciliation;
- U-17918, the Company's 2016 PSCR Plan;
- U-17918R, the Company's 2016 PSCR Reconciliation;
- U-18142, the Company's 2017 PSCR Plan case; and

- U-20165, the Company's 2018 IRP.

SECTION II: PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support the Company's IRP and:

- Identify and describe the scenarios and sensitivities evaluated and presented in this IRP;
- Describe the planning and modeling process that was performed in support of this IRP;
- Discuss the design and results of the retirement analysis included in this IRP;
- Describe the resource options considered in the IRP analysis;
- Support the selection of the types of resources included in the Company's Proposed Course of Action ("PCA");
- Discuss the Company's Capacity Sufficiency Analysis ("CSA") to determine the potential for loss of load events;
- Describe how demand-side management programs were designed to be offered into the Aurora optimization simulations;
- Discuss modeling performed specific to existing natural gas assets for which the Company requests approval, as part of its PCA; and
- Present the results of the IRP and CSA modeling and provide interpretation of the economic and statistical results that informed development of the PCA.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits, all of which were prepared by me or under my supervision:

Exhibit A-4 (STW-1)	2021 IRP MPSC-Required Scenarios and Sensitivities;
Exhibit A-5 (STW-2)	2021 IRP Consumers Energy Scenarios and Sensitivities;
Exhibit A-6 (STW-3)	2021 IRP Existing Assets Zonal Resource Credits and Projected Generation;

Exhibit A-7 (STW-4)	2021 IRP Levelized Cost of Energy – Resource Screening;
Exhibit A-8 (STW-5)	2021 IRP MISO Market Topology;
Exhibit A-9 (STW-6)	2021 IRP Economic Benefits of CVR and EWR;
Exhibit A-10 (STW-7)	2021 IRP Demand Response Resource Blocks, by Scenario, for Aurora;
Exhibit A-11 (STW-8)	2021 IRP Portfolio Design;
Exhibit A-12 (STW-9)	2021 IRP Aurora NPV Results;
Exhibit A-13 (STW-10)	2021 IRP Aurora Resource Selections, by New Technology Resource;
Exhibit A-14 (STW-11)	2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan;
Exhibit A-15 (STW-12)	2021 IRP Purchased Gas Units Operations;
Exhibit A-16 (STW-13)	2021 IRP Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable;
Exhibit A-17 (STW-14)	2021 IRP Capacity Sufficiency Analysis Loss of Load Event Examples: Controllable Generation;
Exhibit A-18 (STW-15)	2021 IRP Capacity Sufficiency Analysis Results: Heat Maps;
Exhibit A-19 (STW-16)	2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary; and
Exhibit A-20 (STW-17)	2021 IRP Total Fuel Cost of Existing Owned Units, by Scenario.

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

A. The remainder of my direct testimony is organized in sections as follows:

SECTION III: SUMMARY

SECTION IV: SCENARIO AND SENSITIVITY DEVELOPMENT

SECTION V: PROCESS USED IN MODELING

SECTION VI: RESOURCE OPTIONS CONSIDERED IN THE IRP

SECTION VII: DEVELOPMENT OF DEMAND-SIDE OPTIONS FOR AURORA

SECTION VIII: OPTIMIZATION PORTFOLIOS

SECTION IX: PURCHASED GAS UNIT OPERATIONS

SECTION X: SUMMARY OF MODELING RESULTS

SECTION XI: CAPACITY SUFFICIENCY ANALYSIS

SECTION XII: CAPITAL, O&M, AND FUEL COST SUMMARY

SECTION III: SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony will provide the quantitative support for the PCA, discussed in the direct testimony of Company witness Richard T. Blumenstock, that was developed based on the lowest-cost resources selected from the hundreds of resource optimizations developed as part of this IRP.

I will show that the PCA was developed based on the resources chosen by computer optimization models that select the least-cost portfolio of resources available. The outputs of the model highlight the types of resources that provide the lowest cost to customers to meet resource planning requirements. As will be discussed later in my direct testimony, the scenario and sensitivity modeling ultimately led the Company to select a portfolio of resources for its PCA that includes the purchase of existing natural gas resources as well as large amounts of solar, with lesser amounts of Demand Response ("DR") and battery storage resources providing a balanced portfolio. Additional information regarding development of the PCA, based on model optimization results, can be found in the Summary of Modeling Results found at Section X of this direct testimony.

The development of this IRP includes thorough application of a variety of resource, operational, cost, and environmental inputs and data into computer-based models that developed short- and long-term resource plans. My direct testimony will demonstrate that the modeling process used to develop the IRP included in this filing was rigorous and comprehensive, consistent with good utility practice, followed the requirements detailed in Section 6t of Public Act 341 of 2016 ("Act 341"), and ultimately was used to identify the key elements of the best IRP for Michigan for both short-term and long-term planning periods.

Finally, my direct testimony will provide economic support of the Company's plans to exit coal within the next five years, invest in existing baseload generation resources to ensure electric supply reliability, invest in the growth of demand-side resources, and continue on the Company's clean energy plan of increasing levels of renewable energy resources over the next twenty years. My sponsored exhibits will also provide the economic support for the decision to retire the natural gas and oil-fired D.E. Karn ("Karn") Units 3 and 4 generating units, and the coal-fired J.H. Campbell ("Campbell") Units 1, 2 and 3 generating units. The investments identified in this IRP are part of the Company's PCA to provide near-term and long-term capacity to fulfill the needs of our customers.

SECTION IV: SCENARIO AND SENSITIVITY DEVELOPMENT

Q. What scenarios were included in the development of the modeling used in the IRP?

A. The scenarios and sensitivities modeled in the Company's IRP include the following:

- Scenarios defined within the Michigan Integrated Resource Planning Parameters ("MIRPP"), which were adopted by the Commission in Case No. U-18418 pursuant to Act 341, Section 6t. These major input assumptions are summarized in Exhibit A-4 (STW-1);

- The "Carbon Reduction Scenario," an additional scenario developed by the MPSC was order on February 18, 2021 in Case No. U-20633, which contemplates increases in electrification of various industries, including increases in electric vehicle ("EV") adoption and corresponding increases in customer demand – in combination with carbon reduction targets issued in Michigan Governor Gretchen Whitmer's executive directive ED 2020-10. This scenario is also included in Exhibit A-4 (STW-1); and

- Scenarios developed by the Company, which are largely created with the primary purpose of performing retirement analysis as required in the Settlement Agreement in Case No. U-20165 (the Company's 2018 IRP). These major input assumptions are summarized in Exhibit A-5 (STW-2).

Q. What sensitivities were included in the development of the modeling used in the IRP?

A. Thirteen sensitivities were required for the MIRPP scenarios, including the evaluation of impacts resulting from changes to the following assumptions: demand growth, increased energy efficiency (also identified as Energy Waste Reduction ("EWR")), the price of natural gas, return of customers to the utility currently taking service from alternative energy suppliers, higher carbon regulations, higher renewable portfolio standards, and, finally, a portfolio optimization that allows only combustion turbines to meet future customer needs. The Consumers Energy scenarios include 39 retirement sensitivities, as well as a number of additional sensitivities evaluating the impacts from changes to several input assumptions including EWR, Conservation Voltage Reduction ("CVR"), behind-the-meter-generation levels ("BTMG"), the effective load carrying capability ("ELCC") of solar, costs of projected transmission network upgrades, and the assumed discount rate.

Q. Please further describe the scenarios included in this IRP.

A. Under scenarios currently defined under MIRPP, three base case scenarios were evaluated: (i) a Business as Usual ("BAU") scenario, which is consistent with many of the Company's major assumptions such as customer demand, EWR, DR, cost of capital for new resource technologies, environmental regulations, and more; (ii) an Emerging Technologies ("ET") scenario, which assumes advancements in technologies and economies of scale that result in greater potential for DR, EWR, and other emerging technologies; and (iii) an Environmental Policy ("EP") scenario, which targets carbon reductions of 30% from 2005 to 2030. (See Exhibit A-4 (STW-1). In this scenario, it is assumed that renewable portfolio standards and goals are raised and that DR and EWR programs grow.

The fourth scenario, or the Carbon Reduction Scenario, is evaluated under EP input assumptions but assumes load growth at 1.5% year-over-year throughout the study period, to represent increased electrification in the energy sector as well as a 28% and 32% reduction in carbon emissions by 2025, compared to 2005 levels. (See Exhibit A-4 (STW-1). This scenario requires inclusion of the Company's PCA as the selected expansion plan; however, due to the increasing load growth – and corresponding increases in the Planning Reserve Margin Requirement ("PRMR") – additional resources must be selected in this scenario.

For the first three Consumers Energy scenarios, the majority of input assumptions match those of the BAU, ET, and EP scenarios, described above, with the exception of two input variables modified: 1) the assumed cost of natural gas; and 2) the levels of EWR included in the underlying load forecast. (See Exhibit A-5 (STW-2). The fourth Consumers Energy scenario reflects a collection of the Company's own assumptions under what is referred to as an Advanced Technologies ("AT") scenario. (See Exhibit A-5 (STW-2). This scenario represents a future in which advancements in electrified transportation drive acceleration of clean energy and creates a higher penetration of distributed energy resources. In the AT scenario, customer engagement in energy sources and consumption is assumed to increase, driving higher levels of EWR and behind-the-meter generation, either at the residential, commercial, or industrial customer levels. This collection of assumed changes in electric consumption result in a flat to declining load forecast. Other differences in this scenario include changes to capital cost forecasts of new resource technologies, natural gas price forecast, and changes to the makeup of the remainder of the regional energy market resources.

We have abbreviated the names of the eight base scenarios as follows:

1. BAU AEO – BAU, using natural gas prices from the U.S. Energy Information Administration's ("EIA") 2020 Annual Energy Outlook ("AEO") reference case, as required in the MIRPP;
2. EP AEO – EP, using natural gas prices from the EIA's 2020 AEO reference case, as required in the MIRPP;
3. ET AEO – ET, using natural gas prices from the EIA's 2020 AEO reference case, as required in the MIRPP;
4. CO_2 Reduction – this has underlying assumptions like the EP AEO, but with 1.5% load growth, CO_2 reduction targets by 2025 and the PCA as the basis of the new resource expansion plan;
5. BAU CE – BAU[1], using Consumers Energy's natural gas price projections;
6. EP CE – EP, using Consumers Energy's natural gas price projections;
7. ET CE – ET, using Consumers Energy's natural gas price projections; and
8. AT, using the EIA's 2020 AEO high gas and oil supply case.

Q. Why were the three Consumers Energy natural gas scenarios, using Consumers Energy's natural gas price projections, developed?

A. The MIRPP requires that "[n]atural gas prices utilized are consistent with business as usual projections as projected in the [EIA's] most recent [AEO] reference case." The Company has developed the Commission-required scenarios, using natural gas prices from the EIA's 2020 AEO. Those prices deviate materially from the Company's assumptions regarding

[1] References to "CE" in modeling scenarios are related to Consumers Energy's projections. BAU CE, EP CE, and ET CE scenarios are collectively referred to as "Consumers Energy scenarios" or "Consumers Energy gas scenarios."

gas price outlooks. See the direct testimony and exhibits of Company witness Brian D. Gallaway for additional details regarding the Company's projected natural gas prices versus the EIA 2020 AEO outlook.

As explained in the direct testimony of Company witness Blumenstock, one of the core objectives of the IRP is to determine appropriate retirement dates for the Company's existing fossil-fueled generating units. The Company believes it was most prudent to complete those evaluations using its own assumptions regarding future natural gas prices; therefore, the three scenarios, BAU CE gas, ET CE gas, and EP CE gas were created for the primary purpose of carrying out the retirement analysis. It should be noted that the retirement decisions are considered across a range of natural gas prices: 25% below the Consumers Energy gas price forecast, 25% above the Consumers Energy gas price forecast, and 50% above the Consumers Energy gas price forecast. Under this methodology of gas price risk evaluation, the Company ensures any decision regarding accelerated retirement of existing fossil-fuel generating units is considered under a wide range of future gas price outcomes – *including* the AEO gas price forecasts required in the AEO scenarios. See Figure 1 of this direct testimony.

Q. Why was the AT scenario developed?

A. The AT scenario was developed to consider a future in which increased customer engagement in energy sources and consumption drive increases in both customer-supplied generation (such as BTMG), and customer adoption of demand-side management ("DSM") programs (such as EWR). Specifically, an EIA forecast[2] of BTMG growth was included as a fixed resource to supply energy and capacity, and a transformational EWR outlook

[2] The BTMG forecast was based on EIA's 2020 Annual Energy Outlook (Low Cost Renewables case) of PV Generation Forecast (Residential – Table 21 and Commercial – Table 22) for the East North Central region.

was assumed, with levels remaining at 2% cumulative of prior year sales year-over-year. Higher levels of EWR and BTMG have the net impact of reducing the amount of energy and capacity the Company would expect to serve – a lower PRMR, and a net load shape that could flatten throughout the day.

On the other hand, the AT scenario contemplated increases in electrification, including EV adoption. An assumption of a 31% increase in EV adoption was considered, over the duration of the study period, which would result in increases in customer demand, likely during off-peak periods.

Q. How does the AT scenario differ from the three Consumers Energy scenarios (BAU CE, ET CE, and EP CE)?

The AT scenario differed from other Consumers Energy scenarios in the following ways: (i) natural gas prices were based in the EIA's 2020 AEO High Gas/Oil Supply case, which assumes natural gas prices are depressed, compared to the EIA Reference case; (ii) expansion of distributed energy resources is considered, with capital cost reductions assumed – capital costs for storage was assumed to decline to 50% below BAU by the end of the study period and distribution-connected solar is modeled at a 50% reduction compared to BAU; (iii) capital costs of transmission-connected solar was assumed at 35% below BAU; and (iv) lastly, a modeling methodology was considered in AT, in which, for non-Consumers Energy thermal generating units[3], the Aurora long-term capacity expansion simulations were allowed to economically retire units in advance of their current planned retirement dates. The methodology is referred to as "CanDrop" in Aurora.

[3] Non-Consumers Energy thermal generating units include thermal generating units outside of the Consumers Energy footprint but within the MISO model topology presented in Exhibit A-8 (STW-5).

Additional support of the underlying DSM input assumptions included in the AT scenario can be found in the direct testimony of Company witness Steven Q. McLean.

Q. Are the natural gas prices used in the eight scenarios based on reasonably current commodity price outlooks?

A. The gas prices used in the AEO gas scenarios and the AT scenario were from the EIA's 2020 AEO, published in February 2020. An updated 2021 AEO was published in February 2021; however, the Company was not able to utilize the February updates in this filing. Development of inputs used in modeling was initiated in January 2020 and required significant time to complete all required scenarios and sensitivities. Furthermore, decisions regarding the fossil-fueled generating unit retirements were based on modeling mostly completed prior to the 2021 AEO release. The 2021 AEO reflects slightly lower projected natural gas prices than the 2020 AEO starting in year 2025 and continuing through the planning period. Specifically, on average, starting in 2025, annual prices decreased by approximately 4%.

Gas prices used in the Consumers Energy gas scenarios are also based on projections from February 2020. More recent prices from February 2021 vary minimally from February 2020 projections (chosen to be consistent with timing of the 2021 AEO data release) for most years. In the first three years of the study period, 2021 through 2023, recent gas prices are higher than the February 2020 outlook (an average of 13% higher). In years 2024 and 2025, more recent projections are 3% higher than last years. Beginning in 2027, and continuing through most of the study period, the February 2021 outlook projects lower prices (an average difference of 5%) compared to the prices used in modeling.

Q. What are the likely impacts from the differences in gas prices identified?

A. Recent updates to the AEO gas price forecast and the Consumers Energy gas price forecast reflect decreases in forecasted natural gas prices compared to those used in IRP modeling. However, the Consumers Energy gas price difference of approximately 5% for most of the study period and the AEO gas price difference of approximately 4% are minimal and not expected to change the results of this IRP in any significant way. Specifically, such small differences are unlikely to change the resource plans in the Aurora optimizations, or Net Present Values ("NPV") differences between sensitivities that are presented.

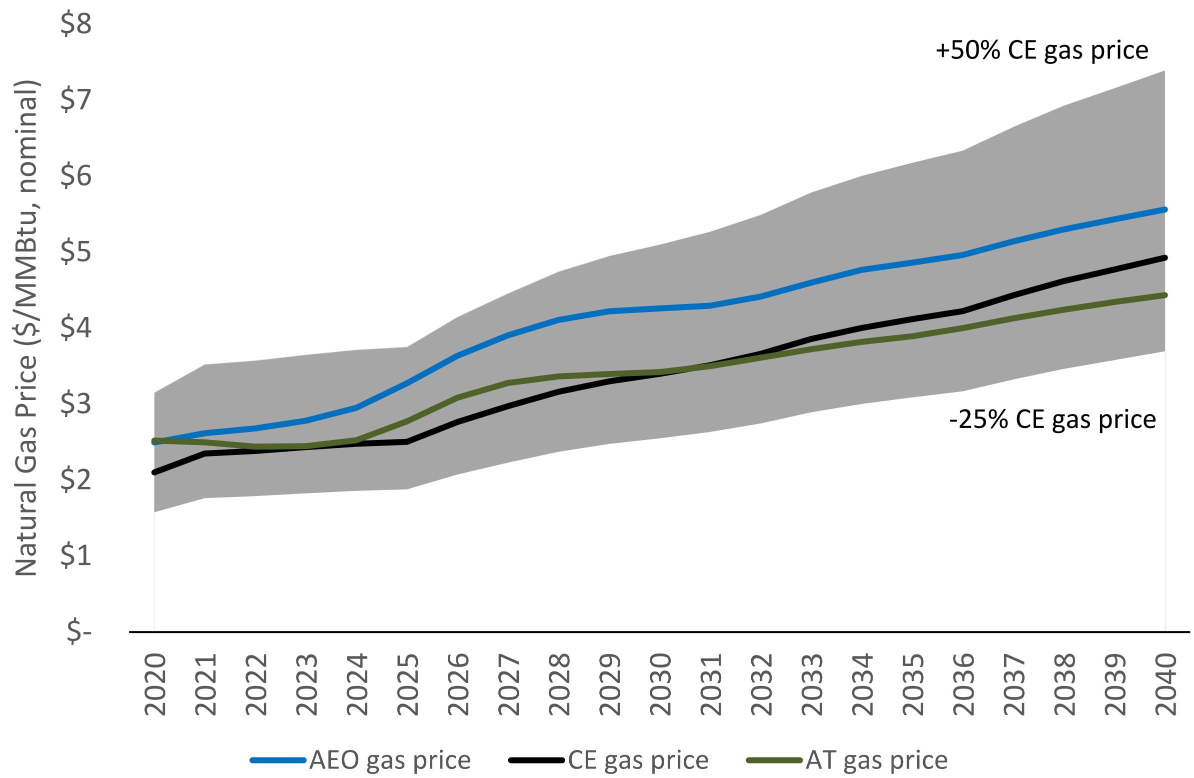
Q. How do the three natural gas price forecasts compare to one another?

A. The Consumers Energy gas price forecast is materially below the AEO gas price forecast. The AT gas price is materially below the AEO forecast; but varies over time in the relation to the Consumers Energy gas price forecast. Through the 2020s, the Consumers Energy gas price forecast is the lowest – lower than the AT gas price forecast. However, for years 2030 through 2040, the AT gas price forecast (which assumed depressed natural gas prices due to high supply of the commodity) drop below the Consumers Energy forecast.

Q. How does Consumers Energy address the differences in these natural gas price forecasts?

A. For purposes of retirement analysis included in this IRP, the Company performs a natural gas price sensitivity analysis that considers a sufficiently broad range of prices so as to include all price forecasts mentioned in this section. Additional discussion is included in the testimony of Company witness Anna K. Munie. Figure 1, below, includes the three gas price forecasts utilized in this IRP as line series, as well as a shaded region, which indicates the range of prices included in the Consumers Energy retirement analyses natural gas price sensitivities.

Figure 1: Natural Gas Prices Included in 2021 IRP Analyses



SECTION V: PROCESS USED IN MODELING

Q. Please provide a general description of the process used in modeling for the Company's IRP.

A. The process used for IRP modeling is based on the requirements contained in MCL 460.6t and in the MIRPP. Consumers Energy utilized its existing robust resource planning process, comprised of multiple inputs, calculations, and models, to meet these requirements. The planning process begins by developing base forecasts of key planning parameters. These key planning parameters include consideration of: (i) electric demand forecasts; (ii) existing supply-side resources; (iii) existing demand-side resources such as

EWR, CVR, and DR; (iv) renewable portfolio requirements; (v) applicable commodity pricing for carbon, natural gas, coal, and oil; (vi) environmental compliance requirements; and (vii) system constraints such as reserve margin, energy import capability, and capacity import capability.

The IRP modeling process includes multiple interrelated steps to develop and evaluate potential resource portfolios. These steps are iterative in nature because information is passed back and forth among the steps, and implications of some of the analytical steps could result in returning to previous steps for further analysis. A summary of each of the major steps is provided below:

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

Capacity Position

Q. Step 1 of the process used in modeling is identified as determining capacity needs and the first year of need. Please explain how that determination is made.

A. Determination of capacity need is established by comparing projected peak demand levels and required reserve margins against existing and planned capacity resources.

Q. What are the Company's existing and planned capacity resources?

A. Section VI of this testimony identifies existing (or planned) resources included in the Company's base case, with details provided in Exhibit A-6 (STW-3).

Q. How does the Commission final Order in the Company's 2018 IRP (Case No. U-20165) impact existing and planned capacity resources?

A. The approved Settlement Agreement from MPSC Case No. U-20165 (the Company's 2018 IRP) provided approval for the recovery of costs for only the first three years of the study period. Specifically, the approval included the Company's plans to expand DR to 607 MW through year 2022; expansion of EWR at 2% of prior year sales through year 2023; and the acquisition of 1,100 MW of solar capacity through year 2024.

Q. In this IRP, how is the Company treating all remaining capacity resources included in the long-term plan presented in the 2018 IRP?

A. All remaining resources included in the long-term plan presented in the 2018 IRP will be removed from the portfolio as part of this IRP and re-evaluated for economic consideration. The remaining portfolio of resources, along with the corresponding date assumed as each resource's current end of life is compared to the Company's base case forecasted PRMR[4], which identifies years in which a shortfall of capacity occurs.

Q. What is the goal of an IRP as it relates to PRMR?

A. The goal of an IRP is to develop a plan to meet PRMR in each planning year of the study horizon.

[4] The planning reserve margin requirement (PRMR) is calculated based on the Company's annual forecast of bundled customer demand at the time of the MISO peak demand, plus approximately 8.9% reserves.

Q. When does the Company anticipate a capacity need under the assumptions identified above?

A. Figure 2, below, presents the result of the aforementioned comparison for the Consumers Energy scenario base case and indicates that under current assumed retirement schedules, the Company has no capacity need until 2029.

<u>Figure 2: Consumers Energy Scenario Base Case Balance of Supply and Demand to Meet PRMR</u>

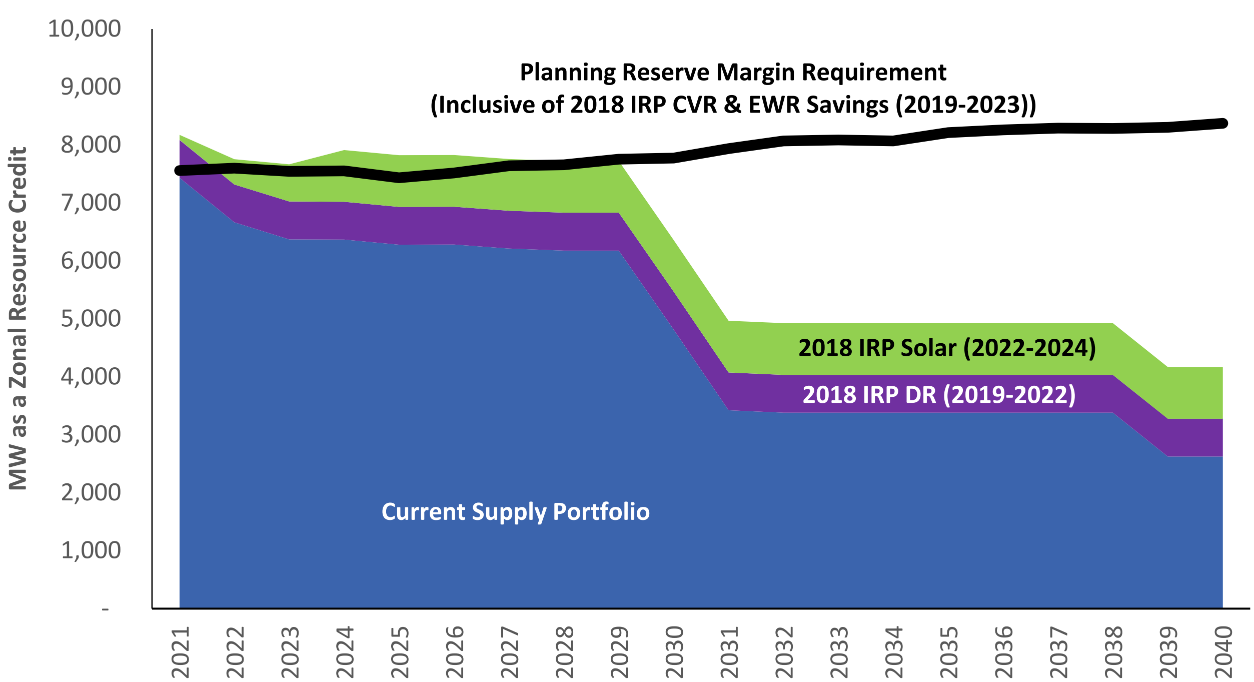
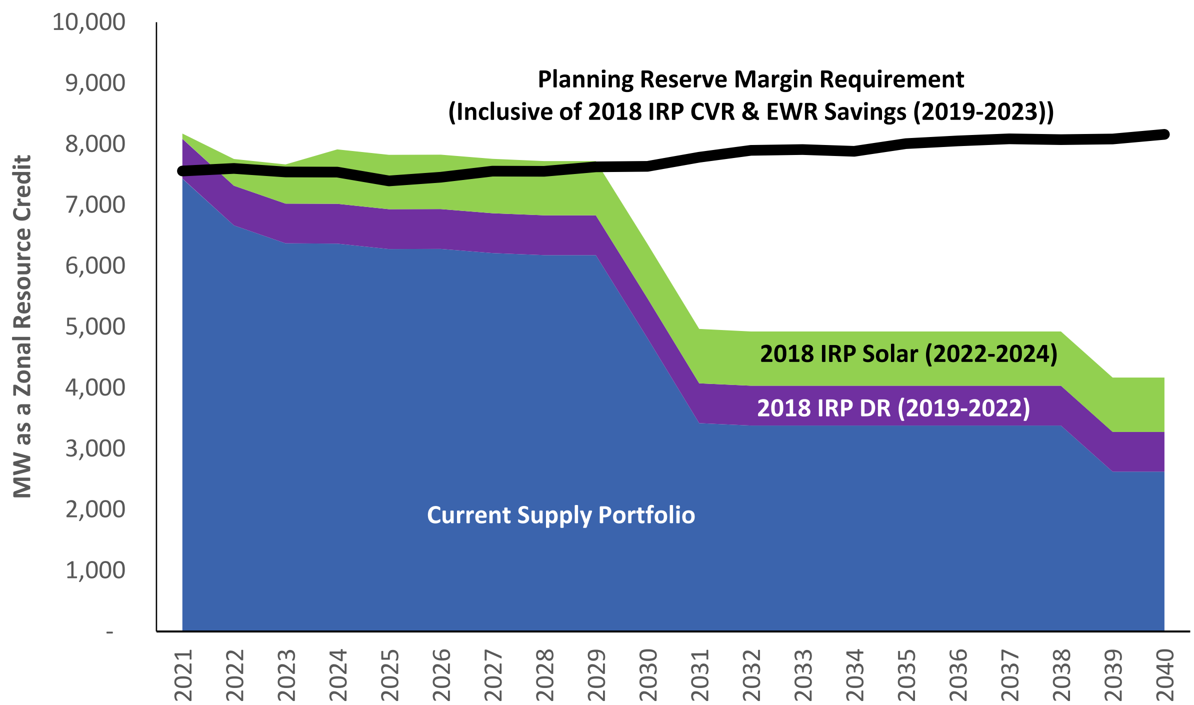


Figure 3 is the same comparison, but for the MPSC scenario base case:

Figure 3: MPSC Scenario Base Case Balance of Supply and Demand to Meet PRMR



Viable Resource Options

Q. Step 2 of the modeling process requires identification of viable resource options considered by the Company to meet future peak demand requirements. Please explain.

A. Identification of viable resource options requires a review of existing resources as well as potential resource options. Existing resources include the generating units owned by the Company, energy and capacity supplied through Power Purchase Agreements ("PPAs"), existing transmission capabilities, short-term or spot market purchases, and demand-side resources currently available to the Company. Potential resource options include additional new generating unit technologies, transmission expansion projects and upgrades, additional short-term or spot market purchases, and expanded EWR and demand-side resources. More information is provided in Section VI of this direct testimony.

Development of Production Cost Models

Q. How were the production cost models and inputs for various assumptions developed in Step 3 of the modeling process?

A. The input data required to develop the models is extensive due to the volume and complexity necessary to perform long-term capacity expansion ("LTCE") and production cost modeling. Many major input assumptions to the base models used were explicitly defined in the MIRPP.

Q. What were the sources of the major assumptions and forecasts modeled in this IRP?

A. The Company relied upon internal and external subject matter experts to develop many of the major assumptions and forecasts modeled in the IRP. Subject matter experts are included as witnesses in this proceeding. Below is a discussion of each of the major input assumptions and the source for those input assumptions:

- The first major assumption collected was a series of load forecasts. Six load forecast outlooks were developed for this IRP. Three base load forecasts were developed for the first eight scenarios.
    - Under the Consumers Energy gas scenarios and sensitivities, a base load forecast that assumed EWR levels at 2% through 2023 and 1% cumulative in years 2024-2040 was developed.
    - For the AEO natural gas base case scenarios and most sensitivities, a base load forecast that assumed EWR levels at 2% through 2023 and 1.5% cumulative in years 2024-2040 was developed. The exceptions to that generality are three load forecasts developed for the following sensitivities: 1.5% load growth, 2.5% EWR, and 50% Retail Open Access ("ROA") return.
    - The final load forecast developed was for evaluation in the AT scenario. This base load forecast assumed EWR remained at 2% throughout the study period, included increased consumption for electric vehicle charging, and also included reduction in forecasted demand to represent behind-the-meter generation. Behind-the-meter generation is supply sources at customer locations. Since these are such small sources of electric supply, and since they are behind the meter and not accounted

for on the utility distribution or transmission systems, the energy is modeled as a *reduction in load* instead of a supply resource.

For further information regarding load forecast development, please see the direct testimony of Company witness Eugène M. Breuring.

- An accounting of all existing supply and demand-side resources was undertaken. An overview of the Company's existing portfolio can be found in Exhibit A-6 (STW-3), as well as Section 7 of the IRP Report, Exhibit A-2 (RTB-2). For additional information on existing units and their projected retirement dates, please see the direct testimony of Company witness Norman J. Kapala.

- The next major assumption included existing renewable energy inputs, including output, capacity factor, and tax credits. This information was used as an input in all base case scenarios and sensitivities. For further information regarding renewable energy assumptions and inputs, please see the direct testimony of Company witness Teresa E. Hatcher. For further information regarding Production Tax Credit ("PTC") and Investment Tax Credit ("ITC") laws related to renewable energy technologies, please see the direct testimony of Company witness Carolee Kvoriak.

- The next major assumption included existing and capacity expansion options for EWR programs, including incremental decreases in retail sales and forecasted peak demand and impact. This information was used as an input in all base case scenarios and sensitivities. For further information regarding EWR programs and assumptions, please see the direct testimony of Company witness McLean, and Section VII of this direct testimony.

- The next major assumption was regarding demand-side management programs, including direct load control, dynamic peak pricing, CVR, and incremental DR. This information was used as an input in all base case scenarios, with varying levels of growth and expansion between BAU, ET, and EP. For more information regarding demand-side management programs, please see the direct testimony of Company witnesses Matthew S. Henry for CVR, and Emily A. McGraw for DR, as well as Section VII of this direct testimony.

- The next major assumption was regarding operating parameters and capital and operating costs for new supply-side resources (Combined Cycle ("CC"), Combustion Turbine ("CT"), wind, solar, and battery storage). The capital costs for certain resources were specified for each given scenario (for example, solar capital costs in the ET and EP scenarios are required to be 35% below BAU). For more information on the new supply-side technology resources, please see the direct testimony of Company witness Jeffrey E. Battaglia.

- The next major assumption was regarding network upgrade costs for all new generation resources. The information was used in all base case scenarios and sensitivities. For more information on network upgrade costs, please see the direct testimony of Company witness Benjamin T. Scott.

- The next major assumption was the amount of capacity import and export capabilities into and out of Zone 7. Please see the direct testimony of Company witness Scott for additional information.

- The next major assumption was the levels of effective load carrying capability ("ELCC") for *new* technology resources, which determines how much of a resource's installed capacity can be counted to meet the PRMR. This information is published by the Midcontinent Independent System Operator ("MISO") on an annual basis in its Wind & Solar Capacity Credit report[5] or calculated, using MISO-published class average equivalent forced outage rates.

- The next major assumption was in regard to forecasted fuel prices throughout the planning period. Fuel price forecasts include pricing for coal, natural gas, and oil. This information was used in the base case for all identified scenarios and sensitivities, with the exception of the 200% gas sensitivity, in which the projected cost of natural gas (based on EIA AEO natural gas price) was assumed to double by the end of the planning period. For more information regarding fuel prices and forecasts, please see the direct testimony of Company witness Gallaway.

- Existing PPAs with Non-Utility Generators were assumed to expire at existing contract expiration dates. However, as discussed in the direct testimony of Company witness Keith G. Troyer, some PPAs were assumed to continue to be renewed and are included as an aggregated generating resource in the base case scenarios and sensitivities. The contract with Entergy Nuclear Power Marketing, LLC for capacity and energy provided by the Palisades Power Plant ("Palisades") was assumed to expire in May 2022. The contract with Midland Cogeneration Venture Limited Partnership ("MCV") is assumed to expire in May 2030, as approved by the MPSC Commission in U-20896. For more information on these and other wholesale energy and/or capacity contracts, please see the direct testimony of Company witness Troyer.

- The final major assumption made was regarding economic parameters such as an assumed discount rate and Fixed Charge Rate ("FCR"). All base scenarios, and all MPSC-required sensitivities, were modeled using an assumed rate of return as approved in Case No. U-20134. A modeling sensitivity was run utilizing a 2.5% discount rate to consider impacts to NPV results at what can be considered a "social discount rate," closer to the rate of economic inflation. This sensitivity is presented in this IRP in response to several internal and external discussions regarding the appropriate rate by which to discount future customer costs. This modeling sensitivity will inform directional impacts that lower discount rate might have on resulting modeling assumptions, inputs, resource

[5] https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

plans, and associated NPVs within the different scenarios. Please see Section X of this direct testimony regarding modeling results and conclusions for further discussion.

Q. How were fossil-fueled generating unit retirements addressed in the base case scenarios?

A. With regard to the fossil-fueled generating unit retirement analysis previously referenced, the Company embedded the outcome of that analysis as an input to its base cases for the AEO gas price outlook scenarios. Specifically, the Company's base capacity outlook assumes retirement of Karn Units 3 and 4 in 2023, and assumes retirement of Campbell Units 1, 2, and 3 in 2025. Accordingly, for clarity, any discussion related to base case will hereafter assume that "base case" refers to Consumers Energy gas cases in which Karn Units 3 and 4, and Campbell Units 1, and 2, are assumed to operate through 2031 and Campbell Unit 3 is assumed to operate until 2039, while "retirement base case" will refer to cases in which Karn Units 3 and 4 are assumed to retire in 2023 and Campbell Units 1, 2, and 3 in 2025. The details of the retirement analysis are described in detail in the direct testimony of Company witness Blumenstock.

Q. Were the decisions regarding the use of inputs, developed by subject matter experts in this case, in the modeling made by you or under your supervision?

A. The development of production cost models for use in an IRP requires careful development of input assumptions from many subject matter experts. All inputs and modeling decisions were carefully reviewed by me or under my supervision.

Construction of Optimization Portfolios

Q. Describe how portfolios were constructed for evaluation, Step 4, of the modeling process.

A. Section VIII of this direct testimony details development of optimization portfolios. Generally speaking, a portfolio is a collection of resources (supply-side or demand-side) that can be used to fill a capacity need. Several different combinations of resources can be offered into the optimization and are selected by Aurora based on the lowest-cost outcome, from all possible options considered. The outcome of Aurora – the selected mix, amounts, and timing of resources – is then evaluated for relative cost, feasibility, resource diversity, environmental impacts, and more.

Capacity Expansion and Production Cost Simulations/Evaluation of Portfolio Using Qualitative and Quantitative Measures

Q. Step 5 requires performing capacity expansion and production cost simulation analysis and Step 6 requires evaluation of portfolios using quantitative and qualitative measures. How are these steps of the modeling process performed?

A. The Company conducted this analysis using Aurora, a computer software application.

Q. Please describe the Aurora software, and in what capacity that software was utilized.

A. The Company uses proprietary data and software programs in its integrated resource planning activities. The Company uses Aurora to develop its resource plan and alternatives. Aurora, a computer software application developed by Energy Exemplar ("EE"), supports electric utility decision analysis and corporate strategic planning. The Company also uses EE's database, which is used primarily for regional market modeling of energy resources and demand.

Q. Please identify the entity responsible for development of the models used in the IRP process.

A. The models were developed solely by the Company. Models of Consumers Energy's system were derived from input data provided by internal sources. Models of the regional market area outside of Consumers Energy's service area were derived from a mixture of sources including EE's database software, publicly filed documents, and internal planning assumptions.

Q. Please provide a general description of the Aurora modeling process.

A. The Aurora model simulates the commitment and dispatch of the Company's generation resources and the resources of all generators in the MISO footprint on the basis of a typical week representing each month over the planning period. The planning period for the IRP covers the 21-year period beginning January 1, 2020 and ending December 31, 2040.

In capacity expansion mode, the software selects incremental capacity additions from a selection of various resource options according to technology, amount, and timing to arrive at a least-cost resource plan that is a co-optimization of meeting hourly energy requirements as well as ensuring that required capacity reserve margins are maintained. Aurora will consider several alternative combinations of resources offered within user-defined modeling constraints and then rank the multiple combinations in economic order. To do so, the software calculates the costs associated with variable Operating and Maintenance ("O&M") expense, fuel expense, and emission expense for each hour of operation using the least expensive units to generate in each hour, abiding by operational constraints. For units added to maintain required capacity reserve margins, the model also calculates the economic carrying costs[6] and operating costs for each unit added, but does not include the carrying costs or fixed operating costs of units already included in rate base. The IRP modeling also excludes some fixed costs for existing resources that are common to all scenarios and sensitivities and have no impact on generating unit dispatch and resource plan optimization results.

With the nominal values developed for each month of the planning period, the NPV of the revenue requirement[7] is calculated and the alternative resource plans considered within the model are ranked in economic order from lowest to highest NPV. Post-optimization, any surplus capacity that remains after PRMR are met is assumed to be sold at the market price of capacity[8]. The surplus capacity revenue is not calculated within the model so as not to influence the model into building or adding new resources simply to sell off into the market. The result of this overall modeling process is the identification of the most cost-effective resource portfolio for each scenario and sensitivity.

Q. Is this how the eight scenarios identified earlier in this testimony were modeled?

A. Yes. As mentioned earlier, eight scenarios were evaluated in this IRP along with multiple sensitivities on key parameters in all scenarios. For each scenario and sensitivity, multiple Aurora-selected resource combinations for the Company were constructed and evaluated based on criteria such as cost, resource diversity, feasibility, and environmental impact.

[6] The Economic Carrying Charge ("ECC") is a method for quantifying capital cost streams in financial analysis and resource planning. The ECC is used in resource optimization models such as Aurora because it appropriately allocates the portion of capital costs to a project for a given time period, in the case that the project lifetime does not exactly align with the planning period of the model run. The ECC method also makes feasible a comparison of resources with different lifespans and commercial operation dates.
[7] NPV of the revenue requirements represents the current value (2020 dollars) of a stream of annual revenue requirements the Company must receive from its customers in order to cover all costs, operating expenses, taxes, depreciation, and return on investment.
[8] The market price of capacity in this IRP is assumed to be 75% of the Cost of New Entry ("CONE") of a CT unit. The value of CONE was published by MISO, as submitted to the Federal Energy Regulatory Commission in September 2019 for planning year 2020-2021.

Additionally, since the entire MISO market area is represented in the Aurora IRP model, for each scenario and many sensitivities, capacity expansion simulations were performed for the entire regional market area. Based on the optimized regional market area, the model then was able to optimize the Consumers Energy system. This methodology provides a balanced view of long-term reliability requirements in the study for the Consumers Energy system, the Lower Peninsula of Michigan, as well as the entire MISO market footprint. The result of this multi-step modeling process is a comprehensive plan that considers the interchange of power between the Consumers Energy system and the rest of the MISO market.

Q. Please describe the factors affecting model accuracy.

A. Several key factors influence the accuracy of the modeling results. It should be noted that, in this context, model "accuracy" refers to the degree to which the model can be expected to accurately reflect future conditions. The key factors influencing model accuracy include the validity of input assumptions, complexity of generating unit operations, and the complexity of the interconnection between systems. The Company took great care to develop accurate and valid input assumptions for the required scenarios and sensitivities; however, as with any forecast, a high degree of uncertainty over a 20-year planning period exists. As discussed at length in the direct testimony of Company witness Blumenstock, the Company's PCA mitigates, to great degree, the execution risks inherent in a typical large-scale utility resource plan. Specifically, the Company's PCA provides for a modular and adaptable resource plan that can evolve and shift with the inevitable changes to various input assumptions such as cost of new technologies, performance of new technologies, remaining life of existing assets, significant changes in customer demand, and environmental regulations.

Q. Please describe the sensitivity of forecasts to variability in assumptions.

A. Because the forecasted assumptions used in the modeling of the Consumers Energy system are variable and statistical in nature, it is critical to ensure that the assumptions used in the various scenarios and sensitivities cover the range of reasonably possible values. Inherent variability and risk associated with input assumptions were addressed in the initial phases of the IRP process through the stakeholder engagement process and thoughtful development of the scenarios and sensitivities to include specific parameters known to be key uncertainties. Additional details regarding this process are provided in the direct testimony of Company witness Blumenstock.

Q. Did the Company seek third party industry expert assistance for this IRP, and in what capacity was this assistance utilized?

A. Yes. The Company contracted a third-party review of its modeling through Siemens PTI Consulting. The Aurora models used in support of the IRP were provided to Siemens in order for them to review input assumptions, modeling methodologies and model selections. The detailed report of Siemens review is included in Company witness Blumenstock's Exhibit A-3 (RTB-3).

Portfolio Analysis

Q. Step 7 of the modeling process requires evaluation of portfolios through scenario and sensitivity analysis. Please explain that process.

A. Section X of this direct testimony, Summary of Modeling Results, provides evaluations, comparisons, and key conclusions and observations of the scenarios and sensitivities evaluated in this IRP.

Risk Analysis

Q. Please discuss Step 8, completion of a risk analysis.

A. The Company completed multiple levels of risk assessment within this IRP, including Stochastic risk analysis, portfolio risk assessment, scenario and sensitivity modeling and electric reliability analysis. Section XI of this direct testimony discusses the electric reliability risk analysis, while the testimony of Company witness Munie discusses the remaining risk assessments.

Determination of the Proposed Course of Action

Q. Please discuss Step 9, the determination of the most reasonable and prudent plan, the best IRP for Michigan.

A. Final development and selection of the PCA is discussed in Section X of this direct testimony, as well as in the testimony of Company witness Blumenstock.

As described above, the Company's nine-step approach to fulfilling the requirements of an IRP is a multi-step process that has been designed to evaluate a broad range of potential resource portfolios across identified scenarios and sensitivities to determine the amounts and types of resources that best meet the long term needs of Michigan from a variety of perspectives.

SECTION VI: RESOURCE OPTIONS CONSIDERED IN THE IRP

Q. What assumptions regarding existing and planned supply-side resources are included in the IRP?

A. The Company's diverse portfolio of existing generating resources includes a mix of owned resources and PPAs. Company witnesses Blumenstock, Kapala, Troyer, McLean, Hatcher, Henry, and McGraw describe the IRP assumptions related to these existing supply and demand-side resources, as well as currently planned additions, such as future projects included in the Company's Renewable Energy Plan and projected expansion of EWR and DR programs. The assumptions regarding these existing and planned supply and demand-side resources are common to all scenarios and sensitivities within the IRP. In addition to resources included in Exhibit A-6 (STW-3), the base case scenarios include the following major planned capacity resources:

- EWR savings at 2% through 2023 and dropping to 1.0% cumulative for years 2024-2040;
- Addition of the Heartland, Crescent and Gratiot wind farms;
- Addition of the River Fork PPA, 100 MW by 2021;
- Addition of 584 MW of PURPA QF solar capacity by 2023;
- Addition of 1,100 MW of 2018 IRP approved solar capacity by 2025;
- Increasing levels of DR, reaching 607 MW by 2022;
- The expiration of the Palisades PPA in May of 2022;
- The expiration of the MCV PPA in May of 2030;
- The retirement of Karn Units 1 and 2 in 2023;
- The retirement of Karn Units 3 and 4 in 2031;
- The retirement of Campbell Units 1 and 2 in May 2031;
- The retirement of Campbell Unit 3 in May 2039; and
- The operation of the Zeeland, Jackson, Ludington, hydro and other renewable facility resources through the duration of the study period.

Q. Please explain Exhibit A-6 (STW-3).

A. Exhibit A-6 (STW-3) provides information regarding the Company's 2021 IRP Existing Assets Zonal Resource Credits[9] and Projected Generation. The first four pages of Exhibit

[9] A zonal resource credit is equivalent to 1 MW of resource capacity, discounted for the resource's effective forced outage rate.

A-6 (STW-3) provide the zonal resource credits each generating unit in the Company's portfolio contributes, by year. Page 1 includes owned generating units; at the bottom of page 1, the listing of non-utility generators ("NUG") begins and continues onto pages 2 through 4. Some of the contract names may be repeated; for example, Adrian Energy Associates appears on line 55 of page 1 and again on line 117 of page 2. This is because the Company assumes that certain PURPA qualifying facility ("QF") contracts that have an expiration date specified may decide to sign a new contract under the same facility; therefore, as the contract expires, as indicated in the section titled "Non-Utility Generators (NUGS)," some contracts pick up where the current contract expires and is presented under the section called "New Contracts w/ Existing PURPA QFs".

Beginning on page 5, the projected generation in MWh is presented for each resource, as projected under the BAU base case. While most lines in Exhibit A-6 (STW-3) represent a single plant or resource, page 6, lines 75 and 76 represent an aggregate of the resources that are assumed to be available under the new contracts with existing QFs.

Q. What resources, other than the existing and planned resources previously described, were considered as potential supply options to serve demand in the future?

A. As part of its planning process, the Company considered a wide range of supply-side resources to serve future electric demand. Due to the volume of calculations made by the Aurora model as it solves for all potential solutions to satisfy the model's constraints, not all possible resources are made available for selection in every scenario. Some resource technologies, therefore, were "screened out" before the scenarios and sensitivities were modeled. The technologies were screened on criteria such as commercial availability, cost, scale, resource type (e.g., peaking, intermediate, and baseload), technical viability, and other considerations. New-construction technology resources that were screened out include the following:

- Thermal Storage - An initial technical screening indicated thermal storage was a higher cost application than other options associated with energy storage;
- Compressed Air - An initial technical screening indicated compressed air technology did not demonstrate enough technological advancement to be applied at a utility scale level;
- Flywheel - An initial technical screening indicated flywheel technologies were a higher cost application than other options associated with energy storage;
- Combined Heat and Power - Based upon Company subject matter expert feedback, the current and future economics and growth of Combined Heat and Power does not reflect a feasible alternative to consider as an alternate resource. The need for a steady steam supply tied to site-specific requirements makes this type of facility less viable then other resources;
- Fuel Cells - Initial technical screening indicated fuel cells were a higher cost application than other options associated with energy storage; and
- Geothermal - An initial technical screening indicated geothermal storage did not demonstrate enough technological advancement to be applied at a utility scale level.

Q. Please discuss how resources not screened out were then considered?

A. A preliminary economic analysis of the remaining new-construction technologies not screened out was performed using a Levelized Cost of Energy ("LCOE") comparison between similar technologies. Exhibit A-7 (STW-4) presents a comparison, based on the LCOE, of the various resources considered for final selection to be offered into the capacity expansion runs.

Q. What does an LCOE comparison do to assist in determining potential supply options to meet demand in the future?

A. An LCOE comparison allows a comparison of resources based on the amount of energy delivered by that resource, relative to the costs of construction, O&M, fuel, applicable network upgrade costs, as well as any offsetting revenues provided via tax credits or other means. The levelizing function allows the Company to take a varying stream of numbers and reduce them to one value, representing the entire period. Usually costs increase over time; levelization takes these increasing values, discounts them, and expresses the result as one number, usually in the current year dollars. However, it is very important to note that while LCOE can be a useful tool for comparison across multiple technologies, it has pitfalls as well. Specifically, for resources that are designed primarily to provide capacity, with potentially very little energy production, the LCOE of that resource can look poor, relative to other resources. Exhibit A-7 (STW-4) compares most resources according to the magnitude of their LCOE; however, a second page was necessary for DR, since those resources produce very little energy and have resulting high LCOE values.

Q. How did the Company respond to its supply option review?

A. As a result of the supply option review, the Company has focused its modeling on the following specific supply-side technologies: natural gas-fueled CTs, natural gas-fueled CC units, natural-gas fueled Reciprocating Internal Combustion Engine units, wind, solar, and battery storage. Resources such as coal, nuclear, and H-class CTs were not included in the portfolio optimizations. Coal and nuclear are not attractive resource options because of intensive capital costs and long time periods required for construction, and coal does not align with the Company's clean and lean objective. H-class CTs had high LCOE and did not provide the higher levels of Zonal Resource Credits ("ZRCs") as F-class CTs.

For details regarding the operating parameters and costs for natural-gas fueled, renewable energy, and storage technologies, please see the direct testimony and exhibits of Company witness Battaglia and Company witness Nathan J. Washburn.

Finally, for purposes of the development of the reference portfolio, described later in this direct testimony, the Company considers the hypothetical capacity replacement in which other MISO market participants may have capacity available for sale from existing and new generating facilities. For purposes of comparison, the Company evaluated a portfolio in which capacity can be purchased on a short-term or spot basis at a forecasted market capacity price.

Q. What assumptions regarding existing and currently planned demand-side resources are included in the IRP?

A. Existing and planned demand-side management programs generally fall into two categories:

1. Peak, or demand, load management programs that are designed to reduce demand during system peak hours, thereby avoiding or deferring new capital investment for generation and transmission; and
2. EWR that is designed to reduce long-term energy use through increased efficiency of energy consuming equipment, conservation programs that promote the use of more energy efficient building materials, and educational programs that promote the merits of lower overall use of energy and attempt to motivate a change in customer behavior.

Demand-side controls and EWR programs have and will continue to be effective resource options for the Company. Accordingly, the IRP includes forecasts of expanded EWR and demand reduction programs, as discussed in the direct testimonies of Company witnesses McLean and McGraw.

Q. Were additional energy efficiency and demand-side resources, other than what was previously described, modeled in the IRP as potential resource alternatives to meet future demand?

A. Yes. Additional demand-side management measures were evaluated in the IRP modeling through several scenarios and sensitivities, as presented in Section IV of this direct testimony, and were also offered for economic selection in the Aurora optimization simulations. The program and cost assumptions related to these demand-side management options are summarized in the direct testimony of Company witnesses McLean, Henry, and McGraw, as well as Section VII of this direct testimony.

Q. What assumptions regarding existing transmission resources are included in the IRP?

A. Two fundamental assumptions in the Company's resource need assessment and planning process are the transmission topology and the representation of the constraints and limitations on the existing transmission system. The transmission topology can best be represented by a series of zones representing "transmission areas" or "zones," which are interconnected by transmission "paths." Within each of the zones are the hourly customer loads and electric generating resources. The paths reflect the aggregate import and export limitations of all transmission lines between the zones. Exhibit A-8 (STW-5) provides the Company's representation of the basic transmission topology for the MISO market footprint within the Aurora IRP model. Further discussion of the import and export capabilities is also provided in the direct testimony of Company witness Scott.

Q. Were transmission options, other than what was previously described, considered as a supply resource in the IRP?

A. Yes. The IRP considers the potential role of transmission expansion in helping to meet future demand requirements. Company witness Scott discusses the various transmission expansion options that were evaluated although not explicitly modeled in the IRP.

Q. Were there any limitations imposed on the resource selections completed in Aurora?

A. Yes. Certain constraints are imposed on the model runs in Aurora for a number of reasons. Some of those reasons include:

- Feasibility of resources that can be selected;
- Timing of resource availability; and
- The amount of excess capacity build permitted.

Q. Explain how constraints are imposed in Aurora due to feasibility of resources that can be selected.

A. The first constraint – imposed on wind expansion -- was applied to capacity expansion in the regional market model (the larger MISO footprint). Particularly during periods in which wind generation resources earned PTC, wind expansion in the regional market was widely selected through year 2024, in excess of 13 gigawatts (GW) of added wind capacity in a single year. The Company conducted research to estimate reasonable amounts of wind capacity that would be added in the region, specifically, the Company reviewed recently-approved projects and projects currently awaiting approval in the MISO transmission queue. Through that research, the Company observed that not more than approximately 5.5 GW of wind is approved per year. Accordingly, optimizations for the MISO footprint were constrained to expansion at 5.5 GW per year.

Q. Explain how the Aurora optimizations are constrained due to timing of resource availability.

A. Some resources require significant construction lead time prior to the commercial operation date (for supply-side resources) or significant lead time to ramp up (for demand-side management programs); therefore, constraints were imposed on the optimization to indicate a "first-year available" for each individual resource option.

- Natural gas: Economic selection of a CT unit can be made as early as year 2023, but a CC unit would not be available for economic selection until 2025, due to the increased lead time for a CC unit;

- Solar: The solar expansion plan approved for the first three years of the 2018 IRP PCA committed the Company to annual competitive solicitations in years 2022, 2023, and 2024; therefore, the first year of section of solar was set as 2025;

- Wind: Economic selection of wind resources can be made as early as year 2023, assuming that the Company could potentially enter into a PPA or a build-transfer agreement by that time;

- Storage: Economic selection of battery storage resources can be made as early as year 2025, assuming that the Company could potentially enter into a PPA or a build-transfer agreement by that time;

- EWR: The Company's EWR Plan filing approved EWR levels of 2% through year 2023; therefore, any expansion of EWR can be added starting in year 2024; and

- Demand Response: Like solar capacity, the 2018 IRP PCA provided for pre-approved levels of demand response. In the 2018 IRP, the Company committed to achieving 607 MW of demand response by 2022; therefore, expansion of DR can be selected starting in year 2023.

Q. Explain how the Aurora optimizations are constrained for the amount of excess capacity built.

A. In order to conduct an optimization for a resource plan, the Company inputs a minimum amount of capacity addition required, as well as a maximum amount allowed. The minimum amount corresponds to the known capacity shortfall, while the maximum is user-defined. If no maximum amount of excess capacity is defined, Aurora may add new resources that are not required to meet customer peak demand. In order to understand the resource mix most optimally selected by Aurora, the Company limited the amount of excess capacity additions by imposing a requirement that no more than 400 MW of surplus capacity is permitted.[10] The value of 400 MW was determined according to the size of available resources in this IRP. A surplus level of up to 400 MW allows unbiased economic

[10] In very few portfolio optimizations, the 400 MW limitation was modified, in order to understand how the resource mix could change, due to differences related to the size of particular expansion resource options.

selection of any resources that are sized 400 MW or less, which includes all resources apart from CC gas units and some of the larger DR blocks. By limiting the amount of excess capacity, the Company is able to identify which resources are selected first to meet precisely specified customer demand levels, within the Aurora optimizations.

SECTION VII: DEVELOPMENT OF DEMAND-SIDE OPTIONS FOR AURORA

Q. What demand-side resources were considered in the Aurora modeling?

A. In addition to the supply-side resources previously mentioned, three demand-side options were included in the Aurora portfolio optimization runs:

1. CVR: This program is explained fully in the direct testimony of Company witness Henry;
2. Increasing levels of DR: An aggregate of multiple different types of DR programs such as smart thermostat programs, capacity bidding, and direct load control were offered in this IRP. More information can be found in the direct testimony of Company witnesses McGraw; and
3. EWR: The Company's base case assumes 2.0% EWR savings growth 2021-2023 and 1.0% cumulative for years 2024-2040. Expansion of EWR savings were offered into the optimization beyond the base case assumption. Further information can be found in the direct testimony of Company witnesses McLean and Lakin Garth.

Conservation Voltage Reduction

Q. Please describe the CVR Program offered into Aurora.

A. As explained in the direct testimony of Company witness Henry, CVR is a program that offers both an energy and peak demand benefit. To model this program in Aurora, projected MWh (energy) and MW (peak demand) reductions were provided to Company witness Breuring to incorporate into the load forecast. The levels of CVR included in the load forecast are summarized by Company witness Henry and presented in Exhibit A-86 (MSH-1).

As presented in the direct testimony of Company witness Henry, the CVR Program requires advanced ramping in order to achieve material peak demand reductions, starting with investments as well as MWh and MW reduction benefits in 2019. In 2021, the program is expected to provide approximately 20 MW of peak load reduction. For each subsequent year, an additional 10 to 11 MW of peak load reduction is expected, until year 2030, when the program's peak MW reduction occurs at 113 MW. The costs of the program are discussed in the direct testimony of Company witness Henry.

The first year in which resource selection begins under any scenario or sensitivity is 2023; but in Aurora optimizations, the CVR Program is assumed to begin in 2020 regardless, in order to achieve the maximum levels of peak demand reductions by the time resource optimization begins. The CVR Program, therefore, was "locked in" to the resource selections for the following reasons:

- A build plan excluding CVR, instead allowing selection of the next least-cost resource available, resulted in higher NPV costs in each scenario base case; and
- Aurora would not allow economic selection of a resource in 2020 if no capacity need exists in that year.

Q. Please explain Exhibit A-9 (STW-6).

A. Exhibit A-9 (STW-6), lines 1 through 6, column (b), provides the economic benefit of allowing the CVR Program to begin a ramp up starting in 2020, even if the capacity need does not require it (the comparison was taken to the base case sensitivity in each scenario). A negative value represents projected customer *savings* from an NPV perspective of including CVR in the portfolio, as opposed to selection of other resources. The only instances in which CVR does not provide savings is in the EP scenario under the AEO gas price outlook. In this scenario, when CVR was removed from the portfolio of resources, selection of storage to replace the CVR resulted in avoiding a fixed-sized DR program.

The "right-sizing" of storage resources in the sensitivity with no CVR was ultimately a slightly lower-cost option for customers. Clearly, there are limited and specific scenarios where CVR is not an economic choice for customers; in this case, the inflexibility of an aggregate DR program. In each of the other five scenarios, however, Exhibit A-9 (STW-6) projects significant customer savings with the inclusion of CVR as part of the portfolio. The favorable economics presented in this exhibit represent the costs of CVR, including with a shared savings incentive mechanism, compared to other resource alternatives offered in this IRP. Additional discussion of a CVR incentive mechanism is provided in the testimony of Company witness VanSumeren.

<u>Demand Response</u>

Q. Please describe the source of DR programs offered into Aurora.

A. The Company expects to provide approximately 607 MW of DR reductions by 2022. Expansion beyond 2022 levels were evaluated in this IRP, based on both the 2017 DR potential study conducted by AEG ("AEG DR potential study") as well the Company's own 2020 potential study ("CE DR potential study").

Q. Please describe the DR program offered into AEO gas scenario optimizations, based on the AEG DR potential study.

A. The DR aggregate resources offered to Aurora in this IRP were developed based on an allocation of the total potential determined in the AEG DR potential study to Consumers Energy's service territory. The direct testimony of Company witness Robert L. Fratto, in the Company's 2018 IRP filing, MPSC Case No. U-20165, describes the allocation of the DR potential from the AEG DR potential study to Consumers Energy and the DR cost assumptions in the AEG DR potential study.

Similar to the approach taken in Case No. U-20165, a "low" and a "high" prototype were developed from the AEG DR potential study for selection in this IRP. The "low" prototype provided for a total of approximately 1,200 MW of DR expansion, or about 600 MW above and beyond the Company's 2022 target. The "low" prototype was offered into the BAU AEO scenario. The "high" prototype, which was offered into the EP AEO and ET AEO scenarios, provided for nearly 1,800 MW of total DR expansion, or approximately 1,200 MW above and beyond the 2022 target.

For modeling purposes, all costs associated with incremental DR are assumed to be O&M-related. In reality, there will be some capital investments required to achieve the levels offered in the various portfolio optimizations. Costs for DR were offered into Aurora on a levelized cost basis, with two separate blocks for the "low" prototype, applicable to the BAU AEO scenario, starting at $53/kW-year (2020 dollars) and the second at $64/kW-year, both escalating at 2% each year. In the EP AEO scenario, three "high" prototype blocks were offered; the first block started at a levelized cost of $57/kW-year, the second at $67/kW-year, and the third at $76/kW-year, all three escalating at 2% per year. Finally, in the ET AEO scenarios, a reduction of DR costs at 35% lower than BAU is required. This resulted in the three "high" prototype blocks in ET AEO corresponding to levelized costs of $37/kW-year, $44/kW-year, and $49/kW-year, respectively. The basis for offering the higher levels into ET AEO and EP AEO is that those are the worlds in which advances in technologies are coupled with potentially higher energy prices, which could result in increased customer interest in DR, resulting in higher levels of DR compared to what is currently considered a reasonable amount of reliance.

Exhibit A-10 (STW-7) presents a graphical presentation of the levels of DR offered into each scenario and the corresponding size of the programs Aurora was able to select. Page 1 shows the two DR blocks offered into the BAU AEO scenario; and page 2 shows the block offered into ET AEO and EP AEO.

Q. Please describe the DR program offered into the Consumers Eneregy gas scenarios, based on the Company's own potential study.

A. The aggregate DR resource offered into Consumers Energy scenarios (BAU CE, ET CE and EP CE) was developed based on data extracted from the 2020 DR potential study conducted by Demand Side Analytics. Details of that study are provided in the direct testimony of Company witness McGraw. The study projects a total potential of approximately 1,088 MW of total DR, or about 480 MW above and beyond the 2022 levels. Each of the three Consumers Energy scenarios mentioned above were evaluated with the full potential offered for selection.

In the Aurora selection simulations, the 480 MW of incremental DR was allowed to be selected in six different blocks or "tranches." (See Exhibit A-10 (STW-7)). Each tranche corresponds to an incremental cost increase, such that a certain amount of DR was available at a given price, and for Aurora to add more DR, the next tranche would come at a higher price. In this way, the model can add incrementally higher levels of DR, until the resource is no longer economical. The CE scenario tranches were on average 45 MW each, in size,[11] with the lowest cost tranche offered in at a levelized cost (in 2021 dollars) of $75 per kilowatt-year, increasing by $10 per kilowatt, to $115 per kilowatt-year for the fifth tranche, and the sixth and final tranche priced at the weighted average of the highest

[11] The exception to this average size of the DR blocks is the last block, which was an aggregate of all DR above $120/kW-year (2021 levelized dollars)

cost programs - $166 per kilowatt-year. Page 3 of Exhibit A-10 (STW-7) presents the amounts of DR available at the increasing costs, up to the total of all six tranches.

The operating parameters modeled for DR assume that any incremental amounts picked will be operated as an aggregate resource, with an ability to call upon the resource to meet customer demand no more than forty hours per year. Sensitivities were performed in both the Company's capacity sufficiency analysis as well as risk analysis to evaluate the impacts on both customer cost as well as electric supply reliability. These sensitivities were an investigation to determine the impact to customer costs and supply reliability if DR was only available ten hours per year as well as if DR did not respond when called upon at all – effectively, if DR was available zero hours per year. The selection of which 10 or 40 hours per year to call upon DR was made within Aurora's long-term capacity expansion or zonal simulations, based on the highest demand hours, while considering generating resource unit operating constraints.

Q. How does the resource plan for DR in the PCA compare to the portfolio optimizations results from Aurora?

A. In many of the scenarios and sensitivities under both DR potential studies, DR was selected in the LTCE simulations in discreet blocks, based on the price-based tranches described above. In some cases, large amounts of DR programs were selected in specific years, based on capacity need timing. However, as discussed in Section V, above, the LTCE model results were used to give an indication of what *types* of resources provided the lowest cost to customers, and with timing of the additions to a lesser degree. In fact, in many optimization portfolios, DR was added incrementally over time to capture a realistic and feasible expansion of customer-driven programs. Specifically, the additions of DR included in the glide path portfolios discussed in Section VIII and in the PCA provide a gradual ramp of DR over a number of years. This approach affords the Company the flexibility to carefully implement DR in the most efficient way for customers. As DR grows within the state of Michigan, the Company's PCA offers scalability based on its experience with operation of DR as a large-scale capacity resource and adaptability to any potential changes to the treatment of DR as a capacity resource within the MISO regional markets.

The selection of DR, as presented in the PCA, corresponds to incremental additions above 2022 levels. This plan represents contribution to the PRMR from DR of approximately 10%. The validity and reasonability of the 10% share of capacity requirements is supported in the testimony of Company witness McGraw.

Energy Waste Reduction

Q. Please describe the EWR programs offered into Aurora.

A. A variety of increasing levels of EWR savings were evaluated for expansion in this IRP. In all scenarios, and per the EWR filings made in MPSC Case No. U-20372, the Company will achieve EWR reductions of 2.0% of prior year sales 2021-2023. Below are the levels considered in the various scenarios and sensitivities included in this IRP for the remainder of the study period:

- The Consumers Energy scenario base case assumes 1.0% cumulative EWR savings growth for years 2024-2040.
  - Expansion up to levels identified in the 2020 EWR potential study was offered as a prototype for selection in all Consumers Energy scenarios. Additional details regarding the potential study and proposed expansion of base case EWR can be found in the direct testimony of Company witness Steven Q. McLean.
- The MPSC scenario base case assumes 1.5% cumulative EWR savings growth for years 2024-2040.

- Expansion to 2.0% for years 2024-2040 was offered as a prototype for selection in most MPSC scenarios;

- Expansion of an incremental 0.25% for years 2031-2040 (for a total of 2.25% for years 2031-2040) was also offered as a prototype for selection in most MPSC scenarios.

- A sensitivity of EWR is included in each of the MPSC sensitivities:

  - Expansion of EWR to 2.5% over four years and remaining at that growth level throughout the study period.

Like the CVR Program, EWR expansions selected by the model are assumed to begin in 2024 regardless of the first year of capacity need. This allows EWR to deliver higher levels of peak demand reductions to fill significant capacity shortfalls. Therefore, similar to the CVR option, EWR expansions were "locked in" to the optimization selections for the following reasons:

- The LCOE, shown in Exhibit A-7 (STW-4) for EWR is relatively competitive with other resources;

- EWR provides a significant amount of energy reduction; using terms applicable to supply-side resources, EWR has a 75-80% capacity factor, providing material energy *value*;

- Exclusion of EWR, in lieu of other available supply and demand-side resources was evaluated as an LTCE simulation in Consumers Energy scenarios and shown to both increase and decrease NPV costs in the three scenarios evaluated, indicating EWR as a relatively marginal resource compared with the alternatives; and

- Aurora would not allow economic selection of a resource in 2024 if no capacity need exists in that year.

Q. Please discuss how the economic evaluation of EWR is presented in Exhibit A-9 (STW-6).

A. Exhibit A-9 (STW-6), lines 1, 3, and 5 in column (c), provide the economic benefit of locking in the EWR Program starting in 2024 versus excluding the expansion. A negative value represents projected customer savings from an NPV perspective by the inclusion of

EWR. In this IRP, the Company seeks approval of the expansion of EWR according to the Consumers Energy 2020 EWR potential study (and not the 2017 potential study); therefore, the economics of the EWR prototypes included in MPSC scenarios were not evaluated.

Q. Company witness McLean discusses an update made to the EWR forecasts included in modeling. Please explain how these updates were handled.

A. As discussed in the testimony of Company witness McLean, the EWR forecast was updated late in the modeling process. The update resulted in significant reductions in projected customer costs due to substantial increases in the benefits that the EWR expansion programs would provide. Specifically, the original EWR outlooks included in the modeling materially understated both the peak demand reductions and avoided annual generation requirements resulting from both base levels and expansion of EWR. Since this update was identified late in the modeling process, it was not feasible to update most of the scenario and sensitivity modeling. Instead, the update to the EWR base levels and expansions in the Consumers Energy scenarios were included in the modeling of the PCA and alternate plan. A new load forecast was input to Aurora, resulting in a reduction of resources necessary to meet the PRMR in the PCA and alternate plan.

Q. How does the resource plan for EWR in the PCA compare to the portfolio optimizations results from Aurora?

A. The PCA includes expansion of EWR up to the levels identified in the Consumers Energy 2020 EWR potential study. EWR is proposed to continue its expansion to nearly 2% of prior year sales through the 2020s; beyond 2030, the study identifies potential levels only achieving approximately 1% cumulative of prior year sales in the remaining years of the study period.

SECTION VIII: OPTIMIZATION PORTFOLIOS

Q. In Section V of your testimony, you explained that combinations of resources are offered into the Aurora model for selection. Please explain how these combinations are designed, prior to Aurora resource selections.

A. The term "design" is in reference to how the various portfolios were constructed for optimization modeling within Aurora. The design process encompasses some of the modeling constraints that may be input to Aurora in order to obtain a particular type of portfolio resource mix. For example, to develop one portfolio design that considers the addition of new peaking capacity only, constraints were entered into the Aurora model to prevent the optimization logic from adding any new resource options other than new gas-fueled simple cycle CTs. Similarly, some modeling constraints were "loosened" in order to evaluate other portfolio designs. Examples of the types of parameters that were varied with the construction of different portfolio designs include: resources available for selection, maximum reserve margin requirement, and minimum or maximum allowable numbers of a resource to be built in a given year or throughout the planning period.

Q. What are the portfolio designs that were considered in this IRP?

A. A total of ten portfolio designs included in the Aurora optimizations are presented in Exhibit A-11 (STW-8). Portfolios 1, 2, and 3 were evaluated in nearly all sensitivities; however, there were some sensitivities for which some of the three of those portfolios were not necessary, and the NPV result is not presented in Exhibit A-12 (STW-9), discussed later in this direct testimony.

- The first portfolio design, referred to as Portfolio 1, is a portfolio mentioned in Section VI of this direct testimony as the hypothetical capacity replacement in which other MISO market participants may have capacity available for sale from existing and new generating facilities. Portfolio 1 represents a portfolio in which all required incremental capacity can be purchased on a short-term or spot basis at a forecasted market capacity price. The market price of capacity is assumed to be 75% of CONE. With this particular portfolio design, there is effectively only one resource option for each scenario and sensitivity case, the market purchase of ZRCs. The revenue requirements include the spot market capacity expense and the spot market energy expense for all economy energy purchases.

- A second portfolio design, Portfolio 2, represents a scenario in which Aurora may select any and all supply or demand-side resources to meet the Company's demand and reserve margin requirements. Given the variety of technologies available and the period being studied, multiple resource plans are generated and each resource plan is ranked by the corresponding NPV. In some scenarios, Portfolio 1 may provide a lower revenue requirement than Portfolio 2. In other scenarios, the opposite outcome may result, depending on the relative cost of available supply- or demand-side resources versus the assumed cost of market purchases. In general, the more options offered to the Aurora optimization, the lower the NPV cost. Since Portfolio 2 offers all supply- and demand-side options in the optimization, it can be considered the full optimization performed on each scenario and sensitivity; however, in this portfolio, the long-term capacity expansion simulation results in a resource plan that assumes an "overnight build" of resources. For an illustrative example, consider an LTCE simulation on a sensitivity in which there is no capacity need until 2030; the LTCE would likely add no resources until selecting, perhaps, 3,000 MW of solar to be brought online "overnight" in a single year, 2030.

- Portfolio 3 is referred to as the "glide path" portfolio design and results in what is later referred to as the "optimal plan" of any given scenario or sensitivity. Upon completion of the LTCE simulation in Aurora, which is provided by Portfolio 2, a glide path optimization portfolio was created post-processing and evaluated as a zonal run in Aurora. A zonal run differs from an LTCE run in that a zonal run is not *selecting* new resources like an LTCE does. Instead, a zonal run will perform a production cost simulation on a completed selection of resources, already sufficient to meet peak demand plus required reserve margins. As discussed in Section VI of this direct testimony, as well as in the testimony of Company witnesses Battaglia and McGraw, many of the resources included in this IRP require significant lead time and/or may be limited by feasibility constraints. Examples include the lead time required to enroll customers in demand response programs in order to provide a significant amount of zonal resource credits to serve the PRMR, or the feasibility limitations of adding gigawatts of solar capacity in a single year. In the glide path portfolio, resources are added incrementally, over a number of years, to ensure that when needed and selected in the LTCE, the resources provide sufficient ZRC to enable retirement of an existing resource or expiration of a PPA. This "glide path" of incremental addition of supply capacity or growth of a program over time means that resources may be added prior to the year of need. Development of the glide path is completed in Excel and is based on the outputs of the LTCE. The glide path would consider all resources selected, and apply feasibility constraints. Returning to the illustrative example discussed above, instead of waiting until 2030 to add solar resources, the glide path optimization portfolio will begin adding solar capacity as soon as possible, 2025, in this case, and ramp up the solar capacity additions steadily over time – 500 MW each year through 2030, to meet the required 3,000 MW target. Portfolio 3, the glide path portfolio, is the basis of all economic comparisons presented for all scenarios and sensitivities in this IRP. Economic results presented throughout this IRP regarding economic analyses generally represent the difference between the NPV of the glide path optimization portfolio of a given sensitivity versus the NPV of the glide path optimization portfolio for the base case in that scenario.

- Portfolio 4 is the Company's preferred plan, or PCA. The PCA is described in detail in the direct testimony of Company witness Blumenstock and is also discussed in Section X of this direct testimony, from a modeling perspective. The PCA can also be reviewed in Exhibit A-14 (STW-11). The PCA is a glide path portfolio, but is a specific fixed capacity replacement portfolio, meaning once the resource selection was determined, the resources were locked into the Aurora simulations for evaluation as zonal runs. In Exhibit A-11 (STW-8), lines 4 through 10, columns (e) and (f) are checked off for the PCA, indicating what type of portfolio the PCA is – it is not an LTCE, it includes no market purchases; it's a glide path portfolio that can be *fixed* for evaluation in many scenarios or sensitivities. The PCA was evaluated on all MPSC-required sensitivities and on all base scenarios for which it provided sufficient resources. That is, since the PCA is a fixed portfolio of resources, in some cases, those resources would be insufficient to meet the PRMR of a given sensitivity and, therefore, there it is not reasonable to evaluate Portfolio 4 on that sensitivity. Specifically, Portfolio 4 was evaluated on nine sensitivities: the retirement base case of all seven scenarios, not including AT (which has a different PRMR) as well as the high gas price sensitivities included in BAU AEO, ET AEO and EP AEO.

- Portfolios 5 through 10 were developed as part of the Company's risk assessment and are each glide path portfolios as well as fixed portfolios, as indicated in columns (e) and (f) in Exhibit A-11 (STW-8). Portfolio 5 represents the optimal portfolio (Portfolio 3) from the BAU CE retirement base case sensitivity. As explained in the testimony of Company witness Munie, the optimal plan from each scenario was evaluated under the remaining two scenarios for which the resource plan meets the PRMR. Table 2 of Exhibit A-11 (STW-8) presents a visual tally of these optimal portfolio evaluations. Portfolio 5, the BAU CE optimal plan was evaluated under ET CE and EP CE scenarios, as checked on line 12 in columns (d) and (e).

- Likewise, Portfolio 6 represents the optimal portfolio from the ET CE retirement base case sensitivity and was evaluated on the retirement base case in BAU CE and EP CE (see line 13, with checks included in columns (c) and (e)).

- Portfolio 7 is the optimal portfolio from the EP CE retirement base case sensitivity and evaluated on the retirement base case in BAU CE and ET CE (see line 14 columns (c) and (d)).

- Portfolio 8 is the optimal portfolio from the BAU AEO retirement base case sensitivity and evaluated on the retirement base case in ET AEO and EP AEO (line 15 columns (g) and (h)).

- Portfolio 9 is the optimal portfolio from the ET AEO retirement base case sensitivity and evaluated on the retirement base case in BAU AEO and EP AEO (line 16 columns (f) and (h)).

- Finally, Portfolio 10 is the optimal portfolio from the EP AEO retirement base case sensitivity and evaluated on the retirement base case in BAU AEO and ET AEO (line 17 columns (f) and (g)).

The Alternate Plan was not included as an optimization portfolio, but is included as Portfolio 3 under a BAU CE sensitivity. A dedicated portfolio was not created, as was done for the PCA because the Company is not seeking approval to execute the alternate plan and therefore did not evaluate it across all applicable scenarios and sensitivities.

Q. Is the mix of resources selected for a given portfolio design the same across all scenarios and sensitivities?

A. For fixed portfolios, Portfolios 4 through 10, yes, the resource mixes will be the exact same in those optimization portfolios for all scenarios and sensitivities. Those resource mix selections are provided in graphical format in Exhibit A-14 (STW-11).

Portfolio 1, in which capacity and energy market purchases are made to meet customer demand, may vary in certain sensitivities. For all AEO gas scenarios and sensitivities except the 1.5% load growth, 50% ROA Return, and 2.5% EWR Growth sensitivities, Portfolio 1 will be the same. That is, the amounts of purchased capacity from the market is the same for all scenarios and sensitivities not listed. For Consumers Energy gas scenarios, particularly sensitivities evaluating early retirement of existing assets, different amounts of purchased capacity are needed to meet customer demand.

For Portfolios 2 and 3, the resource plan selected will likely not be the same across all scenarios and sensitivities. The combination or set of resources offered into the optimization was generally preserved across all scenarios and sensitivities. However, for a given portfolio design, the resulting resource plan or mix (e.g., timing, technology, amounts) will likely differ from scenario to scenario as a result of differences in input assumptions for each scenario. For example, Portfolios 2 and 3 would likely include a greater number of new gas-fueled capacity additions added through year 2040 in the BAU CE gas scenario than in the BAU AEO gas scenario due to substantially higher gas prices in the AEO gas scenario, which makes gas-fueled generation much less economic. In this example, while resources offered (e.g., timing, technology, and amounts) is the same for both scenarios, the selection of and amounts of new gas-fueled generation added are different. For the same reasons mentioned above, we would reasonably expect for a given portfolio design, the NPVs will vary for each of the different scenarios and sensitivities.

SECTION IX: PURCHASED GAS UNIT OPERATIONS

Q. The Company's PCA requests approval of the purchase of two natural gas asset groupings, offered through a request for proposals ("RFP") process described in the testimony of Company witness Troyer. What information regarding those natural gas assets are you discussing in your testimony?

A. I will discuss the operating characteristics and projected generation of the natural gas assets, as modeled in this IRP. I will present information in exhibits for the total annual average cost of the units; availability factors (scheduled and forced outage rates); type of operation cycle; hours of operation projected per year; projected start-ups per year; cycling conditions per year; and annual heat rates based on projected operation.

Q. What are the specific natural gas-fueled generating units included in your testimony?

A. As introduced in the testimonies of Company witnesses Blumenstock and Troyer, I will be discussing the parameters identified above for the following generating units: the Covert combined cycle gas plant, the Dearborn Industrial Generation ("DIG") combined cycle and peaking units, the Kalamazoo River Generating Station peaking plant, and the Livingston Generating Station peaking plant.

Q. What are the assumed operating characteristics of the aforementioned units?

A. The operating characteristics are summarized for each gas unit in Exhibit A-15 (STW-12) on pages 1 through 4. Information provided in this exhibit includes maximum capacity, minimum capacity, summer capacity derations, ZRCs, type of operation cycle, scheduled outage rates, forced outage rates, variable operating and maintenance costs included in dispatch, input heat rates as various dispatch blocks, as applicable, and emission rates.

Q. What are the forecasted levels of operation for the gas units?

A. Page 5 of Exhibit A-15 (STW-12) provides projected output generation in megawatt hours ("MWh") on lines 1 through 15, projected hours of operation on lines 16 through 30, and projected capacity factors on lines 31 through 45. Page 6 summarizes the resulting annual average costs[12] of the plants on a dollar per MWh basis on lines 1 through 4, with the underlying delivered fuel costs on lines 5 through 9. Page 7 provides the projected number of start-ups per year on lines 1 through 15 and the resulting net heat rates on lines 16 through 30, based on the projected output of the plants.

[12] Annual average costs provided in this exhibit include fuel costs, start-up costs, emissions costs, variable operating costs, fixed operating costs and on-going capital.

The total annual average costs provided in Exhibit A-15 (STW-12), page 6, were calculated based on the fuel costs presented in the direct testimony of Company witness Gallaway and based on the fixed and variable operating costs found in the direct testimony of Company witness Kapala.

SECTION X: SUMMARY OF MODELING RESULTS

Q. Please explain how the IRP results are summarized.

A. Results of the Aurora modeling are provided in three exhibits.

- Exhibit A-12 (STW-9) provides the NPV economic results of the multitude of scenarios, sensitivities, and portfolios;
- Exhibit A-13 (STW-10) demonstrates the amounts and timing of each *type* of new technology resources selected amongst the multitude of scenarios, sensitivities, and portfolios; and
- Exhibit A-14 (STW-11) provides a graphical summary specific to the exact amounts, timing, and types of new technology resource selections in each of the eight scenarios, under the retirement base case assumptions and with the addition of the proposed purchase of natural gas capacity. This exhibit also includes the details of resources included in the PCA and alternate plan.

NPV Economic Results

Q. Please discuss how the NPV economic results are summarized.

A. The NPV results are summarized by comparing the economics of the multiple portfolios defined in Section VIII of this direct testimony. As outlined above, eight future scenarios and multiple sensitivities were evaluated for a combined total of 86 scenarios and sensitivities in the IRP using Aurora. For most scenarios and sensitivities, Portfolios 1 through 3 were constructed and considered to assess the relative economics and risks of different resource combinations, timing, and amounts. As discussed in Section VIII, Exhibit A-11 (STW-8) provides a summary of the ten portfolio designs.

Q. What are the NPV results of the IRP scenario modeling?

A. The results of the IRP scenario modeling are presented in Exhibit A-12 (STW-9). This exhibit provides NPV costs (in millions of dollars) for whichever of the ten portfolio options that were applicable to meet the Company's capacity needs between 2020 through 2040.

Page 1 of Exhibit A-12 (STW-9) contains results for Portfolios 1 through 7 on lines 1 through 7 for all sensitivities evaluated under BAU CE Gas scenario. Each of those sensitivities is listed in columns (a) through (p). Beginning on line 8, the delta for each sensitivity is calculated as the difference between the NPV result of the sensitivity minus the NPV result of the base case, found in column (a). This difference is taken for each portfolio. For example, consider column (d), lines 8 through 10. Column (d) line 8 represents the difference between the Portfolio 1 NPV result of the Campbell 1 2026 retirement sensitivity and the Portfolio 1 NPV result of the base case; line 9 represents the difference between the Portfolio 2 NPV result of the Campbell 1 2026 retirement sensitivity and the Portfolio 2 NPV result of the base case; and so on. Page 2 provides similar information under the ET CE Gas scenario; and Page 3 provides similar information under the EP CE Gas scenario. While most columns on lines 8 through 10of these three pages provide the delta to the base case, there is an exception, which occurs in columns (o) and (p). Column (o) contains no deltas; column (p), line 10 calculates the difference of the final retirement base case compared to column (o), line 3, which contains the NPV result of the alternate plan.

Similar information is presented on pages 3 through 6 for NPV results and deltas under the AEO gas scenarios. Page 4 presents NPV results and deltas for all sensitivities evaluated on the BAU AEO Gas scenario; page 5 includes NPV results and deltas for sensitivities evaluated on the ET AEO Gas scenario; and page 6 includes NPV results and deltas for the EP AEO Gas scenario. Note that Portfolios 1 through 4 are included on pages 4 through 6, but portfolios 5 through 7 are not; instead, Portfolios 8 through 10 are included on lines 5 through 7. That is because Portfolios 5 through 7 were not evaluated on MPSC scenarios and sensitivities since the optimal plans corresponding to those portfolios were not applicable to meet the PRMR of the MPSC scenarios and sensitivities. Likewise, Portfolios 8 through 10 were not applicable for CE scenarios and sensitivities.

Page 7 of Exhibit A-12 (STW-9) includes just two sensitivities evaluated under the AT scenario. These are shown in columns (a) and (b), with Portfolios 1 through 4 results and deltas listed on lines 1 through 4 and 5 through 8. The PRMR of AT scenarios and sensitivities was significantly different than any other scenarios; therefore, no additional portfolios were evaluated on AT scenarios and sensitivities.

Finally, page 8 of Exhibit A-12 (STW-9) provides results for the single sensitivity evaluated within the Carbon Reduction scenario. This sensitivity only includes results for Portfolios 1, 2, and 3, shown on lines 1 through 3. For comparison purposes, the retirement base case sensitivity under EP AEO assumptions is included; lines 5 and 6, column (b) provides the cost increases associated with the 1.5% load growth assumption.

The NPV values presented on pages 1 through 8 of Exhibit A-12 (STW-9) correspond to results assuming excess capacity can be sold to reduce customer costs at a capacity price of 75% of CONE. In reality, the Company acknowledges the long-term value of capacity will likely vary, potentially from year-to-year. Furthermore, when making decisions with these NPV results included in consideration, the Company acknowledges the risk of natural gas price variability as well. Therefore, results of the sensitivities presented in Exhibit A-12 (STW-9) were evaluated across a range of potential gas prices and capacity prices. In this way, the Company considers not just a discreet NPV result and corresponding delta of a given sensitivity, but instead, can understand the *range* of possible outcomes, given the unpredictable nature of both natural gas and capacity price outcomes. Because these ranges of NPV values support the decisions included in the Company's PCA, which are discussed in the direct testimony of Company witness Blumenstock, the graphical results of the gas and capacity NPV result deltas to the base case are found in Figures 9 and 10 in the direct testimony of Company witness Blumenstock. Figure 9 presents the difference in the Portfolio 3 NPV result of each retirement sensitivity and the Portfolio 3 NPV result of the base case. The range of NPV values are shown in green shading if the difference is negative, resulting in customer *savings* compared to base; or in red shading if the difference is positive, resulting in *increasing* customer costs compared to base. In total, there are twenty NPV data points included in these ranges: an NPV value for four different gas prices (25% below base gas price, base gas price, 25% above, and 50% above) and five different capacity prices (0% CONE, 25%, 50%, 75%, and 100% CONE). A discreet NPV value is called out in the figure that corresponds to the NPV at base gas prices and at both 0% CONE and 75% CONE. There are also bars, or "whiskers," included within the bars of the figure, which correspond to the range of NPVs resulting from the *gas price sensitivities* performed at each capacity price step indicated. Figure 10 in the testimony of witness Blumenstock makes a similar comparison of the PCA to the alternate plan.

Q. Please discuss any significant observations of the results of the sensitivities listed in Exhibit A-12 (STW-9).

A. A few significant observations of the sensitivity modeling are as follows:

- Pages 1 through 3 of Exhibit A-12 (STW-9) provide the results of the Consumers Energy unit retirement analyses assuming surplus capacity is sold at 75% CONE; however, further discussion and the more robust NPV results (including natural gas and capacity price sensitivities) are presented as figures in the direct testimony of Company witness Blumenstock. Because many of the deltas shown on pages 1 through 3, line 12 of Exhibit A-12 (STW-9) are negative, the Company recognized the potential for customer savings under an accelerated retirement of one more Campbell units.

- Columns (o) and (p) on page 1 through 3 present the NPVs associated with retirement decisions corresponding to the alternate plan and retirement base case under Consumers Energy scenario assumptions.

- Pages 4 through 6 provide the results of the MPSC scenarios and sensitivities. Column (a) of each of the three pages includes the base case NPV results under the MPSC scenarios described in Section IV of this direct testimony. In column (b), the economics of the retirement decision associated with the alternate plan is presented on each page, with results included in columns (c) through (g) on page 4 and columns (c) through (f) on pages 5 and 6 for the remaining MPSC sensitivities (under the alternate plan retirement assumptions).

- Column (h) on page 4 and column (g) on pages 5 and 6 present the NPV results of the retirement base case under MPSC scenarios. The deltas in MPSC scenarios are generally unfavorable for the retirement base case because of the higher natural gas price forecast assumed in MPSC scenarios.

- Finally, columns (i) through (m) on page 4 and columns (h) through (k) on pages 5 and 6 provide NPV results, under retirement base case assumptions, for the remaining MPSC sensitivities. These results are discussed below.

- The 1.5% load growth sensitivities on the three scenarios – BAU AEO, EP AEO, and ET AEO evaluate the risk of high load growth on these scenarios. The results generally indicate that compared with the base case, the glide path portfolios are approximately $2.5 billion more expensive (line 10, column (i) on page 4, column (h) on pages 5 and 6); meaning that if load grew at 1.5% per year, customer costs on an NPV basis would increase by approximately $2.5 billion. Under BAU AEO assumptions, the high load growth assumptions require the addition of new CT capacity and higher levels of DR, while ET AEO and EP AEO scenarios generally increased the amount of solar and DR.

- The 2.5% EWR sensitivity for the three scenarios evaluates the impact of a significant growth in EWR savings over a relatively short period of time. The results indicate that compared with the base case, if EWR levels were achieved and maintained at 2.5% starting in 2021, under retirement base case assumptions, customer costs would decrease by between approximately $550 million and $750 million NPV compared with the base (glide path portfolio versus glide path portfolio). With greater contributions to serving the PRMR made by EWR, solar expansion declines in BAU AEO and ET AEO; in the EP AEO scenario, the reduction in selection of solar is significant, with replacement of DR in lieu of solar.

- Exhibit A-12 (STW-9) column (l) on page 4 and column (k) on pages 5 and 6 presents the results of the sensitivity evaluating the impacts of increasing AEO gas prices to two times base gas prices by the end of the planning period for all three scenarios. The results indicate that if gas prices increased to 200% of AEO base gas prices by 2040, the glide path portfolios would increase by between $1.5 billion and $2.2 billion NPV compared with retirement base case glide path portfolios. The Company sees the gas prices in this sensitivity as falling outside the range of reasonable possibilities;

- Page 4, column (j) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluate impacts due to return to bundled service of 50% of customers currently taking service from an alternative energy supplier. Under this sensitivity, additional capacity and energy needs would be required, compared to the retirement base case, which would increase costs by approximately $1 billion in the glide path portfolios. The higher PRMR would require more resources, and the Aurora selected plan in this sensitivity chose additional solar and storage to make up the higher shortfalls.

- Page 4, column (m) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluated filling future capacity needs with only CTs. If the resource mix was limited to expansion with only CT resources, NPV costs would increase by $365 million compared to the retirement base case glide path portfolio.

- Exhibit A-12 (STW-9), page 5, column (i) presents the results of the sensitivity that evaluated an increased renewable portfolio standard to 25% by 2030, under the ET scenario. However, the Company's retirement base case sensitivity already achieves this target; therefore, there is no NPV delta for this sensitivity versus the retirement base case glide path portfolio.

- Page 6, column (l) of Exhibit A-12 (STW-9) presents the results of the sensitivity that evaluated a reduction of CO_2 emissions of 50% by year 2030, under the EP scenario. Once again, the retirement base case glide path portfolio achieved this goal, therefore, there is no NPV delta for this sensitivity.

- On page 7, NPV results under AT scenario assumptions are presented for the retirement base case. In this scenario, the addition of the existing natural gas assets is offsetting the addition of distribution-connected solar and battery storage, which is assumed at 50% below BAU costs. Under such dramatic reductions in capital costs for these resources, the displacement by the gas units results in a $578 million NPV increase.

- Finally, page 8 of Exhibit A-12 (STW-9) presents the NPV results of the Carbon Reduction scenario. This scenario is loosely based on the EP AEO scenario, with the addition of a high load growth assumption, a 28% CO2 reduction target by 2025 (compared with 2005 levels) as well as a 32% CO2 reduction target by 2025. The Company's retirement base case sensitivity achieves both of these CO2 reduction goals, therefore column (a) on page 8 matches exactly with column (g) on page 6. Column (b) of page 8 includes the high load growth assumption as well as the final requirement of the Carbon Reduction scenario, which is to include the PCA as the starting point of the capacity replacement plan. Due to the high load growth assumption, additional resources were required to meet the PRMR; Aurora selected additional solar and storage to fill the higher shortfalls. Customer costs under these assumptions increase by $1.4 billion compared to the retirement base case.

Q. Are there any additional sensitivity results you will discuss in your testimony?

A. Yes. The final set of sensitivity analyses discussed in this testimony include qualitative observations from sensitivities evaluating: 1) the Company's assumed discount rate; 2) the impacts of changes to solar ELCC; and the 3) resource selection changes due to higher transmission network upgrade costs.

Q. Please discuss the results of the sensitivity evaluating an alternate discount rate.

A. The first sensitivity evaluates impacts on changes to the Company's assumed discount rate. Specifically, a rate of 2.5% was evaluated, compared to the base assumption of 7.5%. The scope of this analysis included the impact to net present value results, particularly the *delta* of NPVs, which are the primary metrics for the economic analyses used in this IRP. The analysis did not include identification of different resource selections under an alternate discount rate, nor did it consider impacts to customer rates or revenue requirements, or utility financials.

The primary observations from the analysis are that: 1) a lower discount rate will increase the total NPV of a portfolio of resources as future year costs are discounted less; 2) a lower discount rate may improve the economic outlook of some new technology resources or customer programs when evaluated in isolation (for example, the levelized cost of energy of the resource could be lower under the lower discount rate); and 3) the magnitude of the delta of NPVs between two sensitivities will likely grow under a lower discount rate (for example, projected savings of an accelerated retirement sensitivity versus base will likely be greater at a 2.5% discount rate versus a 7.5% discount rate).

The Company's interpretation of these observations is that a lower discount rate would appear to result in no changes to the set of decisions that are included in the PCA. Another important observation is that utilization of a lower discount rate in NPV analysis ascribes a greater value to projected customer savings that will be experienced by future customers when compared to NPV analysis utilizing a higher discount rate, which would ascribe more value to near-term savings.

Q. Please discuss the results of the sensitivity evaluating an alternate assumption of solar ELCC.

A. The MISO publishes an effective load carrying capability value of 50% for new solar capacity (without sufficient historical performance data on which to support the ELCC). However, the potential reduction in ELCC, as solar capacity expansion continues, has been discussed in various stakeholder forums at the MISO. Therefore, the Company has conducted a sensitivity that evaluates the change in resource selections when the solar ELCC gradually declines from current levels of 50% to 30% by 2033. As solar's installed capacity provides for fewer and fewer ZRC to contribute to serving the PRMR, increasing amounts of solar capacity are added (approximately 1,500 MW of additional solar by the end of the study period) as well as significant increases in the addition of battery storage resources (approximately 1,000 MW of additional storage by the end of the study period). The additional solar and storage capacity required comes at an NPV customer cost increase of over $500 million versus a comparable outlook in which solar capacity received 50% ELCC.

The Company's interpretation of these results is that if solar resources receive less credit from MISO for the amount of installed capacity over time, customer costs will likely increase.

Q. Please discuss the final set of qualitative results of sensitivity modeling.

A. The final sensitivity discussed in this section is the evaluation of higher costs associated with transmission network upgrade costs. Additional information regarding network upgrade expense can be found in the direct testimony of Company witness Scott.

In the base case, a 2020 dollar value of $46 per kilowatt is included in modeling and added to the cost of all new resources selected to account for the cost of transmission expansion, to accommodate the added resource; however, as discussed by Company witness Scott, through collaborative discussions with Michigan Electric Transmission Company, LLC ("METC"), a sensitivity was performed using METC's projected network upgrade costs, a 2020 dollar value of $144 per kilowatt. This higher cost of transmission was added only to transmission-connected resources (not distribution-connected resources).

Primary observations of the analysis are that at $144 per kilowatt transmission network upgrade costs (verus $44 per kilowatt), under BAU assumptions of new resource *capital costs*, transmission-connected solar resources are still more economically favorable than higher-capital cost distribution connected solar. However, under a 35% capital cost reduction assumption on solar, as included in the EP and ET scenarios, the differential between transmission- and distribution-connected solar construction cost shrinks and the upward pressure on transmission-connected solar from the higher network upgrade costs results in selection of distribution-connected solar instead of transmission-connected solar.

The Company's interpretation of this analysis is that the price competitiveness between transmission- and distribution- connected solar is relatively narrow, and the "breakeven point," the price at which the overall economic comparison of the resources is equal, is somewhere within the ranges identified. Specifically, results indicated that if the cost of network upgrades – or any other related transmission costs – are higher than forecasted *and* capital costs of renewable assets are at least 35% lower than forecast – distribution-connected resources may be a lower-cost option than transmission-connected resources. The Company is agnostic to voltage level in its competitive solicitation process for solar capacity acquisition. Distribution-connected solar projects compete with transmission-connected solar projects in the same solicitation process; the customer benefits by the selection of the lowest-cost feasible projects, regardless of voltage level.

<u>New Technology Resource Selection Trends and Observations</u>

Q. Please explain how the new technology resource alternative selections are summarized.

A. As discussed in Section VIII of this direct testimony, Portfolio 3, the glide path portfolio, is the portfolio of greatest interest to the Company, as this represents a build plan that is feasible – the addition of incremental amounts of capacity slowly over time, an expansion that allows for the gradual growth of renewable and storage resources and customer programs. Therefore, the summary of Aurora-selected resource selections in Exhibit A-13 (STW-10) will correspond to Portfolio 3.

Exhibit A-13 (STW-10) presents five pages of the graphical results of Aurora's selection of resources across 116 sensitivities. Each page of the exhibit represents the amount of a single new technology resource alternative (in ZRC) chosen in a given year, across all scenarios and sensitivities included in this IRP. Page 1 presents the amount of solar capacity (in ZRC) selected in a given year in all sensitivities; page 2 presents the amount of battery storage ZRC; page 3 presents the amount of DR ZRC; page 4 presents the amount of wind ZRC; and page 5 presents the amount of natural gas ZRC. The dots shown on the graph represent the amount of solar capacity selected in a given year for a *single* sensitivity. The graph also includes a box and whisker format, which outlines the first and third quartiles within a shaded box, with the second quartile indicated with a horizontal line within the shaded box region; the maximum and minimum values with capped lines above and below the box ("whiskers"), and with outliers presented as single data points beyond the box and whisker collection of data points. The mean is indicated with an "x" data marker, also inside the shaded box region. Note that on pages 4 and 5, no shaded box region appears; this is because there were such few selections of wind and natural gas resources across the 116 sensitivities that the quartile values are 0.

Q. What is the purpose of summarizing the Aurora resource selections in graphical format, as presented in Exhibit A-13 (STW-10)?

A. By presenting the amounts of each new technology resource as a collection of data points, it allows one to observe Aurora's affinity for one type of resource or another, by year.

Given the significant number of sensitivities evaluated in this IRP, and more importantly, the varied assumptions of capital or program costs across the eight scenarios – the graphical representations included in Exhibit A-13 (STW-10) allows one to easily identify *trends* in resource selections. For example, it is immediately apparent that Aurora has a higher affinity for solar versus storage, when one compares the height of the box and whiskers presented on page 1 (solar resource selections) versus those presented on page 2 (storage resource selections). It is evident that solar is a more widely selected resource due to more favorable economics; furthermore, the density of data points in each year on page 1 indicates these amounts (shown on the y-axis) were selected in the *majority* of sensitivities, while the more sparse data points in each year on page 2 indicate that some sensitivities selected little or no storage. Similar observations as those made for storage can be drawn for the amounts of demand response, shown on page 3 – while material amounts of DR are selected across the multitude of sensitivities, the selection of DR is not as prolific as for solar. Pages 4 and 5 indicate that wind and natural gas resources were selected in very few sensitivities.

Q. What are the primary conclusions from the resource selections highlighted in Exhibit A-13 (STW-10) as it relates to the resources included in the Company's PCA?

A. The following observations and conclusions were drawn from the Aurora simulated selection of resources:

- EWR and CVR were "locked in," as previously discussed in this direct testimony and, therefore, not included in Exhibit A-13 (STW-10).
- Exhibit A-13 (STW-10) indicates Aurora's affinity for <u>solar</u> across all scenarios and sensitivities;

- When annual constraints on solar were hit (no more than 500 MW per year could be selected in a single year[13]), either demand response or storage were chosen, depending on the underlying assumptions of capital cost of storage or DR program costs.
    - For example, under BAU assumptions on storage and DR, the relatively lower program costs of DR, compared to base storage costs resulted in moderate levels of DR compared to storage. However, under EP assumptions, when solar costs are assumed at 35% below BAU levels, while DR was kept at base levels, storage was selected over DR. Finally, under ET assumptions, when both storage costs and DR costs are assumed to decline to levels 35% below BAU, the resources compete very closely.
- Only under specific assumptions in certain sensitivities were resources such as distribution-connected solar, wind, and natural gas selected.
    - Distribution-connected solar resources were selected in two types of sensitivities. The first is under AT capital cost assumptions for all resources. As discussed in Section IV, the AT scenario contemplated accelerated growth of distributed energy resources and assumed a 50% capital cost reduction on distribution-connected solar compared to BAU, while transmission-connected solar was assumed at levels 35% below BAU. In the AT scenario, distribution-connected solar was selected in lieu of transmission-connected solar.
    - The second sensitivity in which distribution-connected solar was widely chosen was in the sensitivity evaluating higher transmission network upgrade costs, as discussed in the above portion of this direct testimony, “NPV Economic Results”.
    - Wind resources were only selected in few sensitivities with a 2024 capacity need, which corresponds to wind PTC levels at 60%.
    - New natural gas unit capacity was selected in the BAU CE scenario; while this resource technology may have provided the least-cost portfolio, the Company has decided not to include the construction of fossil-fueled resources in its IRP, as discussed in the testimony of Company witness Blumenstock. However, the BAU CE scenario indicates that natural gas resources provide customer value, as one of the first-selected resources, particularly for needs prior to 2026.
- Behind-the-meter-generation was included in sensitivity analysis, but not as a resource available for *selection.* Therefore, BTMG is not included in Exhibit

[13] Refer to the direct testimony of Company witness Battaglia for more information regarding this constraint.

A-13 (STW-10). Instead, BTMG was a "locked in" resource in specific sensitivities to understand which resources would be "kicked out" of selection. Generally, the customer-owned solar programs tend to reduce the amount of transmission- or distribution-connected solar resources, or battery storage resources.

New Technology Resource Selections in Retirement Base Case Optimal Plans

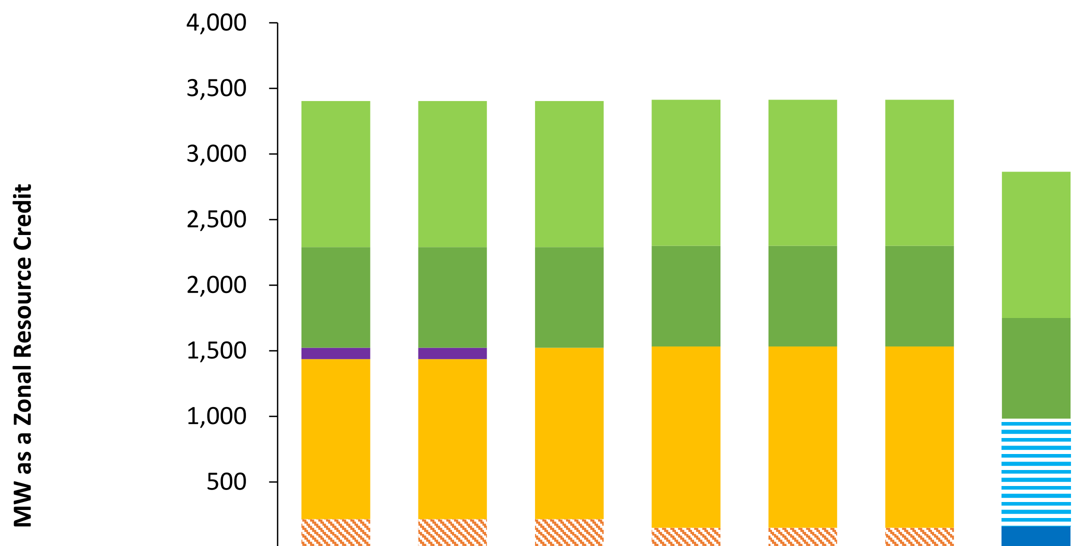
Q. The Company's PCA includes accelerated retirement of Campbell Units 1-3 and Karn Units 3&4 and the addition of two existing natural gas assets. Please discuss the Aurora optimal plan resource selections corresponding to that sensitivity in the applicable scenarios.

A. As discussed in Section VIII, the PCA, Portfolio 4, is a fixed resource plan. However, Portfolio 3, the optimal glide path portfolio was evaluated for the sensitivity considering retirement of the aforementioned resources. The specific build plan, Portfolio 3, corresponding to the accelerated retirement of Campbell Units 1 through 3 in 2025 and Karn Units 3 and 4 in 2023 and the addition of approximately 2,000 MW by 2025 of existing natural gas capacity under each scenario is presented in Exhibit A-14 (STW-11). This exhibit presents a graphical display of the resources selected as the optimal plan, with a summary table below the chart. The first eight pages of this exhibit shows the glide path optimal plan (Portfolio 3) for the retirement base case sensitivity under each of the eight scenarios; page 9 shows the same format of information for the final PCA, while page 10 shows the alternate plan.

Q. How were the results of the long-term capacity expansion runs, and the corresponding selection of resources by Aurora used to inform the decisions made regarding which resources to include in the PCA?

A. Development of the PCA required the selection of capacity resources to fill the needs remaining after the addition of the existing natural gas unit capacity, as supported in the testimony of Company witness Blumenstock. The addition of the gas capacity resolved capacity needs through 2030, following the accelerated retirement of Karn Units 3 and 4 and Campbell Units 1 through 3. The first significant shortfall of capacity would occur in planning year 2030, following the expiration of the MCV PPA. Figure 4, below, provides the graphical summary of Aurora-selected resources in year 2030 for the retirement base case sensitivities across all 7 scenarios (excluding the CO2 reduction scenario):

Figure 4: Retirement Base Case Aurora-Selected Resources by 2030



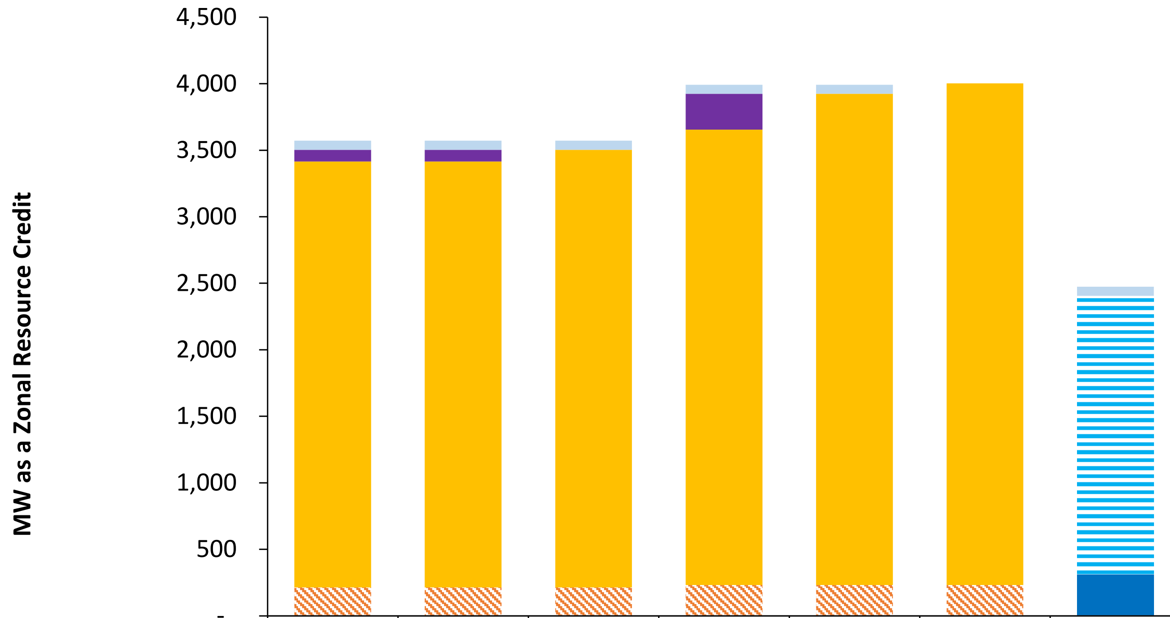
	BAUCE	ETCE	EPCE	BAUAEO	ETAEO	EPAEO	AdvTech
Covert Asset	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	767	767	767	767	767	767	767
New Natural Gas	-	-	-	-	-	-	-
Battery Storage	-	-	-	-	-	-	-
Demand Response	87	87	-	-	-	-	-
Solar (Distribution)	-	-	-	-	-	-	820
Solar (Transmission)	1,219	1,219	1,306	1,382	1,382	1,382	-
Behind-the-meter generation	-	-	-	-	-	-	163
Energy Waste Reduction	216	216	216	150	150	150	-

In anticipation of ensuring capacity sufficiency by 2030, the following key conclusions were drawn, based on the Aurora-selected resource optimizations in the retirement base cases.

- The majority of remaining capacity need was filled by either transmission- or distribution-connected solar, approximately 2,500 additional MW (1,200 ZRC);
- As supported in Exhibit A-9 (STW-6), EWR was included in the portfolio, providing between 150 to 216 ZRC;
- At $85 per kW or less, the first two tranches of demand response were economically-selected in BAU CE and ET CE scenarios. Under MPSC assumptions, no DR was chosen; and
- Given the addition of baseload and dispatchable generation capacity, Aurora abstained from selections of battery storage capacity.

The next year of significant need in the portfolio that results in a step change of capacity shortfall is 2040. As discussed in the testimony of Company witness Blumenstock, the purchased gas units are assumed to cease operations by May 31, 2040. In Figure 5, the same graphical representation of the Aurora-selected resources is included for that year:

Figure 5: Retirement Base Case Aurora-Selected Resources by 2040



	BAUCE	ETCE	EPCE	BAUAEO	ETAEO	EPAEO	AdvTech
Covert Asset	-	-	-	-	-	-	-
CMS Assets	-	-	-	-	-	-	-
New Natural Gas	-	-	-	-	-	-	-
Battery Storage	68	68	68	68	68	-	68
Demand Response	87	87	-	269	-	-	-
Solar (Distribution)	-	-	-	-	-	-	2,095
Solar (Transmission)	3,203	3,203	3,290	3,425	3,693	3,772	-
Behind-the-meter generation	-	-	-	-	-	-	310
Energy Waste Reduction	213	213	213	231	231	231	-

The following key conclusions were drawn from Aurora optimization results by 2040:

- With the cease of operations of the purchased gas unit capacity, additional solar capacity is added, for a total of approximately 7,000 MW (3,500 ZRC) of incremental solar capacity;
- EWR programs continue year-over-year planned amounts, with between 213 and 231 ZRC contributing to filling the shortfall;
- In the first year following the cease of operation of the purchased gas units, storage capacity is added, albeit only about 70 MW; and
- Limited additional DR is selected, as compared with selections from 2030.

Given the pattern of observations in Aurora's resource affinities in the two years of greatest significant need (2030 and 2040), the PCA was developed under retirement base case assumptions and with the following additions of capacity:

- The first two tranches of DR will be included, totaling approximately 90 MW, given that these first two tranches were economically competitive under the Company's view of the most probable scenario, BAU CE, as a least-cost resource, by 2030;
- EWR and CVR programs will be included in the PCA, according to results of the potential study, as supported by economic favorability presented in Exhibit A-9 (STW-6);
- While not economically selected by Aurora, battery storage will be included in the PCA, though not until 2030, with the expectation that battery storage technologies will continue to advance, as they do today, resulting in improvements in economic favorability and operational flexibility, in the future;
- The remainder of capacity shortfall will be served by the gradual addition of solar capacity at no more than 500 MW per year, ensuring sufficiency of capacity to meet the PRMR in each of the targeted years 2030 and 2040. The Company does not dictate whether the solar capacity will be transmission or distribution-connected; instead, the competitive solicitation process ensures the lowest-cost resources are selected at either voltage level;
- The BTMG resource was evaluated to understand the portfolio changes associated with customer adoption of BTMG; but this resource was offered in at no cost, which obviously is not realistic. Due to uncertainty in adoption rates and resource costs, BTMG will not be included in the PCA at this time;
- As mentioned earlier in this direct testimony, the Company has no plans to install new-construction fossil-fueled generating capacity, and no CT capacity was selected, therefore those resources will not be included, either; and
- Wind was selected in so few sensitivities and not at all in the retirement base case sensitivities, so expansion of wind will not be included in this PCA.

Q. Were there any other ways in which Aurora results were used to inform the PCA?

A. Yes. While Aurora's capacity expansion and production cost modules were used to determine the resource selections from an *economic perspective*, Aurora was also utilized as a risk analysis tool, particularly, to perform an analysis to determine the extent to which the PCA and alternate plan would result in the potential for loss of load events. The next section of this testimony discusses this analysis in detail.

Q. The PCA not only meets the PRMR, but includes a significant amount of surplus in many years of the study period. Please explain why this is.

A. As explained above, the design of the PCA was primarily structured on filling large step-change losses of capacity in years 2030 and 2040 under the retirement base case assumption. As discussed in section VIII of this testimony, a glide path gradual addition of capacity was selected for the PCA, as it provides the Company with the flexibility to adjust as market and regulatory constructs change through time. It also allows the Company to pivot its plan, should more efficient or lower-cost resources become available. The gradual addition of capacity avoids large locked-in investments in a single technology resource. This method of capacity expansion, however, tends to "pre-build" for those targeted years (2030 and 2040), which will result in surplus capacity, particularly in years immediately proceeding the targeted years (for example, 2028, 2029, 2038 and 2039 will have the greatest amounts of surplus capacity).

Q. In the targeted years 2030 and 2040, a surplus of approximately 200 ZRC persists. Why does the glide path not solve for a 0 MW surplus in those years?

A. While the theoretical objective – and the solve target within Aurora optimizations – is to solve to meet the PRMR perfectly (i.e. result in a 0 MW shortfall or surplus), in practice, such a plan would pose significant risk. Many of the resources included in the Company's PCA rely on customer engagement – subscription to customer demand-side programs, or reliance on customer behavior to reduce their consumption. Additionally, as discussed in the testimony of Company witness Troyer, the Company's mechanism by which it secures solar capacity is done through annual competitive solicitations. The acquisition of capacity by these avenues carries risk – the risk to acquire an *exact* amount of ZRC, the risk to ensure the new capacity's commercial operation date aligns with MISO requirements to supply capacity by a given planning year, and the risk of developers' schedules and MISO's approvals adhering to the timeline presented in this IRP. Lastly, the PRMR, as well as the values of ZRC provided by portfolio resources are *forecasts*, which, as discussed in Section V of this direct testimony, carrying inherent risk.

These are significant execution risks customers would be exposed to if the Company's plan was to solve to exactly 0 ZRC. Instead, the PCA provides for a reduction to customer risks by planning for no less than 200 ZRC above projected PRMR levels.

SECTION XI: CAPACITY SUFFICIENCY ANALYSIS

Q. Company witness Blumenstock discusses the critical component of electric supply reliability within this IRP. Please discuss what your testimony will cover, with regard to the Company's capacity sufficiency analysis.

A. My testimony will cover the following details regarding the electric supply reliability capacity sufficiency analysis:

- Definition of the Company's capacity sufficiency analysis ("CSA") and how it compares and differs from a loss of load expectation analysis;
- A description of the scope and design of the Company's CSA;
- The evaluation parameters, or input variables, considered, or "shocked" as part of the CSA;
- A description of the particular sensitivities evaluated within the IRP scenario and sensitivities;
- The CSA modeling methodology and assumptions; and
- Results and interpretation of the CSA.

Capacity Sufficiency Analysis and Loss of Load Expectation ("LOLE") Analysis

Q. Can you define what is meant by Capacity Sufficiency Analysis and how it is like or differs from an LOLE analysis?

A. In this IRP, the Company has conducted a CSA to understand the sufficiency of a portfolio of resources to serve projected customer demand. A CSA is similar to an LOLE analysis in that both studies seek to evaluate how a given portfolio of resources performs under a set of simulations in which relevant input variables are exaggerated to understand the likelihood that the resource capacity may be insufficient to serve hourly demand. The studies may differ in a variety of ways. These differences include, but are not limited to: 1) an LOLE study is generally done at the regional transmission organization ("RTO") level, while the CSA was done for the Company's footprint only; 2) the metrics by which an LOLE determines sufficiency may be different than the metrics used by the Company in its CSA; and 3) an LOLE study generally will solve to a North American Electric Reliability Corporation ("NERC") defined target and determine an appropriate planning reserve margin by adding resources to ensure the standard is met, while the CSA identified results through its metric and used the metric to judge the sufficiency of portfolios – that is, additional resources were not added through the CSA analysis, nor is a reserve margin identified as part of the solution.

Q. Please provide a more detailed description of the Company's CSA, including the metric evaluated in the results of the analysis.

A. The goal of the CSA is to consider a pre-determined set of portfolio resources (supply or demand side) against a projected level of demand, identify the set of input variables that pose a risk to capacity sufficiency, and conduct a series of simulations that test the input variables, compared to base levels. By varying the input assumptions, the simulations create extreme conditions under which the portfolio's ability to serve hourly demands is tested. When enough of these simulations are run, one can reasonably assess the probability of capacity insufficiency in every hour of the year.

The metric developed for evaluation in the CSA is based on the ratio of the number of capacity insufficiency *events* divided by the total number of simulations. Within the context of the CSA, **capacity insufficiency** occurs whenever supply or demand-side resources are insufficient to meet demand in a given hour, which can be thought of as the loss of load in that hour. However, a capacity insufficiency **event** is defined as occurring whenever a loss of load hour either follows a non-loss of load hour – or is the first loss of load hour of the year. In this way, consecutive loss of load hours constitute a single loss of load – or capacity insufficiency – *event*. This differs from the standard LOLE metric, as defined in the NERC standard BAL-502-RF-03, which measures the sum of the probabilities for loss of load *for the integrated peak hour* for all days of each planning year analyzed, with no more than 0.1 as the target (0.1 day per year, or 1 day in 10 years).

Evaluation Parameters

Q. What evaluation parameters did the Company include in the CSA simulations?

A. Four evaluation parameters were evaluated within the CSA and are discussed in detail, below.

The first parameter evaluated focused on the availability of thermal generating units as well as Ludington pumped storage facility. Given a base assumption of planned (scheduled) maintenance and random outage rates, a frequency duration outage methodology is employed within Aurora to introduce more randomization – or the unpredictable nature of baseload or fast-responding generation resource availability. One hundred stochastic risk draws were simulated in Aurora, varying the duration and timing of unexpected generator outages. By randomly removing generator capacity from service, the simulations capture the risk that significant capacity resources may not be available when needed, potentially causing a loss of load hour. Information regarding the assumed random outage rate used as the baseline can be found in the direct testimony of Company witness Munie.

The second parameter evaluated is the risk of hourly customer demand changes. Load forecast uncertainty can be one of the greatest risks, with the potential for greatest variances. Company witness Munie discusses the standard deviation of plus and minus 9.1% included in the stochastic risk simulations that were used here, in the CSA, including the basis of the value to represent both weather and economic drivers of load variability. Given an initial seed, a series of risk factors are developed as the scalar multiple to hourly demands across the year, such that the standard deviation of the positive risk factors equals 9.1% and the standard deviation of the negative risk factors equals -9.1%. A risk factor, the scalar value multiplied to hourly demands, can be significantly higher than 9.1% or significantly lower than -9.1%, and the span of scalar multiples creates a range of load forecast simulations to which the specified portfolio can be compared.

The third parameter considered in the CSA is the unpredictability of intermittent resources, specifically, solar and wind generation profiles. As part of the 2018 IRP, the Company indicated plans to rely heavily on solar technology to meet its PRMR and serve hourly customer demands. Furthermore, under compliance with PA 295, Michigan's renewable portfolio standard ("RPS") requires achieving 15% renewable supply by 2021; correspondingly, the Company has added several wind generation resources to its portfolio. Given the significant portion of these intermittent resources within the portfolio, the CSA considers the risk of reliance on these resources as it impacts electric supply reliability. Specifically, the CSA considers a variety of hourly solar and wind generation profiles and randomly creates ten pairings of a solar profile and a wind profile, and then performs the stochastic risk simulations within each of the ten renewable profile pairings. This creates 1,000 iterations (ten renewable profile pairings evaluated under 100 stochastic risk draws) of risk analysis under the first three input variables considered.

The fourth evaluation parameter was the responsiveness of demand-side programs, specifically, demand response. Many optimization portfolios considered within the IRP have varying levels of reliance on DR to meet PRMR, which could result in a degree of risk for meeting peak demand levels – that is, the utility may not have direct control over customer responsiveness, and the greater the amounts of DR included to meet PRMR, the greater the risk of loss of load events. Accordingly, availability of DR was considered in the CSA. Specifically, the CSA evaluated impacts to loss of load potential at three levels: 1) customer interruption was limited to no more than forty hours per year (as consistent with the base case modeling); 2) customer interruption was limited to no more than ten hours per year; and 3) a final case, assuming customer response is very poor – evaluated as an extreme scenario assuming zero hours of demand response. Under each of 0, 10 and 40 hours of DR dispatch, each of the 1,000 risk simulations combined for a total of 3,000 CSA iterations.

Sensitivity Description

Q. Please provide a description of the IRP sensitivities evaluated within the CSA.

A. This testimony discusses two sensitivities evaluated within the CSA – the PCA and the alternate plan. Table 1 provides a summary of the installed capacity, in MW, of the portfolio of resources included in each of the PCA and alternate plan. This summary corresponds to 2032 installed capacity amounts, with further discussion on the selection of 2032 included below.

Table 1: 2032 Installed Capacity Included in CSA

Installed Capacity (MW)	PCA	Alternate Plan
Campbell 3 (CE Share)	0	785
Ludington Pumped Storage (CE Share)	1,170	1,170
Zeeland	853	853
Jackson	547	547
Hydroelectric	91	91
Wind	858	858
Other Renewable	69	69
Solar	4,810	5,414
Battery Storage	61	820
DR	698	840
Purchased Gas	2,153	0

Q. Why was year 2032 selected for the CSA?

A. The selection of 2032 is less an interest on a point in *time* and more an interest in studying a specific *portfolio* of resources. Most electric reliability studies, including LOLE conducted at the RTO level consider "interesting years," or years perhaps in which there is a significant change in the makeup of a portfolio or significant changes to demand, etc. In the case of the CSA, the Company defines an "interesting year" as a year following significant loss of baseload capacity, as well as considerable addition of intermittent resources. Year 2032 fits the bill well in both sensitivities evaluated. By 2032, in both the PCA and the Alternate Plan, Campbell Units 1 and 2 will be retired; Karn Units 1 through 4 will be retired; and the MCV PPA will have expired, removing over 3,000 MW of controllable generation capacity from the Company's portfolio. Additionally, approximately 5,000 MW of solar capacity is expected to be online by 2032 in both sensitivities, marking what certainly would be considered a significant amount of renewable (intermittent) capacity additions.

Q. What are the implications of choosing 2032 for the analyses instead of a year in closer proximity to current?

A. There aren't too many other factors at play in a CSA. This CSA is set up fairly simply, as discussed in greater detail below, as the direct comparison of capacity resources to demand, with little importance of changes to other variables (for example, uncertainty of energy or natural gas prices is not relevant in a CSA). Therefore, the only other variable of significance would be the demand forecast. As supported in the testimony of Company witness Breuring, the forecasted peak demand, as well as annual generation requirements are relatively flat; specifically, both peak demand and total generation requirements grow less than 2% higher than 2021 levels. It can be noted that application of a historically based standard deviation to a future year forecast more than ten years out generates levels of uncertainty that are not as easily managed as perhaps a more near-term evaluation could be. However, since the standard deviation is relatively broad, the Company expects the range of peak load and energy requirements will ensure the CSA is comprehensive in its stressing of demand variables. Given these considerations, the Company did not have great concern moving the CSA forward to 2032; in fact, the advantages to evaluating the dramatic changes to the portfolio far outweigh the loss of precision that may be expected from stepping the analysis so many years into the future.

Modeling Approach and Methodology

Q. What are the critical points of discussion regarding the modeling approach and methodology?

A. Items relevant to discussion regarding the modeling methodology include: 1) the number of iterations; 2) the model topology, including import capability; 3) the operation of battery and pumped storage within the simulations; and 4) the operation of DR within the simulations.

Q. How many iterations were simulated in the CSA and why was that number chosen?

A. Analyses such as the CSA or RTO-wide LOLE generally have a very high number of iterations – in the thousands or even ten thousand iterations. For example, in its 2019 IRP, DTE Company hired the Brattle Group to perform an LOLE study in which 10,000 iterations were simulated. For Consumers Energy's CSA, the design of the DR scenarios (3) and Renewable Profiles (10 pairings) meant there would be some multiplier to 30 sets of studies. The Company could have chosen 100, 200, 300 or any other number of stochastic simulations for Aurora to draw on the 30 scenarios; the selection of 100 draws was a choice to manage statistical validity with run time constraints. Running 3,000 iterations takes approximately a full week in the CSA Aurora model. Therefore, it seemed likely that anything more than a total of 3,000 iterations would be run-time prohibitive.

Q. How is the model topology set up and different from how Consumers Energy normally utilizes the Aurora model?

A. As discussed in Section V, for capacity expansion and production cost modeling runs conducted in this IRP, the Consumers Energy portfolio and demand are modeled within

Zone 7, and with the remainder of MISO modeled in detail, as presented in Exhibit A-8 (STW-5). However, to perform the 3,000 simulations, the model topology was revised to include only Consumers Energy's demand and its portfolio of supply and demand resources, with a single "unit" to represent energy import capacity, or the import capability Consumers Energy assumes in every hour of the study period. In this analysis, and consistent with the import capability assumed in the rest of this IRP, a value of 3,200 MW of import energy capacity was used. This capacity can be thought of as a "Capacity Import Limit ("CIL") *unit*," which was modeled as a resource within the Consumers Energy footprint. The maximum capability of the unit was 3,200 MW, available in every hour, and the price of the resource was assumed to be extremely high – higher than any other resource in the Consumers Energy portfolio[14] – such that the CIL unit would be the resource of last resort within the CSA simulations. The intention is that all Consumers Energy-owned and contracted resources would dispatch first and any remaining demand would be served by the CIL unit. If hourly demand exceeded the sum of the capacity of the CIL unit and all Consumers Energy portfolio resources, a loss of load hour occurs. Additional information regarding the CIL is included in the direct testimony of Company witness Scott and Company witness Thomas P. Clark.

Q. Is the CIL value of 3,200 MW the latest published value, from MISO?

A. No, Company witness Scott discusses that in its most-recently published LOLE report, MISO determined the new CIL as 4,888 MW.

[14] The price of the resource does not matter except to ensure dispatch order is maintained. There was no accounting of costs in the CSA, this is strictly a comparison of resource capacity to demand.

Q. What is a potential implication of the higher import capability?

A. Within the broader IRP, and as a general principle, a higher CIL would result in the potential for lower cost resources to be available to Zone 7. Within the context of the CSA, the higher CIL would generally result in the potential for lower loss of load event occurrence.

Q. Is the CIL unit's capacity of 3,200 MW shared by all entities on Zone 7?

A. In reality, yes, the CIL is shared amongst all entities within Zone 7. However, for purposes of the CSA, it was assumed that Consumers Energy has full access to the 3,200 MW amount in every hour of the study period.

Q. Is it a reasonable assumption that Consumers Energy would utilize all of the CIL?

A. Likely not, in practice. The Company considered pro-rating only a portion of the total CIL capacity to represent the amount Consumers Energy could import. However, in the end, the full 3,200 MW of capacity was assumed, for two primary reasons. First, there are tie-lines within Zone 7, for example, between Consumers Energy and DTE, that provide additional import capability to Consumers Energy, in addition to the CIL. Second, as stated, MISO has indicated a higher level of CIL than the values included in development of this IRP. The value of 3,200 MW should be thought of as a proxy for an estimate of power available to Consumers Energy customers outside of the Company's portfolio of resources.

Q. Please discuss operation of battery storage and pumped storage within the CSA.

A. The Aurora hourly commitment and dispatch of storage resource in the CSA simulations became complicated when the model topology was revised. Specifically, storage resources much charge – either from resources in the Company's portfolio, or from the "market," or the CIL unit, in this case. However, as was explained previously, the CIL unit was priced at extremely high levels, to ensure that Consumers Energy portfolio resources would dispatch before any reliance on outside sources. As a result, it was observed that with such a topology, the cost of charging storage resources became a constraint on the operation of those resources. To resolve this, "charging resources" were created within the CSA, priced at a typical energy price, derived from hourly runs with the model topology as presented in Exhibit A-8 (STW-5). By allowing the storage resources to charge at a price close to a locational marginal price ("LMP"), the economics of storage resources were not disturbed. Discharge of the storage units follows demand needs. With the additional charging resource capacity added (at the MW amounts of the battery and Ludington pumped storage recharge capacities), the system was off-balance and now in excess of supply (since the charging resources are only theoretical). To eliminate the excess supply, the CIL unit capacity is reduced by the total amount of charging resource capacity. For example, consider a battery storage unit with a 100 MW capacity (and corresponding 100 MW recharge capacity). A charging resource would be introduced into the CSA such that the storage unit could charge and discharge according to expected operations. However, this adds 100 MW of excess capability to the system; therefore, the CIL capacity is reduced, in this example, to 3,100 MW, to bring the equation back in balance.

Q. Please discuss dispatch of DR resources in the CSA.

A. DR resources in this IRP are modeled as load control resources, which generally are resources that respond to price, but can respond to adjust demand.

As discussed earlier in this section, the baseline outlook on DR assumes no more than forty hours of interruption per year, with additional scenarios evaluating ten hours or zero hours. Within Aurora, these limitations are handled via a logic that looks ahead, within the simulation, and identifies the highest demand hours of the year (either the 0, 10 or 40 highest demand hours) and schedules DR dispatch economically during those hours. It is noteworthy that even if a loss of load hour occurs, if that hour falls outside the 0, 10 or 40 highest hours of the year, demand response is not able to resolve the loss of load in these simulations.

CSA Results and Interpretation

Q. How are results of the CSA provided?

A. Results of the CSA are presented in three ways. First, a set of examples has been compiled, to show what a loss of load hour looks like, from an hourly supply and demand perspective. Second, a graphical representation of the concentration of loss of load hours per year is presented for both the PCA and the alternate plan. These are referred to as "heat maps," to identify the months and hours of the day that tend to have the most severe occurrence of loss of load. Third, presentation of results is given through the metric for measuring capacity sufficiency, discussed previously in this section. The total number of loss of load events per year is divided by the total number of simulations, such that an average number of loss of load events per year is determined across the 3,000 iterations.

Q. Please provide a detailed example of what a loss of load event "looks like" on an hourly basis, in terms of supply and demand balances.

A. Exhibit A-16 (STW-13) includes five pages, with illustrative instances of loss of load events. These examples do not necessarily correspond to either the PCA results or the alternate plan results; instead, they are simple examples of specific hours of loss of load events observed throughout development of the CSA. However, the portfolio of resources included in Exhibit A-16 (STW-13) correspond to a sensitivity that included high levels of renewable resources and storage resources, similar to the alternate plan.

Starting on page 1, a typical day is shown as a baseline: certain resources, such as solar, storage, Ludington pumped storage and DR, when applicable, are highlighted as column series; the rest of the resources are included in an aggregate, shown as "Remaining Resources." This aggregate would include many of the resources listed in Table 1, above. Two additional series are included in the column chart – "Import" which represents the CIL unit, described earlier in this section, and "Storage Charging," also discussed earlier, representing energy *consumed* to charge the battery or pumped storage resources. This series is colored similarly to the CIL unit because the charging capability is often provided by the CIL unit. Lastly, a line series is included, representing hourly demand. On this first page, conditions are as-expected, with demand sufficiently served in every hour of the day, which happens to be July 19, 2032.

On page 2, the same day is selected, July 19, 2032, however, this graphic corresponds to a stochastic risk iteration that increased load by a factor of 23%. Compared with the graph on page 1, it's clear that demand is higher, which causes resources to dispatch differently than they did on page 1. The exception is solar, which, in this example produced at exactly the same levels as the example from page 1. To meet the increased demand, many of the resources included in "Remaining Resources" are dispatched up, storage resources produce as much power as possible, given their current levels of stored energy, and Imports are elevated; however, in Hour 21, at 9:00 pm on a hot summer day, there is a loss of load hour – an insufficiency of resources to meet the persistently high demands.

Because the potential for loss of load occurs in any hour of the year – not just on hot summer days with high demand – an example was chosen, and shown on page 3, of the potential for loss of load during winter periods, particularly on cloudy days with elevated levels of demand. On page 3, demand on January 7, 2032, was increased by 17% in the stochastic risk simulation and solar outputs were essentially at zero MW in every hour of the day. Storage resources and Remaining Resources responded, Import utilization was maximized, yet hours 7-20 resulted in loss of load.

Page 4 includes two figures, which provide one of the most significant cases included in the exhibit. On page 4, two days are presented, September 7, 2032, and the day following, September 8, 2032. The significance of this set of examples is that this iteration, in which demand was increased by 23%, resulted in consecutive days resulting in loss of load. What's most interesting to notice is the operation of storage resources like batteries and Ludington. The storage resources begin responding to loss of load hours, occurring for the first time on September 7 in Hour 7, steadily increasing their output through Hour 11. However, by Hour 12, the resources are depleted of their storage contents and loss of load continues. In the following hour, the storage resources begin to *charge*, despite the on-going loss of load, when solar output increases and using some of the Import capability; later, the storage discharges in evening hours (starting in Hour 19 at 7:00 pm) when solar output declines. It can be observed that the mid-day charging periods exacerbate the loss of load event. The simulation chose to charge, despite the loss of load, because it identified periods of *more* severe loss of load hours later in the day as well as in the *next day*, shown in the second chart on this page. Similar observations can be made on September 8th – the model choosing to charge storage resources in Hours 1 through 6, despite on-going losses of load, with discharging occurring later in the day when the loss of load is at its deepest. This example illustrates that storage resources may not be the solution to resolve electric reliability concerns, especially on consecutive days of high demand. One of the challenges of these resources is the relatively short duration at which these resources can output capacity, and the relatively shallow depth of energy storage capacity. Further development of longform or long-duration storage resources may provide a solution some day in the future.

The last example, shown on page 5, addresses the role DR may play in reliability simulations. In this example, which occurs on August 4, 2032, with demand increased by 23%, the DR resource indeed responds during the highest demand hours – however, the loss of load event occurs when solar resources fall offline, in Hour 21 at 9:00 pm. While in practice, DR need not be dispatched only during the highest demand hours, this example illustrates the fact that DR programs may be limited in nature, and are unlikely to respond to resolve all loss of load hours.

Exhibit A-17 (STW-14) is a review of the same set of days provided in Exhibit A-16 (STW-13), but corresponding to a portfolio including the addition of controllable generation. As in the prior illustrative examples, the figures in this exhibit do not necessarily correspond to the PCA, but they were based on a portfolio of resources very similar to those presented in Table 1 under the heading “PCA”.

Page 1 of Exhibit A-17 (STW-14) again presents a baseline typical day, July 19, 2032. While similar to page 1 of the prior exhibit, it can be observed that with the addition of approximately 2,000 MW of baseload, reliable generation resources, referred to in the chart as “Purchased Gas,” resource capacity is actually in *excess* of demand in some hours.

The excess capacity in Hours 11 through 17 is available and used to charge storage resources like batteries or Ludington.

On page 2, the same day as the baseline example, but with load increased by a factor of 23% is again presented. In the high renewable portfolio example, a loss of load hour occurred in Hour 21, at 9:00 pm. In this exhibit, we see that the loss of load occurrence persists, which is not a surprise on a summer day with such signficant increases to demand; but the severity of the loss of load went from 603 MW of capacity insufficiency under the high renewable portfolio to 239 MW with the additional gas units added. As will be seen in the remaining examples, out of the five examples of loss of load hours highlighted in Exhibit A-16 (STW-13), only two of the five days discussed have loss of load occurrence under a portfolio that adds controllable baseload generating resources.

On page 3, compared with the loss of load occurring in winter months under the high renewable portfolio example, the controllable generation portfolio has resolved the loss of load hours. In Exhibit A-16 (STW-13), loss of load hours occurred between Hours 7 through 20; in Exhibit A-17 (STW-14), no loss of load hours are experienced, with the baseload generation resources maintaining sufficient supply throughout the day.

Page 4 is a comparison to the most concerning example presented in Exhibit A-16 (STW-13) – the persistence of loss of load hours on consecutive days of high demand, where a total of 44 hours of loss of load occurred over a 48-hour period. Under a portfolio including additional controllable generation resources, page 4 of Exhibit A-17 (STW-14) indicates that all 44 loss of load hours are resolved under the same demand conditions with the addition of 2,000 MW of baseload resources. This is a remarkable improvement in electric supply reliability.

Finally, page 5, the second of the five examples that still result in loss of load hours is presented. As before, even though DR responds during peak demand hours, as solar output declines, a loss of load hour occurs in Hour 21 at 9:00 pm, even with the additional baseload resources. However, as in the first example, while the high renewable portfolio experienced a loss of load of 574 MW on August 4, 2032, the controllable generation portfolio loss of load is only 210 MW.

Q. Please discuss the next presentation of CSA results – the graphical representation of all loss of load hour results.

A. These set of results can be thought of as "heat maps," indicating the concentration or severity of loss of load hours. Exhibit A-18 (STW-15) provides a visual that "locates" the specific hour of the day where loss of load events tend to occur. As this can vary by season, results are presented for each month of the year evaluated. Finally, shading is used to indicate how frequently a loss of load event occurs within each of the 24 hours. The darkest of the shading indicates an hour in a given month that resulted in the most number of loss of load hours, compared to the lightest of shading, which may correspond to only one loss of load hour across the 3,000 simulations. The shading is determined by taking the sum of all loss of load hours occurring within the simulations in the specified hour and month. For example, the darkest shade on page 1 corresponds to 679 total loss of load hours occurring in Hour 6 for all April months across the 3,000 iterations (8,760 hours per simulation).

Page 1 of Exhibit A-18 (STW-15) is the heat map corresponding to the CSA results for the alternate plan. In this high renewable portfolio of resources, we see the occurrence of loss of load hours in many hours of the day in the months of January, March, April, July, August, September, and December.

In contrast, on page 2, results of the CSA from the PCA portfolio of resources is presented, which reflect an obvious reduction in the occurrence of loss of load hours. In fact, only the months of July and November result in any loss of load, and the severity of loss of load is negligible, when compared with results from page 1. In this example, the darkest shading corresponds to Hour 8 in November, in which 18 loss of load hours occurred across all 3,000 simulations (8,760 hours per simulation).

These CSA heat maps demonstrate the compelling support that the PCA, which includes the addition of controllable generation, results in a dramatic improvement in the electric supply reliability concerns associated with high renewable portfolios. The PCA provides a balanced portfolio of controllable generation, pumped storage resources, renewable capacity, energy waste reduction, and demand response.

Q. Please discuss the third and final measure of results of the CSA, the metric discussed earlier in this section.

A. The final result of the CSA is a metric calculated as the total number of loss of load events per year divided by the total number of simulations. This result is presented as a figure directly on the heat maps provided in Exhibit A-18 (STW-15). On page 1, a red circle indicating the CSA result of 0.9 average loss of load events per year for the alternate plan. In comparison to similar analyses conducted by MISO, for example, this exceeds a comparable metric used in LOLE analysis by a factor of 9. Page 2 includes a green circle on the heat map, indicating acceptable levels of loss of load events, a result of 0.01 average loss of load events per year for the PCA.

Q. What conclusions can be drawn from the results of the CSA?

A. The CSA performed as part of this IRP is a robust review of the Company's long-term electric supply reliability sufficiency. Through vigorous statistical analysis, two portfolios have been evaluated and presented in this testimony. In addition to an existing portfolio of natural gas, pumped storage and other renewable sources of capacity, the first portfolio (the alternate plan) maintains a heavy reliance on renewable generation – particularly solar capacity – as well as the addition of DR and battery storage. The results of the electric supply reliability studies show that dependence on so many intermittent sources of generation results in significant periods of time for which the potential loss of load may occur. This conclusion is shown in the density of events presented in the heat map included on page 1 of Exhibit A-18 (STW-15). On the other hand, the second portfolio, the Company's PCA, includes a more balanced source of generation capacity – adding *controllable generation* to the proposed expansion of renewable energy and DR. The results of the study under this portfolio resulted in significant improvements in the long-term reliability sufficiency outlook, a remarkable reduction in the density of loss of load hours, highlighted on page 2 of Exhibit A-18 (STW-15).

SECTION XII: CAPITAL, O&M, AND FUEL COST SUMMARY

Q. What is the final topic you will discuss in your testimony?

A. The final set of data I will discuss and present is presented in support of the testimony sponsored by Company witness Jason R. Coker, for rate impact analysis.

Q. What are the capital and O&M costs associated with the PCA used in the rate impact analysis?

A. The capital and O&M costs associated with the PCA are summarized in Exhibit A-19 (STW-16).

Beginning on page 1, lines 1 through 9 of this exhibit, the cumulative installed capacity additions[15] associated with the Company's PCA are provided for each year 2021 through 2040. Lines 11 through 19 detail the capital expenditures associated with the *incremental* capacity resources added in each year. Lines 21 through 29 detail the cumulative O&M expenses associated with the resource additions.[16] Lines 31 through 35 provide the annual PSCR expenses at varying levels of capacity prices, and corresponding levels of capacity sales revenues associated with the PCA.

The same format of data is provided on page 2 for the Company's Alternate Plan.

Q. What are the capital and O&M costs associated with the required retirement analysis as part of the Settlement Agreement in MPSC Case No. U-20165, the 2018 IRP?

A. The capital and O&M costs supporting the required retirement analyses are summarized in Exhibit A-19 (STW-16) pages 3 through 15. These pages are structured similarly to pages 1 and 2 of this Exhibit, with the exception being lines 31 through 35 from pages 1 and 2. For the retirement sensitivities included on pages 3 through 16, the PSCR expense is provided only on line 31 and corresponds to the PSCR expenses assuming no capacity sales revenues – or in other words, assumes a capacity price corresponding to 0% of CONE. No rate impacts were conducted at varying capacity prices for these sensitivities.

[15] Capacity additions represent incremental MW to existing levels.
[16] As explained in Section VII of this direct testimony, for modeling purposes, all costs associated with incremental DR are assumed to be O&M-related; however, in reality, and presented in this exhibit, some of those costs will likely be allocated as capital investments.

Q. Are there any additional capital and O&M cost outlooks provided in this exhibit?

A. Yes. As discussed in the testimony of Company witness Blumenstock, the Company also considered the accelerated retirement of Karn Units 3&4 by May 31, 2025, instead of the base case assumption of May 31, 2031. This sensitivity is included on page 16 of Exhibit A-19 (STW-16) and follows the same format as pages 3 through 15 of this exhibit discussed above.

Q. What are the fuel cost projections provided in support of this IRP?

A. Projected coal, natural gas, and oil fossil fuel costs for existing owned generating assets, as well as the existing natural gas plants proposed for acquisition in the PCA, are provided in Exhibit A-20 (STW-17). For each of the eight scenarios discussed in Section IV of this direct testimony, a summary of the fuel costs projected has been provided, by scenario, and by portfolio, for each of the following portfolios: (i) Aurora selected (optimal plan); (ii) PCA; and (iii) alternate plan, where applicable. This exhibit contains 20 pages – three portfolios for each of the six Consumers Energy and MPSC scenarios (BAU, ET and EP, for a total of 18), as well as for the AT and Carbon Reduction scenarios. Pages 1 through 3 provide fuel costs associated with the BAU AEO gas scenarios – page 1 corresponds to fuel costs projected in the retirement base case Aurora selected portfolio, page 2 from the PCA, and page 3 from the alternate plan retirement assumptions. Pages 4 through 6 present fuel costs associated with each portfolio under BAU CE gas; pages 7 through 9 for ET AEO gas; pages 10 through 12 for ET CE gas; pages 13 through 15 for EP AEO gas; and pages 16 through 18 for EP CE gas; page 19 corresponds to the retirement base case optimal plan for AT; and page 20, the Carbon Reduction scenario results under retirement base case assumptions. On each page, lines 1 through 5 provide projected costs for coal, lines

6 through 9 and 13 through 27 provide projected costs for natural gas, and lines 10 and 11 provide projected costs for oil.

Q. Does this complete your direct testimony?

A. Yes.

ZONAL RESOURCE CREDITS

Line No.	(a) Electric Generator Name	(b) Resource Type	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
	Owned																					
1	Alcona 1-2	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2	Allegan 1-3	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	Cadillac Solar Garden	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Campbell 1	Coal	248	250	252	252	252	252	252	252	252	252	-	-	-	-	-	-	-	-	-	-
5	Campbell 2	Coal	317	326	336	337	336	335	335	335	335	335	-	-	-	-	-	-	-	-	-	-
6	Campbell 3	Coal	747	743	757	757	757	757	756	756	756	756	756	756	756	756	756	756	756	756	-	-
7	Campbell A	Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Circuit West	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Cooke 1	Reservoir Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	Cooke 2	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
11	Cooke 3	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
12	Crescent Wind	Wind	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
13	Cross Winds Phase 1	Wind	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
14	Cross Winds Phase 2	Wind	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
15	Cross Winds Phase 3	Wind	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
16	Croton 1-4	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
17	Five Channels 1	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
18	Five Channels 2	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
19	Foote 1-3	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
20	Gaylord 1	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gaylord 2	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Gaylord 3	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Gratiot Farms Wind Project	Wind	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
24	GVSU Solar Garden	Solar	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
25	Hardy 1	Reservoir Hydro	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
26	Hardy 2	Reservoir Hydro	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
27	Hardy 3	Reservoir Hydro	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
28	Hodenpyl 1-2	Run of River Hydro	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
29	Jackson Plant	Natural Gas	538	537	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538
30	Karn 1	Coal	196	190	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Karn 2	Coal	195	194	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Karn 3	Natural Gas/Oil	440	437	444	450	448	449	449	450	450	450	-	-	-	-	-	-	-	-	-	-
33	Karn 4	Natural Gas/Oil	327	332	344	335	336	338	340	340	340	340	-	-	-	-	-	-	-	-	-	-
34	Lake Winds Energy Park	Wind	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
35	Loud 1	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
36	Loud 2	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
37	Ludington 1	Pumped Storage	188	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186
38	Ludington 2	Pumped Storage	164	179	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
39	Ludington 3	Pumped Storage	177	186	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184
40	Ludington 4	Pumped Storage	192	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191
41	Ludington 5	Pumped Storage	185	188	190	189	189	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
42	Ludington 6	Pumped Storage	189	188	186	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
43	Mio 1-2	Run of River Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
44	Rogers 1-4	Run of River Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
45	Straits 1	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Tippy 1-3	Run of River Hydro	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
47	Webber 1-2	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
48	WMU Solar Garden	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
49	Zeeland 1A	Natural Gas	157	156	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
50	Zeeland 1B	Natural Gas	153	153	152	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
51	Zeeland 2A	Natural Gas	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
52	Zeeland 2B	Natural Gas	154	153	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
53	Zeeland 2C	Natural Gas	212	210	211	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
	Non-Utility Generators (NUGs)																					
54	River Fork Solar	Solar	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
55	Ada Cogeneration LP	Natural Gas	29	29	29	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Adrian Energy Associates, LLC	Landfill Gas	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
57	Bay Windpower I (Mackinaw)	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Beaverton, City of	Run of River Hydro	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Beebe Renewable Energy	Wind	10	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-
60	Black River Power	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Boyce Hydro Power, LLC (Edenville)	Reservoir Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Boyce Hydro Power, LLC (Sanford)	Reservoir Hydro	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Boyce Hydro Power, LLC (Secord)	Reservoir Hydro	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	Boyce Hydro Power, LLC (Smallwood)	Reservoir Hydro	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cadillac Renewable Energy, LLC	Biomass	34	34	34	34	34	34	34	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Commonwealth Power Company (Irving)	Run of River Hydro	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
67	Commonwealth Power Company (LaBarge)	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-

ZONAL RESOURCE CREDITS

Line No.	(a) Electric Generator Name	(b) Resource Type	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
68	Commonwealth Power Company (Middleville)	Run of River Hydro	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
69	Brook View Dairy	Anaerobic Digester	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-
70	Scenic View Dairy (Fennville)	Anaerobic Digester	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
71	Green Meadow Farms	Anaerobic Digester	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-
72	EARP Solar (Expansion)	Solar	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
73	EARP Solar (Original)	Solar	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Elk Rapids Hydroelectric Power, LLC	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Entergy Nuclear Power Marketing, LLC (Palisades)	Nuclear	772	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Fremont Community Digester, LLC	Anaerobic Digester	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-
77	Gas Recovery 1 (C&C 1)	Landfill Gas	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
78	Gas Recovery 2 (C&C 2)	Landfill Gas	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Genesee Power Station LP	Biomass	26	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-
80	Geronimo Huron Wind, LLC (Apple Blossom)	Wind	17	17	17	17	17	17	17	17	17	17	17	-	-	-	-	-	-	-	-	-
81	Energy Developments (Grand Blanc), LLC	Landfill Gas	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
82	Energy Developments (Ottawa), LLC	Landfill Gas	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
83	Energy Developments (Seymour), LLC	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
84	Energy Developments (Byron Center), LLC	Landfill Gas	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Energy Developments (Pinconning), LLC	Landfill Gas	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Grayling Generating Station LP	Biomass	35	35	35	35	35	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Grenfell Hydro, Inc	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
88	Harvest II Windfarm, LLC	Wind	10	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-
89	Heritage Garden Wind Farm I, LLC (Wind Portion)	Wind	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
90	Heritage Garden Wind Farm I, LLC (Solar Portion)	Solar	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
91	Heritage Stoney Corners Wind Farm I, LLC (Phase 2)	Wind	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
92	Heritage Stoney Corners Wind Farm I, LLC (Phase 3)	Wind	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
93	Hillman Power Company LLC	Biomass	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Kent County	Solid Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Michigan Power LP 1	Natural Gas	73	73	73	73	73	73	73	73	73	-	-	-	-	-	-	-	-	-	-	-
96	Michigan Power LP 2	Natural Gas	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-
97	Michigan Wind 1, LLC (PPA 1)	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Michigan Wind 1, LLC (PPA 2)	Wind	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Michigan Wind 2, LLC	Wind	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-
100	Midland Cogeneration Venture LP	Natural Gas	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	-	-	-	-	-	-	-	-	-	-	-
101	North American Natural Resources (Lennon), Inc	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
102	North American Natural Resources (Rathbun), Inc	Landfill Gas	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-
103	North American Natural Resources (Venice), Inc	Landfill Gas	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	North American Natural Resources (Peoples), Inc	Landfill Gas	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-
105	STS Hydropower Ltd (Ada)	Run of River Hydro	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	STS Hydropower Ltd (Cascade)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	STS Hydropower Ltd (Fallasburg)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
108	STS Hydropower Ltd (Morrow)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
109	TES Filer City Station LP	Coal	58	58	58	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	TES Filer City Repower	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Viking Energy of Lincoln A LP	Biomass	17	17	17	17	17	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Viking Energy of McBain A LP	Biomass	18	18	18	18	18	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	White's Bridge Hydro Company	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
114	WM Renewable Energy (Northern Oaks)	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
115	WM Renewable Energy (Pine Tree Acres)	Landfill Gas	12	12	12	12	12	12	12	12	12	12	-	-	-	-	-	-	-	-	-	-
116	WM Renewable Energy (Venice)	Landfill Gas	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	New Contracts w/ Existing PURPA QFs																					
117	Adrian Energy Associates, LLC	Landfill Gas	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1
118	Bay Windpower I (Mackinaw)	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
119	Beaverton, City of	Run of River Hydro	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
120	Black River Power	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
121	Boyce Hydro Power, LLC (Edenville)	Reservoir Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122	Boyce Hydro Power, LLC (Sanford)	Reservoir Hydro	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
123	Boyce Hydro Power, LLC (Secord)	Reservoir Hydro	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
124	Boyce Hydro Power, LLC (Smallwood)	Reservoir Hydro	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
125	Commonwealth Power Company (Irving)	Run of River Hydro	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
126	Commonwealth Power Company (LaBarge)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
127	Commonwealth Power Company (Middleville)	Run of River Hydro	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
128	Brook View Dairy	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1
129	Scenic View Dairy (Fennville)	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0
130	Green Meadow Farms	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1
131	EARP Solar (Expansion)	Solar	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2
132	EARP Solar (Original)	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
133	Elk Rapids Hydroelectric Power, LLC	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
134	Fremont Community Digester, LLC	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2
135	Gas Recovery 1 (C&C 1)	Landfill Gas	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

Witness: STWalz
Date: June 2021

ZONAL RESOURCE CREDITS

Line No.	(a) Electric Generator Name	(b) Resource Type	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
136	Gas Recovery 2 (C&C 2)	Landfill Gas	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
137	Energy Developments (Grand Blanc), LLC	Landfill Gas	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2
138	Energy Developments (Ottawa), LLC	Landfill Gas	-	-	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3
139	Energy Developments (Seymour), LLC	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
140	Energy Developments (Byron Center), LLC	Landfill Gas	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
141	Energy Developments (Pinconning), LLC	Landfill Gas	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2
142	Grenfell Hydro, Inc	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
143	Hillman Power Company LLC	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144	Kent County	Solid Waste	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
145	North American Natural Resources (Lennon), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
146	North American Natural Resources (Rathbun), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
147	North American Natural Resources (Venice), Inc	Landfill Gas	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
148	North American Natural Resources (Peoples), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3
149	STS Hydropower Ltd (Ada)	Run of River Hydro	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
150	STS Hydropower Ltd (Cascade)	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
151	STS Hydropower Ltd (Fallasburg)	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
152	STS Hydropower Ltd (Morrow)	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
153	Viking Energy of Lincoln A LP	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
154	Viking Energy of McBain A LP	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
155	White's Bridge Hydro Company	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
156	WM Renewable Energy (Northern Oaks)	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
157	WM Renewable Energy (Pine Tree Acres)	Landfill Gas	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12	12	12	12	12	12
158	WM Renewable Energy (Venice)	Landfill Gas	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	New Contracts w/ Solar PURPA QFs																					
159	Cement City	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
160	Letts Creek	Solar	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
161	Pullman	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
162	Thorn Lake	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
163	Good Fruit Storage LLC	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
164	Workman Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
165	NextSun Energy LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
166	Morey Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
167	Lake City Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
168	Hazel Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
169	Hendershot Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
170	Jack Francis Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
171	May Shannon Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
172	13 Mile Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
173	Angola Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
174	Captain Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
175	Coldwater Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
176	Geddes 2 Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
177	Interchange Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
178	Bullhead Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
179	Geddes 1 Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
180	Stoneheart Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
181	Macbeth Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
182	Woodley Solar	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
183	Bingham Solar, LLC	Solar	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
184	Temperance Solar, LLC	Solar	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

ZONAL RESOURCE CREDITS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
185	Albion North Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
186	Allegheny Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
187	Aluminum Solar	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
188	Bamboo Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
189	Beaverton Solar	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
190	Burns Park Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
191	Byrne Solar	Solar	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
192	Cloudbreak Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
193	Congo Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
194	Hogan Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
195	Johnsfield Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
196	Lightfoot Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
197	Lyons Road Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
198	Rosco Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
199	Shipsterns Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
200	Surbrook Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
201	Blue Elk Solar VII	Solar	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
202	Aurthur Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
203	Golden Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
204	Robert Swift Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
205	Swede Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
206	Topanga Solar	Solar	-	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
207	Wilford Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
208	TART Solar, LLC	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
209	Blue Elk Solar I	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
210	Blue Elk Solar III	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
211	Blue Elk Solar IV	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
212	Greenstone Solar, LLC	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
213	Midcontinent Solar, LLC	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
214	Durban Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
215	Esmarelda Solar	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
216	Shady Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Expansion Plans																					
217	2018 IRP Solar	Solar	-	150	300	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
218	Heartland Wind Park	Wind	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
219	Other Bilateral ZRC Purchases	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)
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Witness: STWalz
Date: June 2021

PROJECTED GENERATION (GWH)

Line No.	(a) Electric Generator Name	(b) Resource Type	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
	Owned																					
1	Heartland Wind Park	Wind	-	-	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724
2	5 Channels 1	Hydro	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217
3	Alcona 12	Hydro	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048
4	Allegan 13	Hydro	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053
5	Campbell 1	Coal	1,744,446	1,738,865	1,731,398	1,606,921	1,696,638	1,698,383	1,696,004	1,558,474	1,680,083	1,667,054	735,533	-	-	-	-	-	-	-	-	-
6	Campbell 2	Coal	1,504,879	1,813,078	1,816,000	1,673,253	1,770,472	1,760,411	1,756,811	1,759,361	1,738,726	1,722,632	766,152	-	-	-	-	-	-	-	-	-
7	Campbell 3	Coal	5,984,843	5,983,623	5,995,363	4,922,880	5,938,623	5,974,511	6,013,250	6,024,144	6,005,264	6,022,408	6,017,665	6,038,302	6,024,375	4,903,905	6,016,002	5,978,791	5,896,189	5,766,261	6,219,881	-
8	CE Community Solar Gardens	Solar	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961
9	CE Existing DR	DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Cooke 1	Hydro	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283
11	Crescent Wind	Wind	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708
12	Crosswinds phase 1	Wind	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881
13	Crosswinds phase 2	Wind	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821
14	Crosswinds phase 3	Wind	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585
15	Croton 14	Hydro	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960
16	EARP AD	Other	6,887	6,887	6,887	6,907	6,887	6,887	5,357	3,837	3,826	3,826	3,826	3,837	3,826	3,826	3,826	-	-	-	-	-
17	EARP Solar	Solar	2,207	2,196	391	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	EARP Solar Expansion	Solar	5,114	5,104	5,082	5,099	5,082	5,082	4,986	4,553	1,869	-	-	-	-	-	-	-	-	-	-	-
19	Foote 13	Hydro	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261
20	Gratiot Wind Farm	Wind	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312
21	Hardy 1	Hydro	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565
22	Hodenpyl 12	Hydro	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453
23	Jackson	Natural Gas	2,700,001	2,700,001	2,700,001	2,700,002	2,700,001	2,700,002	2,700,002	2,700,002	2,613,051	2,607,538	2,539,448	2,352,235	2,270,174	2,110,572	2,278,457	2,105,920	2,014,884	2,044,015	1,965,709	1,929,174
24	Karn 1	Coal	1,331,674	1,316,454	588,833	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Karn 2	Coal	1,417,337	1,402,454	634,798	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Karn 3	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Karn 3_Oil	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Karn 4	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Lake Winds Energy Park	Wind	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617
30	Loud 1	Hydro	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223
31	Ludington 1	Storage	(22,195)	(24,509)	(28,294)	(27,851)	(26,681)	(33,363)	(34,161)	(30,724)	(31,228)	(34,902)	(30,088)	(35,681)	(35,852)	(31,108)	(23,270)	(39,477)	(41,410)	(48,194)	(45,167)	(39,731)
32	Ludington 2	Storage	(24,388)	(30,721)	(32,057)	(27,473)	(34,261)	(38,232)	(35,562)	(36,268)	(35,645)	(27,861)	(20,688)	(39,700)	(40,474)	(41,802)	(40,622)	(44,110)	(46,842)	(55,736)	(51,175)	(48,816)
33	Ludington 3	Storage	(18,170)	(36,106)	(39,100)	(36,627)	(40,617)	(45,864)	(45,234)	(42,728)	(42,224)	(42,663)	(39,118)	(44,476)	(45,834)	(45,068)	(45,812)	(54,264)	(43,604)	(24,313)	(61,090)	(56,678)
34	Ludington 4	Storage	(27,775)	(35,815)	(39,564)	(36,310)	(41,766)	(46,002)	(40,862)	(45,182)	(43,073)	(38,570)	(33,675)	(24,103)	(47,110)	(50,570)	(48,303)	(52,416)	(59,173)	(62,148)	(60,428)	(64,340)
35	Ludington 5	Storage	(22,570)	(29,034)	(28,981)	(29,774)	(31,604)	(31,750)	(34,132)	(33,527)	(28,519)	(35,673)	(33,593)	(28,629)	(22,095)	(39,330)	(35,401)	(40,356)	(44,903)	(46,981)	(48,869)	(43,927)
36	Ludington 6	Storage	(25,446)	(32,355)	(31,922)	(33,391)	(35,950)	(36,704)	(39,322)	(38,083)	(34,303)	(38,293)	(37,234)	(36,761)	(34,129)	(25,300)	(40,585)	(48,823)	(50,743)	(53,999)	(57,479)	(50,296)
37	Mio 1-2	Hydro	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528
38	Rogers 14	Hydro	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188
39	Tippy 13	Hydro	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165
40	Webber 12	Hydro	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897
41	Zeeland 1A	Natural Gas	152,069	153,581	338,477	98,518	177,945	96,942	95,338	169,634	-	-	-	24,161	23,405	-	-	-	-	6,097	21,930	4,273
42	Zeeland 1B	Natural Gas	152,133	152,631	337,269	98,144	178,571	96,339	94,994	171,535	-	-	-	24,016	23,519	-	-	-	-	6,732	21,804	4,273
43	Zeeland CC	Natural Gas	4,240,750	4,370,452	4,314,402	4,327,650	4,291,931	4,174,720	3,474,591	3,890,197	3,705,296	3,421,266	3,842,285	3,901,803	3,889,198	3,708,800	3,350,062	3,826,364	3,858,110	2,281,508	2,344,471	2,815,706
	Non-Utility Generators (NUGs)																					
44	TES Filer City Station LP	Coal	489,544	489,544	489,544	490,885	242,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Beaverton City of	Hydro	2,369	2,369	2,369	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Boyce Hydro Power, LLC	Hydro	34,150	14,128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Commonwealth Power Company (Irving)	Hydro	1,503	1,503	1,503	1,507	1,503	1,503	1,503	1,507	1,503	1,000	-	-	-	-	-	-	-	-	-	-
48	Commonwealth Power Company (LaBarge)	Hydro	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	1,720	-
49	Commonwealth Power Company (Middleville)	Hydro	825	825	825	828	825	825	825	828	825	825	-	-	-	-	-	-	-	-	-	-
50	Grenfell Hydro, Inc	Hydro	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	865	-
51	STS Hydropower Ltd (Morrow)	Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	STS HydroPower Ltd-Ada Dam	Hydro	5,643	5,643	2,334	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ada Cogeneration LP	Natural Gas	146,548	147,263	148,168	151,069	150,936	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Michigan Power LP 1	Natural Gas	1,012,831	1,012,831	1,012,831	1,015,606	1,012,831	1,012,831	1,012,831	1,015,606	1,012,831	843,564	-	-	-	-	-	-	-	-	-	-
55	Midland Cogeneration Venture LP	Natural Gas	6,724,545	6,296,022	6,912,422	7,468,130	7,209,650	5,092,091	4,344,736	3,415,274	3,055,041	1,052,768	-	-	-	-	-	-	-	-	-	-
56	Entergy Nuclear Power Marketing, LLC (Palisades)	Nuclear	6,871,815	2,885,902	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	Adrian Energy Associates, LLC	Other	17,279	17,279	17,279	17,326	17,279	17,279	17,279	17,326	17,069	-	-	-	-	-	-	-	-	-	-	-
58	C&C 1	Other	13,182	13,182	13,182	13,218	13,182	13,182	13,182	13,218	13,182	2,131	-	-	-	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

Witness: STWalz
Date: June 2021

PROJECTED GENERATION (GWH)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
59	C&C 2	Other	17,375	17,375	17,375	17,423	17,375	17,375	2,809	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Cadillac Renewable Energy, LLC	Other	116,248	116,248	116,248	116,802	116,324	116,324	116,270	68,000	-	-	-	-	-	-	-	-	-	-	-	-
61	Fremont Community Digester, LLC	Other	13,673	13,673	13,673	13,682	13,673	13,673	13,673	13,682	13,673	13,673	13,673	11,108	-	-	-	-	-	-	-	-
62	Genesee Power Station LP	Other	89,363	89,363	89,363	89,608	89,363	89,363	89,363	89,689	89,441	88,514	-	-	-	-	-	-	-	-	-	-
63	Granger Electric Company (Grand Blanc)	Other	25,295	25,295	25,295	25,365	25,295	25,295	25,295	25,365	14,692	-	-	-	-	-	-	-	-	-	-	-
64	Granger Electric Company (Ottawa)	Other	31,290	31,290	31,290	31,376	31,290	31,290	31,290	31,376	15,516	-	-	-	-	-	-	-	-	-	-	-
65	Granger Electric Company (Seymour)	Other	6,280	6,280	6,280	6,297	6,280	6,280	6,280	6,297	6,280	5,747	-	-	-	-	-	-	-	-	-	-
66	Granger Electric of Byron Center	Other	27,038	27,038	27,038	27,112	27,038	7,619	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Granger Electric of Pinconning	Other	19,581	19,581	19,581	19,635	19,581	19,581	19,581	1,663	-	-	-	-	-	-	-	-	-	-	-	-
68	Grayling Generating Station LP	Other	84,066	83,628	82,860	84,039	83,267	83,507	83,387	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Hillman Power Company LLC	Other	153,044	63,314	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Kent County	Other	101,204	13,032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	North American Natural Resources (Rathbun)	Other	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	3,728	-
72	North American Natural Resources (Venice)	Other	17,582	17,582	17,582	17,630	17,582	2,071	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	North American Natural Resources Lennon	Other	12,276	12,276	12,276	12,312	12,276	12,276	12,276	12,312	12,276	12,276	-	-	-	-	-	-	-	-	-	-
74	North American Natural Resources, Inc (Peoples)	Other	18,260	18,260	18,260	18,310	18,260	18,260	18,260	18,310	18,260	12,371	-	-	-	-	-	-	-	-	-	-
75	PURPA Aggregate 1	Other	23,660	24,643	27,950	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362
76	PURPA Aggregate 4	Other	4,129	94,981	115,758	118,524	118,259	146,328	174,672	200,198	229,360	299,226	344,555	424,202	454,448	454,448	454,448	458,806	461,353	461,353	471,867	480,193
77	Viking Energy of Lincoln A LP	Other	144,135	144,135	144,135	144,530	144,135	144,135	59,629	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Viking Energy of McBain A LP	Other	142,401	142,401	142,401	142,791	142,401	142,401	58,911	-	-	-	-	-	-	-	-	-	-	-	-	-
79	WM Renewable Energy (Venice)	Other	11,792	11,792	11,792	11,824	11,792	11,792	3,877	-	-	-	-	-	-	-	-	-	-	-	-	-
80	WM Renewable Energy Northern Oaks	Other	11,770	11,770	11,770	11,801	11,770	11,770	11,770	11,801	11,770	10,429	-	-	-	-	-	-	-	-	-	-
81	WM Renewable Energy Pine Tree Acres	Other	96,221	96,221	96,221	96,527	96,221	96,221	96,221	96,527	96,221	96,221	96,221	45,283	-	-	-	-	-	-	-	-
82	13 Mile Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
83	Albion North Solar	Solar	3,970	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
84	Allegheny Solar	Solar	4,248	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054
85	Aluminum Solar	Solar	4,873	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984
86	Angola Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
87	Aurthur Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046
88	Bamboo Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
89	Beaverton Solar	Solar	-	17,127	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
90	Bingham Solar, LLC	Solar	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
91	Blue Elk Solar I	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
92	Blue Elk Solar III	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
93	Blue Elk Solar IV	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
94	Blue Elk Solar VII	Solar	-	-	20,946	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651
95	Bullhead Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
96	Burns Park Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
97	Byrne Solar	Solar	4,282	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240
98	Captain Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
99	Cement City	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
100	Cloudbreak Solar	Solar	7,940	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
101	Coldwater Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
102	Congo Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
103	Durban Solar	Solar	-	20,435	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
104	Esmarelda Solar	Solar	1,454	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984
105	Geddes 1 Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
106	Geddes 2 Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
107	Golden Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

Witness: STWalz
Date: June 2021

PROJECTED GENERATION (GWH)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
108	Good Fruit Storage LLC	Solar	449	449	449	450	449	449	449	450	449	449	449	450	449	449	449	450	449	449	449	450
109	Greenstone Solar, LLC	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
110	Hazel Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
111	Hendershot Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
112	Heritage Garden Wind Farm I LLC Solar portion	Solar	968	968	968	970	968	968	968	970	968	968	968	824	-	-	-	-	-	-	-	-
113	Hogan Solar	Solar	7,309	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
114	Interchange Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
115	Jack Francis Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
116	Johnsfield Solar	Solar	6,091	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
117	Lake City Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
118	Letts Creek	Solar	-	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720
119	Lightfoot Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
120	Lyons Road Solar	Solar	12,182	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
121	Macbeth Solar	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
122	May Shannon Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
123	Midcontinent Solar, LLC	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
124	Morey Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
125	NextSun Energy LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
126	Pullman	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
127	Robert Swift Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046
128	Rosco Solar	Solar	6,091	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
129	RPS Solar 2021	Solar	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682
130	Shady Solar	Solar	-	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
131	Shipsterns Solar	Solar	-	28,259	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
132	Stoneheart Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
133	Surbrook Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
134	Swede Solar	Solar	2,180	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
135	TART Solar, LLC	Solar	9,588	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108
136	Temperance Solar, LLC	Solar	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
137	Thorn Lake	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
138	Topanga Solar	Solar	11,910	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440
139	Wilford Solar	Solar	12,182	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
140	Woodley Solar	Solar	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798
141	Workman Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
142	Apple Blossom	Wind	284,698	284,698	284,698	285,616	284,698	284,698	284,698	285,616	284,698	284,698	284,698	285,616	133,678	-	-	-	-	-	-	-
143	Bay Windpower I (Mackinaw)	Wind	982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144	Beebe Renewable Energy	Wind	186,713	186,713	186,713	187,490	186,713	186,713	186,713	187,490	186,713	186,713	186,713	107,232	-	-	-	-	-	-	-	-
145	Harvest II Windfarm LLC	Wind	174,038	174,038	174,038	174,736	174,038	174,038	174,038	174,736	174,038	174,038	174,038	98,706	-	-	-	-	-	-	-	-
146	Heritage Garden Wind Farm I LLC Wind portion	Wind	55,321	55,321	55,321	55,495	55,321	55,321	55,321	55,495	55,321	55,321	55,321	37,753	-	-	-	-	-	-	-	-
147	Heritage Stoney Corners Wind Farm I LLC Phase 2	Wind	30,908	30,908	30,908	31,015	30,908	30,908	30,908	31,015	30,908	30,908	15,415	-	-	-	-	-	-	-	-	-
148	Heritage Stoney Corners Wind Farm I LLC Phase 3	Wind	20,884	20,884	20,884	20,956	20,884	20,884	20,884	20,956	20,884	20,884	10,275	-	-	-	-	-	-	-	-	-
149	Michigan Wind 1, LLC	Wind	28,288	28,288	28,288	28,365	28,288	28,288	28,288	28,365	-	-	-	-	-	-	-	-	-	-	-	-
150	Michigan Wind 2 LLC	Wind	260,226	260,226	260,226	261,348	260,226	260,226	260,226	261,348	260,226	260,226	152,991	-	-	-	-	-	-	-	-	-
151	PCA_CE Solar_2024_500MW	Solar	-	-	-	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008
152	PCA_CE Solar_2022_300MW	Solar	-	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405
153	PCA_CE Solar_2023_300MW	Solar	-	-	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed September 5, 2025

Exhibit 20

King Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.
______________________________________/

Case No. U-21090

Volume 7

PUBLIC RECORD

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
ANNE M. UITVLUGT, ESQ.
IAN F. BURGESS, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

DIRECT TESTIMONY OF THOMAS KING JR

ON BEHALF OF

WOLVERINE POWER SUPPLY COOPERATIVE, INC.

Direct Testimony of Thomas King Jr
On Behalf of
Wolverine Power Supple Cooperative, Inc.

Q. Please state your name and business address.

A. My name is Thomas King Jr. My business address is 10125 West Watergate Rd, Cadillac, MI 49601.

Q. By whom are you employed and what is your position with that employer?

A. I am the Director of Regulation and Policy for Wolverine Power Supply Cooperative, Inc. ("Wolverine").

Q. Please summarize your academic background.

A. I graduated *cum laude* with a Bachelor of Science degree in Electrical Engineering in 2008 from Michigan Technological University. In 2012, I earned my Professional Engineer license for the State of Michigan.

Q. Please summarize your relevant employment and professional experience.

A. From May 2008 until May 2013, I was employed by Wolverine as an Electrical Engineer. My responsibilities as Electrical Engineer involved all facets of Wolverine's transmission planning activities. These activities included: providing power flow analysis support for Wolverine's Energy Control Center ("ECC"), performing the power flow analysis for Wolverine's planning studies, and representing Wolverine for Reliability*First* Corporation ("RF") and Midcontinent Independent System Operator, Inc. ("MISO") studies and committees. In May 2013, I was promoted to my current position as Director of Regulation and Policy. In this position, I am responsible for coordinating Wolverine's regulatory affairs at the federal level with the Federal Energy Regulatory Commission ("FERC"), at the state level with the Michigan Public Service Commission ("MPSC" or "Commission") and at the regional transmission organization ("RTO") level with MISO. I also remain responsible for the transmission planning function and serve as the primary contact with transmission, generation, and distribution partners (ITC, Consumers, etc.) to ensure quality planning and preparation.

Q. Have you previously filed testimony with the MPSC?

A. Yes, I previously filed testimony before the MPSC, including Case Nos. U-17742, U-18254, and U-20497.

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

A. The purpose of my testimony is to address concerns arising from Consumers Energy Company's ("Consumers Energy") proposed early retirement of Campbell Unit No. 3 ("Campbell 3") and associated retirement costs.

In particular, my testimony will describe the history of Wolverine's role as a Joint Owner of Campbell 3, rights and obligations arising from the Campbell Unit No. 3 Ownership and Operating Agreement Between Consumers Power Company and Northern Michigan Electric Cooperative, Inc. and Wolverine Electric Cooperative, Inc. dated August 15, 1980 ("Campbell 3 Agreement"), and the proposed early retirement of Campbell 3 and associated retirement costs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the below-referenced Exhibits as part of my Direct Testimony:

- **Exhibit WPSC-1:** Campbell Unit No. 3 Ownership and Operating Agreement Between Consumers Power Company and Northern Michigan Electric Cooperative, Inc. and Wolverine Electric Cooperative, Inc. dated August 15, 1980.
- **Exhibit WPSC-2:** Consumers Energy Response to U21090-ST-CE-017

Campbell Unit No. 3 Ownership and Operating Agreement

Q. Provide an overview of the Campbell Unit No. 3 Ownership and Operating Agreement Between Consumers Power Company and Northern Michigan Electric Cooperative, Inc. and Wolverine Electric Cooperative, Inc. dated August 15, 1980.

A. On August 15, 1980, Wolverine entered into the Campbell Unit No. 3 Agreement with Consumers Energy to memorialize Wolverine's Joint Ownership of Campbell Unit No. 3 shortly before the Campbell Unit No. 3 was placed into commercial operation on September 17, 1980. The Campbell 3 Agreement established the contracting parties' respective ownership interests in the property included in Campbell 3 and the respective rights and obligations of the contracting parties with respect to the design, procurement, construction, operation and maintenance, capital improvements, and retirement matters regarding Campbell 3.

Consumers Energy currently owns approximately 93% of Campbell 3. Wolverine and the Michigan Public Power Agency own the remaining 7%. Wolverine's joint ownership is subject to the terms and conditions set forth in the Campbell 3 Agreement.

Q. Generally, what rights and obligations arise from the Campbell 3 Agreement as applied to Wolverine?

A. The Campbell 3 Agreement establishes Joint Ownership rights and obligations between the contracting parties, including, but not limited to, matters involving payment, cooperation, and consultation related to the operations and maintenance of Campbell 3, Campbell 3 capital improvements, and retirement.

Q. Explain Wolverine's payment obligations under the Campbell 3 Agreement.

A. Article 7 of the Campbell 3 Agreement established Wolverine's obligation to pay its share of Campbell 3 operating costs, capital improvements; insurance costs; liability payments, costs expenses or obligations; taxes other than income taxes and those taxes included in the operating costs of Campbell 3; and retirement costs.

Q. Have retirement costs been included in Wolverine's monthly payments to Consumers Energy?

A. Yes, over the duration of the Campbell 3 Agreement, retirement costs (a/k/a decommissioning costs) have been included in Wolverine's monthly payments to Consumers Energy.

Article 20.2 of the Campbell 3 Agreement defines retirement costs as all costs less salvage credits, if any, associated with the retirement of Campbell 3, including, without limitation:

dismantling, demolishing and removal of equipment, facilities and structures; security; maintenance; and disposing of debris, shall be shared by the contracting parties in proportion to their respective percentage ownership interests in Campbell 3. Payments made for retirement costs have been included in Wolverine's monthly payments to Consumers Energy made under Article 7.3. Such payments included funds for retirement costs over the life of the Campbell 3 Agreement – more than 40 years.

Q. Does Consumers Energy have an obligation to cooperate with Wolverine as a Joint Owner of Campbell Unit No. 3?

A. Yes, Article 9.1 of the Campbell 3 Agreement requires the contracting parties to: "cooperate with each other in all activities relating to Campbell 3, including, without limitation, the filing of applications for authorizations, permits or licenses and the execution of such other documents as may be reasonably necessary to carry out the provisions of this Agreement." Article 18 of the Campbell 3 Agreement also requires consultation "in connection with any major matter arising under this Agreement" and describes "major retirement matters" as items that require discussion.

Q. Does Consumers Energy have an obligation to consult with Wolverine on matters including retirement?

Yes, Article 18 of the Campbell 3 Agreement obligates Consumers Energy to consult with Wolverine (as a member of the Administrative Committee) regarding "any major matter" arising from the Campbell 3 Agreement. This obligation includes discussing and seeking timely mutual agreement on major matters arising under the Campbell 3 Agreement, expressly including operation and maintenance, capital improvements, and "major retirement matters."

Q. Did Consumers Energy cooperate or consult with the Administrative Committee, or otherwise with Wolverine, prior to publicly announcing the proposed early retirement of Campbell 3?

A. No. Consumers Energy did not cooperate or consult with the Administrative Committee or otherwise with Wolverine on its proposed early retirement of Campbell 3, as required under the Campbell 3 Agreement.

Q. Did Consumers Energy seek timely mutual agreement regarding major retirement matters through the Administrative Committee and/or senior representatives under Articles 16 and 18 of the Campbell 3 Agreement?

A. No. Consumers Energy did not seek agreement to the proposed early retirement of Campbell 3.

Q. When did Consumers Energy inform Wolverine of the proposed early retirement of Campbell 3 and how was that information communicated?

A. On June 23, 2021, Consumers Energy publicly announced an intent to pursue the early retirement of Campbell 3. Approximately 30 minutes before the public announcement, a virtual meeting was held with certain Wolverine representatives (not a meeting of the Administrative Committee) to verbally notify Wolverine of the impending public announcement. Besides that call, no discussions were held between the contracting parties' senior representatives prior to Consumers Energy's public announcement.

Consumers Energy's Proposed Early Retirement of Campbell 3

Q. What is the current status of Campbell 3's book value?

A. Campbell 3 remains used and useful with a remaining net book value estimated to be $924 million at the beginning of 2023. Exhibit A-32. Consumers Energy's proposed early retirement will result in the closure of Campbell 3 at least 15 years before the end of its current design life. *See* Richard Blumenstock Direct Testimony, p. 54. Nevertheless, Consumers Energy seeks to recover the $924 million in remaining net book value of Campbell 3 through regulatory asset treatment. This is independent of Wolverine's members' remaining book value, which Wolverine planned to fully depreciate over the remaining, planned, and useful life of Campbell 3.

Q. Are there issues that require cooperation and consultation prior to any retirement of Campbell 3?

A. Yes. Wolverine has serious concerns about Campbell 3's proposed early retirement, and believe a number of issues should be considered -- and appropriate solutions found – prior to any retirement. Those issues include but are not limited to:

- Potential negative impact on electric reliability in Michigan's lower peninsula;
- The ability of owners other than Consumers Energy to secure cost-effective replacement energy and capacity that does not require their ratepayers to essentially pay twice and in a time frame that allows sufficient lead time for replacement;
- The closure's financial and accounting impact, including the determination of retirement costs netted against payments already received for that purpose;
- Appropriateness of recovery of costs for currently proposed investments in Campbell 3 (for instance those proposed in U-20963) from other owners; and
- Appropriateness of decommissioning activities and costs to ensure such decisions are cost-effective and environmentally protective, to prevent liability for other owners.

Consumers Energy's Projected Decommissioning and Ash Disposal Costs for Campbell 3

Q. What is the total amount of projected decommissioning costs and ash disposal costs that Consumers Energy claims will result from the proposed early retirement of Campbell 3?

A. As reflected in Exhibit A-33 (KJW-2), Consumers Energy projects decommissioning costs of \$50.9 million and ash disposal costs of \$26.1 million for Campbell 3, totaling \$77.0 million. Consumers Energy is requesting approval to recover the decommissioning costs of Campbell 3 through regulatory asset treatment once actually incurred, with a full return from its customers. See Exhibit WPSC-2.

Q. Has Wolverine been contributing to Campbell 3 retirement costs under the Campbell 3 Agreement?

A. Yes, for the life of the Campbell 3 Agreement, Wolverine has been making monthly payments that include retirement costs (a/k/a decommissioning costs) associated with fixed assets. Article 20.2 of the Campbell 3 Agreement defines "retirement costs" as all costs less salvage credits, if any, associated with the retirement of Campbell 3, including, without limitation: dismantling, demolishing and removal of equipment, facilities and structures; security; maintenance; and disposing of debris. These costs shall be shared by the contracting parties in proportion to their respective percentage ownership interests in Campbell 3. Payments made for retirement costs have been included in Wolverine's monthly payments under Article 7.3 of the Campbell 3 Agreement, in proportion to Wolverine's respective percentage of ownership interest.

Q. Has Consumers Energy provided an accounting of decommissioning costs already collected and placed in reserve for Campbell 3?

A. No. As reflected in Exhibit WPSC-2, which is a Consumers Energy discovery response to U21090-SA-CE-017, Consumers Energy confirmed that it is unable to isolate decommissioning dollars that Consumers has included in its depreciation reserve. While a discovery request is pending, it does not appear that Consumers Energy is able to discern payments attributable to retirement/decommissioning cost payments made under the Campbell 3 Agreement since 1980.

Q. Has Consumers Energy provided an accounting of decommissioning costs not yet collected for Campbell 3?

A. No. As further reflected in Exhibit WPSC-2, Consumers Energy acknowledged that it is unable to isolate or define decommissioning dollars yet to be collected for Campbell 3.

Q. **In addition to meeting the burden of proof in Case No. U-21090, does Consumers Energy have any other obligation to provide Wolverine with information and documentation regarding Wolverine's payments attributable to retirements costs made under the Campbell 3 Agreement?**

A. Yes. Article 5.5 of the Campbell 3 Agreement requires Consumers Energy to provide additional information or reports concerning Campbell 3, when requested by Wolverine. The Campbell 3 Agreement also sets forth detailed scheduling and invoicing processes to ensure the accurate tracking of such information. Despite these contractual provisions and requests made thereunder, Consumers Energy appears unable to provide information or reports confirming the amount Wolverine has paid to-date in retirement costs for Campbell 3.

Q. Does Wolverine hold concerns about Consumers Energy's tracking and identification of decommissioning costs at Campbell 3?

A. Yes. Wolverine is concerned that Consumers Energy may seek duplicative and unjust retirement costs from Wolverine or other customers arising from the proposed early retirement of Campbell 3, unless Consumers Energy is able to identify additional information allowing it to track and identify Wolverine's significant payments attributable to such retirement costs made under the Campbell 3 Agreement since 1980. Because of Wolverine's significant retirement cost payments made for more than 40 years and Consumers Energy's current inability to identify the amount of retirement costs that Wolverine has already paid to Consumers Energy or what retirement costs may still be outstanding, if any, Consumers Energy should be solely responsible for any remaining decommissioning costs at Campbell 3.

Q. Does this complete your pre-filed direct testimony at this time?

A. Yes.

U. S. DEPARTMENT OF AGRICULTURE
RURAL ELECTRIFICATION ADMINISTRATION

REA BORROWER DESIGNATION Michigan 46 Newaygo
Michigan 47 Cheboygan

THE WITHIN Ownership and Operating Agreement, dated August 15, 1980, between Northern Michigan Electric Cooperative, Inc., Wolverine Electric Cooperative, Inc., and Consumers Power Company

SUBMITTED BY THE ABOVE DESIGNATED BORROWER PURSUANT TO THE TERMS OF THE LOAN CONTRACT, IS HEREBY APPROVED SOLELY FOR THE PURPOSES OF SUCH CONTRACT.

Jos S. Fuller
FOR THE ADMINISTRATOR

DATED
8/29/80

CAMPBELL UNIT NO. 3

OWNERSHIP AND OPERATING AGREEMENT

BETWEEN

CONSUMERS POWER COMPANY

AND

NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

AND

WOLVERINE ELECTRIC COOPERATIVE, INC.

AUGUST 15, 1980

CAMPBELL UNIT NO. 3
OWNERSHIP AND OPERATING AGREEMENT

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CAMPBELL UNIT NO. 3
OWNERSHIP AND OPERATING AGREEMENT

AGREEMENT, entered into as of the 15th day of August, 1980, between CONSUMERS POWER COMPANY, a Michigan corporation, hereinafter called "CONSUMERS", and NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC., a Michigan corporation, hereinafter called "NORTHERN", and WOLVERINE ELECTRIC COOPERATIVE, INC., a Michigan corporation, hereinafter called "WOLVERINE". NORTHERN and WOLVERINE are hereinafter sometimes referred to individually as "COOPERATIVE" and collectively as "COOPERATIVES", as appropriate. CONSUMERS and NORTHERN and WOLVERINE are also hereinafter sometimes referred to individually as "PARTY" and collectively as "PARTIES", where appropriate.

WHEREAS, CONSUMERS and NORTHERN and WOLVERINE are public utilities engaged, among other things, in the generation, purchase, transmission and sale of electric energy, and

WHEREAS, CONSUMERS is engaged in the construction of a fossil fuel-fired steam electric generating unit (hereinafter referred to as "CAMPBELL 3") with a design nameplate turbine capability rating of 770 MW electric gross and an expected Net Demonstrated Capability of 791 MW electric, which is located in Ottawa County, Michigan, and

WHEREAS, CONSUMERS and the COOPERATIVES desire to enter into this Agreement for the purposes, among others, of establishing (1) the respective ownership interests of the PARTIES in the property included in CAMPBELL 3, and (2) the respective obligations and rights of the PARTIES with respect to the design, procurement, construction, operation and maintenance of CAMPBELL 3, and

WHEREAS, concurrently herewith CONSUMERS and NORTHERN and WOLVERINE have entered into (1) a separate agreement entitled "CAMPBELL UNIT NO. 3 BACK-UP REQUIREMENTS AGREEMENT" (hereinafter referred to as the "Campbell 3 Back-up Requirements Agreement") for the purpose of establishing the terms and conditions under which CONSUMERS is willing to make available to NORTHERN and WOLVERINE certain back-up electric capacity and energy during periods when CAMPBELL 3 is partially or totally out of service, and (2) a separate agreement entitled "CAMPBELL UNIT NO. 3 TRANSMISSION OWNERSHIP AND OPERATING AGREEMENT" (hereinafter referred to as the "Campbell 3 Transmission Agreement") for the purposes, among others, of establishing (a) the respective ownership interests of the PARTIES in certain 345 kV and higher voltage transmission lines, and (b) the respective obligations and rights of the PARTIES with respect to the design, procurement, construction, operation and maintenance of said 345 kV and higher voltage transmission lines, and

WHEREAS, it is the intention of the PARTIES to proceed in good faith and put forth their best efforts toward completion of CAMPBELL 3.

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein set forth, CONSUMERS and NORTHERN and WOLVERINE hereby agree as follows:

ARTICLE 1

DEFINITIONS

The following terms, when used herein and in the appendices attached hereto, shall have the following meanings:

1.1 Administrative Committee: The committee established pursuant to Article 16 hereof.

1.2 AFUDC: Allowance for funds used during construction.

1.3 Campbell A: A fossil fuel-fired combustion turbine electric generating unit, known as Campbell Unit A, owned by CONSUMERS on the CAMPBELL PLANT SITE with a nameplate turbine capability rating of 20.6 MW electric gross.

1.4 CAMPBELL 1: A fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 1, owned by CONSUMERS on the CAMPBELL PLANT SITE with a nameplate turbine capability rating of 265 MW electric gross.

1.5 CAMPBELL 2: A fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 2, owned by CONSUMERS on the CAMPBELL PLANT SITE with a nameplate turbine capability rating of 385 MW electric gross.

1.6 CAMPBELL 3: A fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 3, to be located on the CAMPBELL 3 SITE and the CAMPBELL PLANT SITE with a design nameplate turbine capability rating of 770 MW electric gross, consisting of all property included in CAMPBELL 3 as more specifically described in Appendices B and G attached hereto which may be revised from time to time.

1.7 CAMPBELL 3 SITE: The land which is described more particularly in Appendix A-1.

1.8 CAMPBELL PLANT SITE: Certain land, consisting of approximately 1,020 acres, and certain rights in land owned by CONSUMERS which surround the

CAMPBELL 3 SITE. The CAMPBELL PLANT SITE is more particularly described in Appendix A-2 and does not include the CAMPBELL 3 SITE.

1.9 Campbell Plant Site Transmission Facilities: The CAMPBELL 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the CAMPBELL 3 main power transformers to CONSUMERS' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the CAMPBELL 3 cranking transformer bank to CONSUMERS' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit. For purposes of this Agreement, the Campbell Plant Site Transmission Facilities are not a part of the property included in CAMPBELL 3.

1.10 Capital Improvements: Property which is an additional retirement unit installed after the Commercial Operation Date of CAMPBELL 3, a replacement of any retirement unit with another retirement unit after the Commercial Operation Date of CAMPBELL 3, a substantial addition to an existing retirement unit after the Commercial Operation Date of

CAMPBELL 3 (currently at least 10% of the original cost of such existing retirement unit) or a replacement of a portion of an existing retirement unit after the Commercial Operation Date of CAMPBELL 3 which increases the capacity, durability, efficiency and usefulness of such existing retirement unit. Retirement units are as described in the Federal Energy Regulatory Commission's "List of Units of Property for Use in Connection with the Uniform System of Accounts Prescribed for Public Utilities and Licensees" as adapted by CONSUMERS for its use, and as such List may be amended from time to time.

1.11 Capitalized Emergency Equipment: Major items held as spare parts for emergency or unusual use (as distinguished from ordinary maintenance due to wear) in connection with major equipment at specific locations which are of such a nature as to be properly includable in Plant Accounts of the Uniform System of Accounts. For an item to be classified as Capitalized Emergency Equipment at CAMPBELL 3, it must (a) be unique to CAMPBELL 3; (b) have a substantial current market price (currently at least $5,000, which amount may be adjusted by CONSUMERS to reflect changes in the market price of the least expensive items previously classified as Capitalized Emergency Equipment at CAMPBELL 3 or other locations on CONSUMERS' system); (c) have an extremely low failure rate and, therefore, be potentially never utilized; and (d) be critical to the continued operation of its associated major equipment, have a long lead time to obtain a replacement or have a limited number of suppliers. When classified as Capitalized Emergency Equipment, an item shall be assigned a service life that corresponds to that of its associated major equipment and its value depreciated over such associated major equipment's service life.

1.12 Closing: As explained in Section 4.1.

1.13 Commercial Operation Date: The date on which CAMPBELL 3 is determined by CONSUMERS to be reliable as a source of electric capacity and energy. Such determination shall be made by CONSUMERS in the same manner as is customary for CONSUMERS in determining the commercial operation date of any of its other fossil fuel-fired steam electric generating units.

1.14 Common Facilities: Facilities, and any additions thereto and any replacements, substitutions, improvements or betterments thereof, installed prior or subsequent to the Commercial Operation Date of CAMPBELL 3, including but not limited to those presently identified in Appendix G hereto, which CONSUMERS now or hereafter deems necessary or desirable for licensing, start-up, operation, maintenance, control, supply or shutdown of CAMPBELL 3 and for licensing, start-up, operation, maintenance, control, supply or shutdown of one or more other generating units now or hereafter installed in whole or in part on the CAMPBELL PLANT SITE. Common Facilities may be installed in whole or in part (a) on the CAMPBELL 3 SITE, (b) on the CAMPBELL PLANT SITE, or (c) beyond the boundaries of the CAMPBELL PLANT SITE.

1.15 Construction Insurance: Policies of insurance procured and maintained by CONSUMERS relating to CAMPBELL 3 up to its Commercial Operation Date, in accordance with Article 11 hereof.

1.16 Construction Work: All engineering, design, contract preparation, purchasing of equipment, materials and supplies, construction, supervision, expediting, inspection, accounting, testing and start-up for CAMPBELL 3 and preparation of operating and equipment manuals, quality assurance manuals, emergency action plans, all reports required by regulatory authorities and the conduct of hearings and other activities incidental to obtaining requisite permits, licenses and certificates for the construction and operation of CAMPBELL 3 prior to its Commercial Operation Date in accordance with Electric Plant Instruction No. 3, Components of Construction Cost, Uniform System of Accounts.

1.17 Consumers Distributable Construction Costs: Items whose costs are to be distributed as Consumers Distributable Construction Costs include materials, engineering and supervision expense; AFUDC as shown on CONSUMERS' books (accumulated through the 31st day of July, 1980, but not accumulated thereafter); administrative and general expense; taxes; and insurance. CONSUMERS' initial boiler and turbine contract payments shall be allocated to the boiler and turbine, respectively.

1.18 Contractor Distributable Construction Costs: Items in the electrical subsystem accounts of CONSUMERS' general contractor for CAMPBELL 3 whose costs are to be distributed as Contractor Distributable

Construction Costs include 6900 volt and 480 volt station and cranking power facilities; 120/250 volt direct current facilities; conduit; cable trays; duct banks; power, control and instrument cables; grounding facilities; cathodic protection facilities; heat tracing facilities; emergency power system; and coal handling, site and miscellaneous building lighting. Items in the miscellaneous subsystem accounts of CONSUMERS' general contractor for CAMPBELL 3 whose costs are to be distributed as Contractor Distributable Construction Costs include temporary construction facilities; miscellaneous construction services; construction equipment and tools; consumable supplies and utilities; payroll and field labor expense; field administration and home office expense; preliminary operations and testing; construction clearing accounts; premium time; permanent material suspense accounts; insurance claims; retentions and deposits; and engineering and procurement.

1.19 Electric capability: Megawatts (MW) electric.

1.20 Electric energy: Kilowatt hours (kWh).

1.21 Electric capability and energy: Electric capability and associated electric energy.

1.22 Net Demonstrated Capability: The maximum load which the generating unit can carry for a period of not less than two continuous hours during tests of such unit made by CONSUMERS from time to time under the operating steam conditions established by CONSUMERS for that unit and using the type and quality of fuel to be regularly fired. CAMPBELL 3 has an expected Net Demonstrated Capability of 791 MW electric.

1.23 Normal Capability: The maximum load level at which a generating unit can generally operate continuously. For the purposes of this Agreement, the Normal Capability of CAMPBELL 3 shall be deemed to be 95% of such unit's Net Demonstrated Capability. Such percentage shall not be changed unless and until accumulated operating evidence indicates that 95% is too high or low a percentage.

1.24 Operating Insurance: Policies of insurance procured and maintained by CONSUMERS relating to CAMPBELL 3 on and after its Commercial Operation Date, in accordance with Article 11 hereof.

1.25 Operating Work: All engineering, contract preparation, purchasing, repair, supervision, recruitment, training, expediting, inspection, accounting, testing, protection, operating, management, maintenance and all other work and activities associated with operating CAMPBELL 3 which are not included in Construction Work, but excluding all work undertaken to make any Capital Improvements.

1.26 Second Closing: As explained in Section 4.2.

1.27 Uniform System of Accounts: The Federal Energy Regulatory Commission's "Uniform System of Accounts Prescribed for Public Utilities and Licensees (Class A and Class B)", in effect as of the date of this Ownership and Operating Agreement, or as such Uniform System of Accounts may be modified from time to time. References in this

Ownership and Operating Agreement to any specific Account Number shall mean the Account Number in effect as of the effective date of this Ownership and Operating Agreement or any successor Account.

ARTICLE 2

OWNERSHIP INTERESTS AND SALE

2.1 Ownership Interests.

It is recognized by the PARTIES that CONSUMERS has disposed of 4.80% undivided ownership interest in CAMPBELL 3 to Michigan Public Power Agency pursuant to a separate Ownership and Operating Agreement between CONSUMERS and Michigan Public Power Agency dated as of October 1, 1979, as amended. It is agreed, as between CONSUMERS and the COOPERATIVES, that for purposes of this Agreement (i) CONSUMERS' ownership interest in CAMPBELL 3 and CONSUMERS' rights, duties and obligations to the COOPERATIVES, and the COOPERATIVES' rights, duties and obligations to CONSUMERS, under this Agreement shall be deemed to be the same as they would have been in the absence of such disposition of ownership interest by CONSUMERS to Michigan Public Power Agency, and (ii) all investment made by Michigan Public Power Agency in CAMPBELL 3 shall be added to and deemed a part of CONSUMERS' investment in CAMPBELL 3.

Upon occurrence of the Second Closing, the property included in CAMPBELL 3 shall be owned by the PARTIES as tenants in common. The undivided ownership interest of each PARTY in the property included in CAMPBELL 3 shall be free and clear of the lien of any indenture of mortgage, deed of trust or other instrument (hereinafter called "indenture") establishing a lien upon some or all of the property of the other PARTIES. For purposes of this Agreement, the undivided ownership interests of CONSUMERS, NORTHERN and WOLVERINE in the property included in CAMPBELL 3 shall be 98.11%, 1.26% and 0.63%, respectively. The property included in CAMPBELL 3 is more specifically described in Appendices B and G attached hereto which may be revised from time to time.

It is recognized by the PARTIES, however, that CONSUMERS may lease from others various items of property included in CAMPBELL 3, which are not directly associated with the production of electric energy, in lieu of purchasing such items of property. Such items of property may include, but are not limited to, tractors, front-end loaders, trucks, railroad locomotives, mobile cranes, forklift trucks, coal car heaters and blueprint machines. Nothing in this Agreement shall preclude CONSUMERS from leasing such items of property, and notwithstanding the provisions of the first paragraph of this Section 2.1 or any other provision of this Agreement, the PARTIES understand and agree that they will not have undivided ownership interests in such leased items of property and that CONSUMERS shall be under no obligation to convey to the COOPERATIVES any ownership interest in such leased items of property unless CONSUMERS purchases such leased items of property upon termination of the applicable leases. CONSUMERS and the COOPERATIVES shall share the benefit of such leased items of property in proportion to their respective ownership interests in CAMPBELL 3 in the same manner as though CONSUMERS had purchased such leased items instead of leasing them.

Notwithstanding the provisions of the first paragraph of this Section 2.1 or any other provision of this Agreement, the PARTIES understand and agree that for purposes of this Agreement the Campbell Plant Site Transmission Facilities are not a part of the property included in CAMPBELL 3.

2.2 Sale of Property Included in CAMPBELL 3.

At the Second Closing CONSUMERS shall sell and convey to NORTHERN and to WOLVERINE, and NORTHERN and WOLVERINE shall each purchase from CONSUMERS, an undivided ownership interest (being 1.26% in the case of NORTHERN and 0.63% in the case of WOLVERINE) as tenants in common in that portion of the property included in CAMPBELL 3 which is existing and identified as of the Conveyance Date. As used in this Agreement, the "Conveyance Date" shall mean the last day of the penultimate month preceding the month in which the Second Closing occurs; (for example, if the Second Closing occurs in January, 1981, the Conveyance Date will be November 30, 1980). Such conveyance shall be by Covenant Deeds and Bills of Sale substantially in the form shown in Exhibits A-1, A-2, A-3 and A-4, respectively, attached hereto and made a part hereof. Said Covenant Deeds shall be effective only to convey to NORTHERN and WOLVERINE their respective ownership interests in the realty of the CAMPBELL 3 SITE and the easement and right conveyed to CONSUMERS by instrument dated October 4, 1978 and recorded in Liber 847 at page 809, Ottawa County records, for the intake and transportation of water, easement rights for structures, equipment and facilities installed as a part of CAMPBELL 3 on the CAMPBELL PLANT SITE, and easement rights for Common Facilities on the CAMPBELL PLANT SITE; it being expressly agreed by the PARTIES that all property now or hereafter located on the CAMPBELL 3 SITE and the CAMPBELL PLANT SITE, whether or not annexed to the realty, shall be treated as personalty.

As soon as practicable after the final date that the Cost of Construction of CAMPBELL 3 is paid by CONSUMERS, taking into account the time required by CONSUMERS to apply for and obtain a properly executed release from the lien of CONSUMERS' indenture, CONSUMERS shall sell and convey to NORTHERN and to WOLVERINE, and NORTHERN and WOLVERINE shall each purchase from CONSUMERS, an undivided ownership interest (being 1.26% in the case of NORTHERN and 0.63% in the case of WOLVERINE) as tenants in common in the remainder of the property included in CAMPBELL 3. As used in this Agreement, the "remainder of the property included in CAMPBELL 3" shall mean that portion of the personal property included in CAMPBELL 3 which will be incorporated into CAMPBELL 3 and the costs of which will be included in the Cost of Construction of CAMPBELL 3, but which is not existing and identified as of the Conveyance Date. Such conveyance shall be by Bills of Sale substantially in the form shown in Exhibits A-5 and A-6 attached hereto and made a part hereof.

For purposes of this Agreement, prior to the Second Closing, wherever reference is made in this Agreement to (a) the ownership interest(s) of one or more of the PARTIES in CAMPBELL 3, (b) the ownership interest(s) of one or more of the PARTIES in the property included in CAMPBELL 3, (c) the percentage ownership interest(s) of one or more of the PARTIES in CAMPBELL 3, or (d) the percentage ownership interest(s) of one or more of the PARTIES in the property included in CAMPBELL 3, it is understood and agreed that such references pertain solely to the following percentage(s) with respect to such PARTY or PARTIES: 98.11% in the case of CONSUMERS, 1.26% in the case of NORTHERN and 0.63% in the case of WOLVERINE, as such percentage(s) may be modified pursuant to Sections 5.4.2, 9.8.2 or 17.1.

For purposes of this Agreement, on and after the Second Closing, wherever reference is made in this Agreement to (a) the ownership interest(s) of one or more of the PARTIES in CAMPBELL 3, (b) the ownership interest(s) of one or more of the PARTIES in the property included in CAMPBELL 3, (c) the percentage ownership interest(s) of one or more of the PARTIES in CAMPBELL 3, or (d) the percentage ownership interest(s) of one or more of the PARTIES in the property included in CAMPBELL 3, it is understood and agreed that such references pertain solely to the percentage ownership interest(s) of such PARTY or PARTIES in the property included in CAMPBELL 3 as set forth in Section 2.1 (i.e., 98.11% in the case of CONSUMERS, 1.26% in the case of NORTHERN and 0.63% in the case of WOLVERINE) as such percentage ownership interest(s) may be modified pursuant to Sections 5.4.2, 9.8.2, 13.2, 13.3, 13.4 or 17.1.

Further after the Second Closing, the PARTIES shall execute such other instruments, if any, as may be necessary or appropriate to confirm the ownership interests of NORTHERN and WOLVERINE respectively as tenants in common in the property included in CAMPBELL 3.

2.3 *Release From Lien of CONSUMERS' Indenture*.

At the Second Closing, CONSUMERS shall (a) furnish to NORTHERN a properly executed release of the undivided ownership interest (i.e., NORTHERN'S 1.26% undivided ownership interest) in that portion of the property included in CAMPBELL 3 being conveyed to NORTHERN at the Second Closing, from the lien of CONSUMERS' indenture dated as of September 1, 1945, as amended and supplemented, which is held by Citibank, N.A. (formerly First National City Bank, successor by merger to First National City Trust Company, formerly City Bank Farmers Trust Company) as Trustee, and (b) furnish to WOLVERINE a properly executed release of the undivided ownership interest (i.e., WOLVERINE'S 0.63% undivided ownership interest) in that portion of the property included in CAMPBELL 3 being conveyed to WOLVERINE at the Second Closing, from the lien of CONSUMERS' said indenture.

In addition, at the time of delivery of each Bill of Sale pursuant to the second paragraph of Section 2.2, CONSUMERS shall furnish to NORTHERN or WOLVERINE, whichever is the grantee in such Bill of Sale, a properly executed release of the undivided ownership interest in the remainder of the property included in CAMPBELL 3 being conveyed by such Bill of Sale to NORTHERN or WOLVERINE, as the case may be, from the lien of CONSUMERS' indenture dated as of September 1, 1945, as amended and supplemented, which is held by Citibank, N.A. (formerly First National City Bank, successor by merger to First National City Trust Company, formerly City Bank Farmers Trust Company) as Trustee.

2.4 Closing and Second Closing.

The Closing and Second Closing shall be held in accordance with the provisions of Article 4.

2.5 Additional Generating Units; Enlargements or Modifications of Existing Units.

CONSUMERS shall have the right to (a) install, enlarge, modify and operate any additional generating unit or units, including necessary appurtenances thereto, on the CAMPBELL PLANT SITE, and (b) enlarge, modify and operate any existing generating unit or units, including necessary appurtenances thereto, on the CAMPBELL PLANT SITE; provided that such additional or existing unit or units shall not be so installed, enlarged, modified and operated, as the case may be, as to unreasonably interfere with or burden the construction or operation of CAMPBELL 3. In the event that CONSUMERS determines to exercise any of its rights under the preceding sentence of this paragraph, CONSUMERS shall also have the right to use, enlarge, modify or relocate any facilities installed as a part of CAMPBELL 3 in connection with the installation, enlargement, modification or operation, as the case may be, of such additional unit or units or such existing unit or units: provided that (a) such use, enlargement, modification or relocation of CAMPBELL 3 facilities shall not unreasonably interfere with or burden the construction or operation of CAMPBELL 3; (b) if such use, enlargement, modification or relocation is of CAMPBELL 3 facilities which are to be jointly used by CAMPBELL 3 and such additional unit or units or existing unit or units, then (i) if said CAMPBELL 3 facilities are then listed as Common Facilities in Appendix G to this Agreement but the proposed joint use of said CAMPBELL 3 facilities is different from that stated for said facilities in Appendix G, then Appendix G shall be changed so as to reflect the proposed joint use of said CAMPBELL 3 facilities, or (ii) if said CAMPBELL 3 facilities are not then listed in Appendix G, then Appendix G shall be changed so as to reflect said CAMPBELL 3 facilities and the proposed joint use thereof; (c) the cost of such enlargement, modification or relocation of CAMPBELL 3 facilities shall be borne by CONSUMERS (except that if such enlargement, modification or relocation of CAMPBELL 3 facilities is in connection with the installation, enlargement, modification or operation of any additional unit or units which are owned or to be owned by the PARTIES in common, then the cost of such enlargement, modification or relocation of said CAMPBELL 3 facilities shall be shared by the PARTIES in proportion to their respective ownership interests in such additional unit or units); and (d) any net benefits and savings resulting from the joint use of CAMPBELL 3 facilities by CAMPBELL 3 and such additional unit or units or existing unit or units, if and when such joint use occurs, shall be allocated fairly among CAMPBELL 3 and such additional unit or units or existing unit or units, as the case may be, and the portion of such net benefits and savings which is allocated to CAMPBELL 3 shall be shared by the PARTIES in proportion to their respective ownership interests in CAMPBELL 3.

It is recognized by the PARTIES that CONSUMERS is designing and constructing some of the facilities being installed as a part of CAMPBELL 3 during its construction period so as to facilitate the possible future installation, enlargement, modification or operation, as the case may be, of an additional unit or units or an existing unit or units. Such designing and construction of said CAMPBELL 3 facilities by CONSUMERS shall not (i) be deemed an enlargement, modification or relocation of said CAMPBELL 3 facilities within the meaning of (a) and (c) of the second sentence of the first paragraph of this Section 2.5; (ii) enlarge or diminish the respective ownership interests of the PARTIES in any part of CAMPBELL 3 (except for any change in said ownership interests which may be required as a result of a change in Appendix G pursuant to (b) of said second sentence); (iii) enlarge or diminish their respective obligations to share in the costs of any part of CAMPBELL 3; or (iv) modify the provisions of (d) of said second sentence.

ARTICLE 3

PURCHASE AND PAYMENT

3.1 Purchase Price.

The purchase price for the COOPERATIVES' total 1.89% undivided ownership interest in the property included in CAMPBELL 3 which is existing and identified as of the Conveyance Date shall be an amount equal to (a) 1.89% of the accumulated Cost of Construction of CAMPBELL 3 as of the Conveyance Date, plus (b) an additional Sixty Thousand Dollars ($60,000) for other reasonable costs associated therewith. 126/189 of said purchase price shall be paid by NORTHERN; and the remaining 63/189 of said purchase price shall be paid by WOLVERINE.

A work order system is being used by CONSUMERS to cover the construction of CAMPBELL 3, the construction of the CAMPBELL 3 main power transformers and the construction of the non-CAMPBELL 3 portion of those Common Facilities which are being constructed in conjunction with CAMPBELL 3. Since the

Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated under said work order system will not be allocated to CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of said Common Facilities until after the Commercial Operation Date of CAMPBELL 3, it shall be assumed, for purposes of calculating said purchase price for the COOPERATIVES' total 1.89% undivided ownership interest in the property included in CAMPBELL 3 as of the Conveyance Date, that 91% of said Contractor Distributable Construction Costs and said materials, engineering and supervision portion of Consumers Distributable Construction Costs which are accumulated as of the Conveyance Date will be allocated to CAMPBELL 3. However, since the aforesaid 91% is an assumed percentage, the portion of said purchase price which is represented by 1.89% of the accumulated Cost of Construction of CAMPBELL 3 as of the Conveyance Date shall be subject to later adjustment as provided in Section 3.7 hereof.

Based in part on the assumed percentage allocation of said Contractor Distributable Construction Costs and said materials, engineering and supervision portion of Consumers Distributable Construction Costs to CAMPBELL 3 as set forth in the second paragraph of this Section 3.1, the accumulated Cost of Construction of CAMPBELL 3 through May 31, 1980 was $527,667,000 as summarized in Appendix C.

The purchase price for each COOPERATIVE'S undivided ownership interest (being 1.26% in the case of NORTHERN and 0.63% in the case of WOLVERINE) in the remainder of the property included in CAMPBELL 3 shall be the aggregate of all payments which such COOPERATIVE is obligated to make pursuant to this Article 3 for its share of the Cost of Construction of CAMPBELL 3 after the Conveyance Date.

3.2 <u>Cost of Construction</u>.

For purposes of this Agreement, the Cost of Construction of CAMPBELL 3 shall include all the costs incurred by CONSUMERS in the planning, design, licensing, acquisition, construction, and completion of CAMPBELL 3 including, without limitation, the CAMPBELL 3 SITE, the fossil-fired steam generator, turbine generator and building housing the same, all auxiliary buildings and equipment, pollution control facilities (whether or not legal title is vested in any governmental authority), the control and communications facilities, Capitalized Emergency Equipment, and the CAMPBELL 3 portion of all Common Facilities (whether existing or under construction) as set forth in Appendix G. Said costs shall include, without limitation, all planning, design, engineering, licensing and acquisition costs; all costs for land, rights in land, structures, facilities and equipment; all costs for supervision; all costs for construction equipment, tools, materials, supplies and labor; overheads; AFUDC as shown on CONSUMERS' books (accumulated through the 31st day of July, 1980, but not accumulated thereafter); property taxes and other taxes except income taxes; and insurance. It is understood and agreed, however, that the costs of the portion of each existing Common Facility which is allocated to CAMPBELL 3 as provided for in Appendix G, shall be the original cost of the CAMPBELL 3 portion of said Common Facility less related accumulated depreciation to the Conveyance Date determined in accordance with rates of depreciation approved for CONSUMERS by the Michigan Public Service Commission, except that it is recognized by the PARTIES that no depreciation is applicable to the CAMPBELL PLANT SITE.

CONSUMERS has furnished the COOPERATIVES a statement reflecting the Cost of Construction attributable to CAMPBELL 3 through May 31, 1980. Said statement, which is attached hereto as Appendix C, is based in part on the assumed percentage allocation of said Contractor Distributable Construction Costs and said materials, engineering and supervision portion of Consumers Distributable Construction Costs to CAMPBELL 3 as set forth in the second paragraph of Section 3.1. A similar statement, covering Cost of Construction of CAMPBELL 3 for the month of June, 1980 shall be furnished to the COOPERATIVES prior to the Closing; and a similar statement, covering Cost of Construction of CAMPBELL 3 for the period of July 1, 1980 to the Conveyance Date shall be furnished to the COOPERATIVES prior to the Second Closing.

3.3 Payment - Purchase Price.

NORTHERN and WOLVERINE shall pay at the Closing, in immediately available funds, a deposit on their respective shares of the purchase price for their total 1.89% undivided ownership interest in the property included in CAMPBELL 3 which is existing and identified as of the Conveyance Date. Said deposit shall be an amount equal to (a) 1.89% of the accumulated Cost of Construction of CAMPBELL 3 as of June 30, 1980, plus (b) the additional Sixty Thousand Dollars ($60,000) which is referred to in (b) of the first paragraph of Section 3.1.

After the Closing, the COOPERATIVES shall make monthly payments to CONSUMERS as provided in Section 3.5. All such monthly payments of Cost of Construction of CAMPBELL 3 incurred between July 1, 1980 and the Conveyance Date shall be deemed to be supplemental deposits on the purchase price for the COOPERATIVES' total 1.89% undivided ownership interest in the property included in CAMPBELL 3 which is existing and identified as of the Conveyance Date.

As is stated in the second paragraph of Section 3.1 above, the portion of said purchase price which is represented by 1.89% of the accumulated Cost of Construction of CAMPBELL 3 as of the Conveyance Date shall be subject to later adjustment as provided in Section 3.7 hereof.

CONSUMERS and the COOPERATIVES shall have until the 180th day after the Second Closing to question or contest the correctness of (a) the accumulated Cost of Construction of CAMPBELL 3 as of the Conveyance Date other than any portion thereof which is included in (b) of this sentence, and (b) the accumulated Contractor Distributable Construction Costs and the accumulated materials, engineering and supervision portion of Consumers Distributable Construction Costs as of the Conveyance Date under the work order system covering the construction of CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of those Common Facilities which are being constructed in conjunction with CAMPBELL 3, after which time the correctness of the costs referred to in (a) and (b) of this sentence shall be conclusively established. In the event of an error in calculation of said costs referred to in said (a) and (b), CONSUMERS or the COOPERATIVES shall, following notice of such erroneous calculations from the other, within 45 days reimburse the other for the amount of the purchase price for the COOPERATIVES' total 1.89% undivided ownership interest in the property included in CAMPBELL 3 as of the Conveyance Date which has been overcharged or undercharged as a result of such erroneous calculations.

3.4 Sharing of Cost of Construction After the Conveyance Date.

Subsequent to the Second Closing, the Cost of Construction of CAMPBELL 3 after the Conveyance Date shall be shared by CONSUMERS and the COOPERATIVES in proportion to their respective percentage ownership interests in the property included in CAMPBELL 3. For purposes of making estimates and payments of such Cost of Construction of CAMPBELL 3 subsequent to the Second Closing, it shall be assumed that 91% of the Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated after the Conveyance Date under the work order system referred to in the second paragraph of Section 3.1 will be allocated to CAMPBELL 3. Since the aforesaid 91% is an assumed percentage, the payments made by the COOPERATIVES for their share of such Cost of Construction of CAMPBELL 3 after the Conveyance Date shall be subject to later adjustment as provided in Section 3.7 hereof. An estimate of the total cost of CAMPBELL 3, of the cost incurred therefor by CONSUMERS through May 31, 1980 and an estimate of the amount remaining to be spent is attached hereto as Appendix D. Said estimates are based in part on the assumed percentage allocation of Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs to CAMPBELL 3 as set forth in the second paragraph of Section 3.1 and in this Section 3.4.

3.5 <u>*Estimates and Payments of Cost of Construction After June 30, 1980.*</u>

During the period between June 30, 1980 and the final date that all Cost of Construction of CAMPBELL 3 is paid by CONSUMERS, quarterly estimates of payments required from the COOPERATIVES for their share of the Cost of Construction of CAMPBELL 3 after June 30, 1980 shall be furnished by CONSUMERS in reasonable detail to the COOPERATIVES for use by them in anticipating their financial requirements. In addition, estimated costs by months for the twelve months of each calendar year shall be prepared and submitted to the COOPERATIVES prior to the beginning of such calendar year; (i.e., prior to December 31, 1980 monthly estimates will be furnished covering January through December 1981; prior to December 31, 1981 monthly estimates will be furnished covering January through December 1982, etc.). The initial quarterly forecast shall be on or before the Closing. All estimates shall be subject to revision periodically to reflect more current information on Cost of Construction. Payment by the COOPERATIVES of their share of the Cost of Construction after June 30, 1980 shall be made as follows:

3.5.1 On or before the 15th day of each month, commencing with the month of August, 1980, CONSUMERS shall furnish the COOPERATIVES an invoice showing the current estimate of payments, and the COOPERATIVES' share thereof, which CONSUMERS expects to make the following month. The first of such invoices shall also show the current estimate of payments, and the COOPERATIVES' share thereof, required for the period from June 30, 1980 to August 31, 1980.

3.5.2 These invoices shall be paid by the COOPERATIVES so that CONSUMERS will receive the funds by the 9th day of the following month or the first working day thereafter if the payment date falls on other than a working day.

3.5.3 Adjustments for the difference between estimated payments and actual costs shall be made on the invoice submitted for the third month following the month in which the actual costs occurred. However, adjustments for the difference between estimated payments and actual costs for the period from June 30, 1980 to August 31, 1980 shall be made on the invoice submitted for the month of November, 1980.

3.5.4 All payments shall be made in immediately available funds payable to Consumers Power Company and shall be sent to Consumers Power Company, Attention: Treasurer, 212 West Michigan Avenue, Jackson, Michigan 49201, or by wire transfer to a bank designated by CONSUMERS.

3.5.5 Any payment not made on or before the due dates set forth in Section 3.5.2 shall constitute an act of default under Section 17.1 hereof.

3.6 <u>Allocation of Contractor Distributable Construction Costs and the Materials, Engineering and Supervision Portion of Consumers Distributable Construction Costs Accumulated under Work Order System.</u>

The Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated under the work order system referred to in the second paragraph of Section 3.1 shall be allocated by CONSUMERS to CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of those Common Facilities which are being constructed in conjunction with CAMPBELL 3, as soon as practicable after the final date that all Cost of Construction of CAMPBELL 3 is paid by CONSUMERS, using the following procedure:

3.6.1 The portion of Contractor Distributable Construction Costs that are direct labor and materials distributables shall be accumulated in specific accounts designated for that purpose for CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of said Common Facilities, and shall be distributed as appropriate to Accounts 310-316 (hereinafter called "prime accounts") of the Uniform System of Accounts as directed by CONSUMERS' general contractor for CAMPBELL 3 following the Commercial Operation Date of CAMPBELL 3. The remaining Contractor Distributable Construction Costs (i.e., engineering and other indirect costs) shall be allocated among all of the prime accounts used to record the Cost of Construction of CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of said Common Facilities with a share being assigned to each prime account in the proportion that the total costs accumulated in that prime account bear to the total costs accumulated in all of the prime accounts used to record the Cost of Construction of CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of said Common Facilities.

3.6.2 The materials, engineering and supervision portion of Consumers Distributable Construction Costs shall be allocated among all of the prime accounts used to record the Cost of Construction of CAMPBELL 3, the CAMPBELL 3 main power transformers and the non-CAMPBELL 3 portion of said Common Facilities using the same proportions as established for the remaining Contractor Distributable Construction Costs under the second sentence of Subsection 3.6.1.

CONSUMERS shall promptly give the COOPERATIVES written notice of said allocation after it has been determined, including a work sheet showing in reasonable detail the calculations made by CONSUMERS in determining said allocation.

3.7 Adjustments to Purchase Price for the COOPERATIVES' Total 1.89% Undivided Ownership Interest in the Property Included in CAMPBELL 3 as of the Conveyance Date, and Payments Made After the Conveyance Date.

If, pursuant to Section 3.6, the Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated under the work order system referred to in the second paragraph of Section 3.1 are allocated to CAMPBELL 3 in a percentage which is greater or less than the assumed 91%, then all amounts owing by CONSUMERS to the COOPERATIVES, or by the COOPERATIVES to CONSUMERS, as a result of such allocation, shall be due and payable within 45 days following receipt by the COOPERATIVES of the written notice referred to in Section 3.6 hereof.

CONSUMERS and the COOPERATIVES shall have until the 180th day after said written notice to question or contest the correctness of (a) the Cost of Construction of CAMPBELL 3 accumulated after the Conveyance Date other than any portion thereof which is included in (b) of this sentence, (b) the Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated after the Conveyance Date under the work order system referred to in the second paragraph of Section 3.1, and (c) the allocation made by CONSUMERS under Section 3.6 of the Contractor Distributable Construction Costs and the materials, engineering and supervision portion of Consumers Distributable Construction Costs accumulated prior to and after the Conveyance Date under the work order system referred to in the second paragraph of Section 3.1, after which time the correctness of the costs referred to in (a) and (b) of this sentence and the allocation referred to in (c) of this sentence shall be conclusively established. In the event of an error in calculation of said costs referred to in (a) and (b) of the previous sentence or in calculation of said allocation referred to in (c) of the previous sentence, as the case may be, CONSUMERS or the COOPERATIVES shall, following notice of such erroneous calculations from the other, within 45 days reimburse the other for any amounts which have been overcharged or undercharged as a result of such erroneous calculations.

3.8 Capital Improvements Made to CAMPBELL 3 After Its Commercial Operation Date.

Subsequent to the Commercial Operation Date of CAMPBELL 3, the costs of each Capital Improvement made to CAMPBELL 3 shall be shared by CONSUMERS and the COOPERATIVES in proportion to their respective percentage ownership interests in CAMPBELL 3.

Prior to the making of each Capital Improvement to CAMPBELL 3, an estimate of the costs of such Capital Improvement shall be made by CONSUMERS. Such estimate shall be furnished by CONSUMERS in reasonable detail to the COOPERATIVES for use by them in anticipating their financial requirements. Such estimate shall be subject to revision periodically to reflect more current information on such Capital Improvement. Payments for such Capital Improvement shall be made in accordance with Section 7.3 hereof.

ARTICLE 4

CLOSING AND SECOND CLOSING

4.1 Closing.

4.1.1 Date - Place.

Subject to the conditions precedent referred to in Section 9.4 hereof, the Closing shall take place at such location as may be agreed upon by the PARTIES, on a mutually acceptable date (which shall not be later than August 29, 1980) to be determined by the PARTIES.

If the Closing does not occur on or before August 29, 1980, then this Agreement shall be void ab initio.

4.1.2 Delivery of Documents, Certificates and Funds.

At the Closing, CONSUMERS shall deliver to NORTHERN and WOLVERINE all certificates and evidences of authorizations and approvals as provided for in Section 9.4; NORTHERN and WOLVERINE shall deliver to CONSUMERS their respective shares of the deposit on the purchase price, to be paid at the Closing, in immediately available funds and all certificates and evidences of authorizations and approvals as provided for in Section 9.4. It is specifically understood and agreed that no conveyance of any of the property included in CAMPBELL 3 shall take place at the Closing; and the COOPERATIVES shall have no ownership interest in such property until the occurrence of the Second Closing.

4.2 Second Closing.

4.2.1 Date - Place.

Subject to the conditions precedent referred to in Section 9.5 hereof, the Second Closing shall take place at such location as may be agreed upon by the PARTIES, on a mutually acceptable date (which shall not be later than February 1, 1981) to be determined by the PARTIES.

If the Second Closing does not occur on or before February 1, 1981, and CONSUMERS' retail electric rates do not then reflect the rate base and cost of service associated with the total 1.89% ownership interest in CAMPBELL 3 which would have been conveyed to the COOPERATIVES had the Second Closing occurred on or before February 1, 1981, then CONSUMERS shall seek in a general electric rate proceeding, or in a special rate proceeding, the accounting and rate making treatment from the MPSC necessary to reflect such rate base and cost of service in CONSUMERS' retail electric rates. Further, if the Second Closing does not occur on or before February 1, 1981, the COOPERATIVES shall continue their interim short-term financing with National Rural Utilities Cooperative Finance Corporation (CFC) until (i) the effective date of a final MPSC order, whenever issued, which increases rates for CONSUMERS' retail electric service to recognize such additional 1.89% ownership interest in CAMPBELL 3, or (ii) the effective date of a final MPSC order issued after February 1, 1981, in a general electric rate proceeding (other than Case No. U-5979 now pending before the MPSC) in which CONSUMERS requests the accounting and rate making treatment from the MPSC necessary to reflect such rate base and cost of service in CONSUMERS' retail electric rates, or (iii) July 23, 1982, whichever of (i), (ii) or (iii) occurs first.

Upon the occurrence of the earliest of (i), (ii) or (iii), referred to in the next preceding paragraph, the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 shall cease and terminate. Further, upon the occurrence of the earliest of said (i), (ii) or (iii), the COOPERATIVES shall not be obligated to share in any of the following costs, expenses, payments, obligations or taxes to the extent that the circumstances, events or basis of the same occur or arise after the occurrence of the earliest of said (i), (ii) or (iii): Operating Costs of CAMPBELL 3; costs of Capital Improvements; insurance costs; liability payments, costs, expenses or obligations; taxes other than income taxes and those taxes included in Operating Costs of CAMPBELL 3; and retirement costs.

Within 30 days after the occurrence of the earliest of said (i), (ii) or (iii), CONSUMERS shall pay to the COOPERATIVES an amount equal to (a) the \$60,000 referred to in the first paragraph of Section 3.1 and all amounts received by CONSUMERS from the COOPERATIVES for their shares of the Cost of Construction of CAMPBELL 3, plus (b) interest and charges paid by the COOPERATIVES to the CFC for interim short-term financing of the amounts referred to in (a) above up to and including the day immediately preceding the Commercial Operation Date of CAMPBELL 3 but not thereafter, plus (c) all amounts paid by the COOPERATIVES to CONSUMERS for the COOPERATIVES' share of the coal remaining in the stockpile for CAMPBELL 3, minus (d) the COOPERATIVES' depreciation expenses, as authorized by the MPSC, as a result of the COOPERATIVES' investments in CAMPBELL 3, plus (e) interest on the aggregate net amount of (a), (b), (c) and (d) above, from the occurrence of the earliest of said (i), (ii) or (iii) up to and including the day immediately preceding the day on which payment is made by CONSUMERS to the COOPERATIVES in accordance with this paragraph but not thereafter, at a rate of interest per annum (computed on the basis of a year of 365 days) equal to the lowest prime rate published in the "Money" column of the <u>New York Times</u> in its last publication of that column in the month next preceding the month in which such payment is made by CONSUMERS to the COOPERATIVES, plus one and one-half per cent per annum; and upon such payment by CONSUMERS to the COOPERATIVES this Agreement shall be deemed to have expired. The portion of such payment to which NORTHERN is entitled shall be made in immediately available funds payable to Northern Michigan Electric Cooperative, Inc. and shall be sent to Northern Michigan Electric Cooperative, Inc., Attention: General Manager, Post Office Box 138, Boyne City, Michigan 49712, or by wire transfer to a bank designated by NORTHERN. The portion of such payment to which WOLVERINE is entitled shall be made in immediately available funds payable to Wolverine Electric Cooperative, Inc. and shall be sent to Wolverine Electric Cooperative, Inc., Attention: General Manager, Post Office Box 1133, Big Rapids, Michigan 49301, or by wire transfer to a bank designated by WOLVERINE. If any portion of such payment is not made within 30 days after the occurrence of the earliest of said (i), (ii) or (iii), such portion shall bear interest at the rate of 1% per month or the highest lawful rate, whichever is lower.

4.2.2 Delivery of Documents and Certificates.

At the Second Closing, CONSUMERS shall deliver to NORTHERN and WOLVERINE the Covenant Deeds and Bills of Sale to be delivered at the Second Closing, the releases by Citibank, N.A. (formerly First National City Bank, successor by merger to First National City Trust Company, formerly City Bank Farmers Trust Company) as Trustee under CONSUMERS' indenture dated as of September 1, 1945, as amended and supplemented, of the ownership interests in the property included in CAMPBELL 3 to be conveyed to NORTHERN and WOLVERINE hereunder at the Second Closing from the lien of such indenture, and all certificates and evidences of authorizations and approvals as provided for in

Section 9.5; NORTHERN and WOLVERINE shall deliver to CONSUMERS all certificates and evidences of authorizations and approvals as provided for in Section 9.5.

ARTICLE 5

REPRESENTATIONS, WARRANTIES AND MUTUAL COVENANTS

5.1 NORTHERN Representations.

NORTHERN hereby represents and warrants to CONSUMERS as follows:

5.1.1 NORTHERN Organization.

NORTHERN is a corporation duly organized, validly existing and in good standing under the laws of the State of Michigan and has corporate power to carry on its business as it is now being conducted and as it is contemplated to be conducted after the Closing. NORTHERN has delivered to CONSUMERS on or before the Closing, a true and complete copy of its charter and by-laws as amended to date.

5.1.2 Authority Relative to This Agreement.

The execution, delivery and performance of this Agreement by NORTHERN has been duly and effectively authorized by all requisite corporate action.

5.2 WOLVERINE Representations.

WOLVERINE hereby represents and warrants to CONSUMERS as follows:

5.2.1 WOLVERINE Organization.

WOLVERINE is a corporation duly organized, validly existing and in good standing under the laws of the State of Michigan and has corporate power to carry on its business as it is now being conducted and as it is contemplated to be conducted after the Closing. WOLVERINE has delivered to CONSUMERS on or before the Closing, a true and complete copy of its charter and by-laws as amended to date.

5.2.2 Authority Relative to This Agreement.

The execution, delivery and performance of this Agreement by WOLVERINE has been duly and effectively authorized by all requisite corporate action.

5.3 CONSUMERS Representations.

CONSUMERS hereby represents and warrants to NORTHERN and WOLVERINE as follows:

5.3.1 CONSUMERS Organization.

CONSUMERS is a corporation duly organized, validly existing and in good standing under the laws of the State of Michigan and has corporate power to carry on its business as it is now being conducted and as it is contemplated to be conducted after the Closing. CONSUMERS has delivered to NORTHERN and WOLVERINE on or before the Closing, a true and complete copy of its charter and by-laws as amended to date.

5.3.2 Authority Relative to This Agreement.

The execution, delivery and performance of this Agreement by

CONSUMERS has been duly and effectively authorized by all requisite corporate action.

5.4 Mutual Covenants.

CONSUMERS and NORTHERN and WOLVERINE hereby covenant and agree as follows:

5.4.1 Authority for Completion of Construction.

CONSUMERS shall have sole authority, to be discharged in accordance with the provisions of this Agreement and consistent with the normal practices and procedures observed by CONSUMERS with respect to its other fossil fuel-fired steam electric generating units, for the planning, design, licensing, acquisition, Construction Work and testing of CAMPBELL 3. Regardless of any considerations applicable to other electric generating plant projects under construction by CONSUMERS, CONSUMERS shall use its reasonable best efforts to the extent permitted by law, and subject to the other provisions of this Agreement, to complete construction and place CAMPBELL 3 in commercial operation by October 15, 1980, and to comply fully with all requirements of all applicable statutes and the rules and regulations of such regulatory agencies as shall have competent jurisdiction over the planning, design, licensing, acquisition, Construction Work and testing of CAMPBELL 3.

5.4.2 *Financial Inability of CONSUMERS.*

In the event of financial inability on the part of CONSUMERS to complete construction of CAMPBELL 3 in accordance with reasonable construction schedules and this Agreement, CONSUMERS shall promptly so notify the COOPERATIVES in writing of such condition. Upon receipt of such written notice, the COOPERATIVES, or either of them, shall have the right, subject to all governmental and regulatory approval, to invest additional funds in sufficient amount to complete construction of CAMPBELL 3. In the event the COOPERATIVES, or either of them, invests the additional funds to complete construction of CAMPBELL 3 because of CONSUMERS' inability to do so, then the percentage ownership interest in CAMPBELL 3 of each of the COOPERATIVES making such additional investment shall be adjusted in accordance with the following formula:

$$E = \frac{C_2}{C_1 + C_2 + C_3} \times E_c$$

Where E = Additional percentage ownership interest accruing to the COOPERATIVE as a result of making its additional investment in CAMPBELL 3 (there shall be a corresponding reduction in the percentage ownership interest of CONSUMERS in CAMPBELL 3).

C_1 = Investment, excluding AFUDC, made by CONSUMERS for its percentage ownership interest in CAMPBELL 3 up to the time of the written notice first referred to in this Section 5.4.2.

C_2 = Additional investment, excluding AFUDC, made by such COOPERATIVE to complete construction of CAMPBELL 3 because of CONSUMERS' inability to do so.

C_3 = Additional investment, if any, excluding AFUDC, made by the other COOPERATIVE to complete construction of CAMPBELL 3 because of CONSUMERS' inability to do so.

E_c = CONSUMERS' percentage ownership interest in CAMPBELL 3 at the time of the written notice first referred to in this Section 5.4.2.

Beginning with the Commercial Operation Date of CAMPBELL 3, CONSUMERS shall purchase an amount of the net electric generating capability of CAMPBELL 3 (hereinafter called "CAMPBELL 3 Unit Capability") from each COOPERATIVE, which made such additional investment because of CONSUMERS' inability to do so, such amount of CAMPBELL 3 Unit Capability to be determined by multiplying that COOPERATIVE'S increase in percentage ownership interest times the net electric generating capability of CAMPBELL 3. CONSUMERS shall make monthly payments to such COOPERATIVE for such CAMPBELL 3 Unit Capability, such payments to be determined in accordance with the following formula and as illustrated in Appendix E hereto:

Monthly Payment for CAMPBELL 3 Unit Capability from Commercial Operation Date of CAMPBELL 3 until the end of the period during which CONSUMERS must purchase CAMPBELL 3 Unit Capability $= \frac{1}{12}\left[\frac{(F_c + F_p)}{2} \times C + A\right] + A_f$

Where F_c = Annual fixed charge factor for CONSUMERS determined for each calendar year in which such monthly payments are to be made. Such annual fixed charge factor expressed as a decimal shall include (a) overall rate of return on applicable net investment which is determined on the basis of (i) the imbedded cost of debt and preferred and preference stock, (ii) the rate of return on common equity on which CONSUMERS' wholesale for resale electric rates approved, or permitted to become effective in a final order, by the Federal Energy Regulatory Commission, or any successor agency or department, are based, and (iii) the capitalization ratios derived from Capitalization as shown in CONSUMERS' Annual Report to its stockholders with appropriate adjustment to such Capitalization for Current Obligations and Sinking Fund Requirement, and (b) applicable taxes, i.e., federal income tax, the income and interest portions of the Michigan Single Business Tax, or any other applicable tax not accounted for in this sentence. Such annual fixed charge factor for each calendar year in which such monthly payments are to be made shall be based on the year-end data for the immediately preceding calendar year.

F_p = The COOPERATIVE'S annual fixed charge factor expressed as a decimal shall include (a) financing cost associated with CAMPBELL 3 and (b) applicable taxes associated with CAMPBELL 3, i.e., federal income tax, if any, the income and interest portions of the Michigan Single Business Tax, or any other applicable tax not accounted for in this sentence or in A. Prior to the Second Closing, the term "financing cost associated with CAMPBELL 3", as used in (a) of the preceding sentence, shall mean the cost of short term debt associated with CAMPBELL 3; and on and after the Second Closing, said term "financing cost associated with CAMPBELL 3", as used in (a) of said preceding sentence, shall mean the weighted cost of long term debt associated with CAMPBELL 3. Except as otherwise provided in the next following three sentences, such annual fixed charge factor for each calendar year, in which such monthly payments are to be made, shall be based on the year-end data for the immediately preceding calendar year. During the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, such annual fixed charge factor shall be determined in each calendar month, for which such a monthly payment is to be made, based on the month-end data for the immediately preceding calendar month. For the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, in which such monthly payments are to be made, such annual fixed charge factor shall be based on data available as of the Second Closing. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then during the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy

Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, such annual fixed charge factor shall be determined in each calendar month, for which such a monthly payment is to be made, based on the month-end data for the immediately preceding calendar month.

C = Except as otherwise provided in the next following three sentences, C shall be the additional average net investment for the calendar year in which such monthly payments are to be made, including AFUDC, made by the COOPERATIVE in order to complete construction of the property included in CAMPBELL 3 because of CONSUMERS' inability to do so, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory associated with its additional investment in CAMPBELL 3 for such calendar year. During the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, C shall be determined in each calendar month, for which such a monthly payment is to be made, and shall be the additional average net investment for such calendar month, including AFUDC, made by the COOPERATIVE in order to complete construction of the property included in CAMPBELL 3 because of CONSUMERS' inability to do so, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory associated with its additional investment in CAMPBELL 3 for such calendar month. For the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, C shall be the additional average net investment for said period in which such monthly payments are to be made, including AFUDC, made by the COOPERATIVE in order to complete construction of the property included in CAMPBELL 3 because of CONSUMERS' inability to do so, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory associated with its additional investment in CAMPBELL 3 for said period. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then during the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, C shall be determined in each month, for which such a payment is to be made, and shall be the additional average net investment for such calendar month, including AFUDC, made by the COOPERATIVE in order to complete construction of the property included in CAMPBELL 3 because of CONSUMERS' inability to do so, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory associated with its additional investment in CAMPBELL 3 for such calendar month.

A = Expenses incurred by the COOPERATIVE, for each calendar year in which such monthly payments are to be made, as a result of its additional investment in the property included in CAMPBELL 3. Such expenses incurred by the COOPERATIVE as a result of its additional investment in the property included in CAMPBELL 3 shall include (a) depreciation expense, including any retirement costs (as provided for in Section 20.2), as authorized by the Michigan Public Service Commission or any successor agency or department, (b) Operating Costs, (c) property taxes, (d) insurance, (e) liability expenses, if any, and (f) any other appropriate expense that may be incurred by the COOPERATIVE as a result of its additional investment in the property included in CAMPBELL 3.

A_f = Fuel expense incurred by the COOPERATIVE for the electric energy associated with the CAMPBELL 3 Unit Capability purchased by CONSUMERS in the month for which such payment is being made.

F_c, F_p, C, A and A_f may have to be estimated for purposes of applying the above formula. In the event that (a) the actual value of F_c for the calendar year in which such monthly payments are to be made, based on the year-end data for the immediately preceding calendar year, differs from the estimated value thereof, (b) the actual value of F_p or C, for the calendar year or other period, as set forth in F_p or C, in which such monthly payments are to be made, differs from the estimated value thereof, (c) the actual value of A, at any time during the calendar year in which such monthly payments are to be made, differs from the estimated value thereof, or (d) the actual value of A_f in any month in which such payments are to be made, differs from the estimated value thereof, then in any such event an adjustment shall be made for any overpayments or underpayments which result from such difference.

Unless a net invoice procedure is utilized pursuant to Section 6.11, payment by CONSUMERS of the monthly payment for each COOPERATIVE'S CAMPBELL 3 Unit Capability, excepting the portion thereof represented by A_f, shall be made as follows:

(1) On or before the 15th day of each month, beginning with the month next preceding the month in which CAMPBELL 3 goes into commercial operation, the COOPERATIVE shall furnish CONSUMERS an invoice showing the payment, excepting the portion thereof represented by A_f, required for the following month. The first month's payment, excepting the portion thereof represented by A_f, required for such CAMPBELL 3 Unit Capability shall be adjusted to reflect the actual Commercial Operation Date of CAMPBELL 3. The payment for the month in which the Second Closing occurs, excepting the portion thereof represented by A_f, required for such CAMPBELL 3 Unit Capability shall be adjusted to reflect the actual date of the Second Closing. If the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then the payment for the month in which the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and

terminate pursuant to Section 4.2.1, excepting the portion thereof represented by A_f, required for such CAMPBELL 3 Unit Capability shall be adjusted to reflect the actual date of such cessation and termination of the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3.

(2) Any adjustment resulting from the difference between the actual value of F_c from the estimated value thereof, as set forth in the second paragraph of this Section 5.4.2, shall be reflected in the invoice submitted in May of each calendar year in which such difference occurs.

Except as otherwise provided in the next following three sentences, any adjustment resulting from the difference between the actual value of F_p from the estimated value thereof, as set forth in the second paragraph of this Section 5.4.2, shall be reflected in the invoice submitted in May of each calendar year in which such difference occurs. If any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, the adjustment for such difference shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred. If any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, the adjustment for such difference shall be reflected in the invoice submitted in June of 1981. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then if any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, then the adjustment for such difference shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

Any adjustment resulting from the difference between the actual value of C or A from the estimated value thereof, as set forth in the second paragraph of this Section 5.4.2, shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

(3) These invoices shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 9th day of the following month or the first working day thereafter if the payment date falls on other than a working day.

Unless a net invoice procedure is utilized pursuant to Section 6.11, payment by CONSUMERS of the portion of the monthly payment for each COOPERATIVE'S CAMPBELL 3 Unit Capability which is represented by A_f shall be made as follows:

(1) On or before the 5th day of each month, beginning with the month in which CAMPBELL 3 goes into commercial operation, the COOPERATIVE shall furnish CONSUMERS an invoice showing the payment required for A_f for such month. The first month's payment required for A_f shall be adjusted to reflect the actual Commercial Operation Date of CAMPBELL 3.

(2) Any adjustment resulting from the difference between the actual value of A_f from the estimated value thereof, as set forth in the second paragraph of this Section 5.4.2, shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

(3) These invoices shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 25th day of such

month or the first working day thereafter if the payment date falls on other than a working day.

All payments made to NORTHERN under this Section 5.4.2 shall be made in immediately available funds payable to Northern Michigan Electric Cooperative, Inc. and shall be sent to Northern Michigan Electric Cooperative, Inc., Attention: General Manager, Post Office Box 138, Boyne City, Michigan 49712, or by wire transfer to a bank designated by NORTHERN. All payments made to WOLVERINE under this Section 5.4.2 shall be made in immediately available funds payable to Wolverine Electric Cooperative, Inc. and shall be sent to Wolverine Electric Cooperative, Inc., Attention: General Manager, Post Office Box 1133, Big Rapids, Michigan 49301, or by wire transfer to a bank designated by WOLVERINE. Any payment not made on or before the applicable due dates set forth in this Section 5.4.2 shall bear interest at the rate of 1% per month or the highest lawful rate, whichever is lower.

The period during which CONSUMERS must purchase such CAMPBELL 3 Unit Capability from such COOPERATIVE shall extend until the earliest of (a) the date on which such COOPERATIVE'S Electric Capability and Energy Entitlement in CAMPBELL 3 ceases and terminates pursuant to Section 4.2.1, (b) the fifth anniversary of the Commercial Operation Date of CAMPBELL 3, or (c) receipt by

CONSUMERS of written notice from such COOPERATIVE of its election to require CONSUMERS to repurchase from such COOPERATIVE the additional ownership interest which resulted from its additional investment under this Section 5.4.2. A COOPERATIVE which has invested additional funds under this Section 5.4.2 shall have the election to require CONSUMERS to repurchase the additional ownership interest resulting from such additional investment by giving written notice of such election to CONSUMERS not later than the fifth anniversary of the Commercial Operation Date of CAMPBELL 3. If such written notice is given within such five year period, CONSUMERS shall repurchase from such COOPERATIVE, and such COOPERATIVE shall sell to CONSUMERS, the portion of the COOPERATIVE'S ownership interest which resulted from the additional investment made by the COOPERATIVE under this Section 5.4.2, at a price equal to the original cost of such COOPERATIVE'S additional ownership interest in CAMPBELL 3 less related accumulated depreciation to the date of such transfer of ownership determined in accordance with the rates of depreciation approved for such COOPERATIVE by the Michigan Public Service Commission. Upon receipt of such payment, the COOPERATIVE shall execute such instruments as may be necessary to perfect the ownership interest to which CONSUMERS is restored hereunder, free and clear of all liens, charges and encumbrances attaching to or affecting such additional ownership interest during the period in which such COOPERATIVE held such additional ownership interest, including the lien of the indenture of such COOPERATIVE. If such written notice is not given within such five year period such COOPERATIVE shall retain the portion of its ownership interest which resulted from the additional investment made by the COOPERATIVE under this Section 5.4.2.

Throughout the period during which CONSUMERS must purchase such CAMPBELL 3 Unit Capability from such COOPERATIVE, the amount of such purchase shall be added to CONSUMERS' Electric Capability and Energy Entitlement and subtracted from such COOPERATIVE'S Electric Capability and Energy Entitlement.

5.4.3 Unilateral Delay by CONSUMERS.

In the event CONSUMERS unilaterally decides not to have CAMPBELL 3 in commercial operation by October 15, 1980 (as said scheduled Commercial Operation Date may be extended by all intervening events of force majeure) because of (a) the availability of more economical electric capability and energy to CONSUMERS from other sources, or (b) because CONSUMERS no longer requires any electric capability and energy from CAMPBELL 3, CONSUMERS shall, upon written request from either COOPERATIVE, and subject to appropriate regulatory approval to the extent required by law, sell to such COOPERATIVE, beginning with the scheduled Commercial

Operation Date, October 15, 1980, of CAMPBELL 3 (as said scheduled Commercial Operation Date may be extended by all intervening events of force majeure) an amount of electric capacity and energy determined in accordance with the formula below.

$$C_{c3} = \frac{C_c}{C_e} \times C_3$$

Where C_{c3} = Electric capacity in megawatts and associated energy to be sold by CONSUMERS to the COOPERATIVE. Such electric capacity and associated energy shall be delivered at no greater than 70% capacity factor during any calendar month.

C_c = Cost of Construction paid by the COOPERATIVE to CONSUMERS for CAMPBELL 3 up to time of CONSUMERS' unilateral decision to delay CAMPBELL 3.

C_3 = Expected Net Demonstrated Capability of CAMPBELL 3 (i.e., 791 MW).

C_e = CONSUMERS' estimate of total Cost of Construction required to construct CAMPBELL 3.

The rates to be charged monthly for such sale of electric capacity and energy to such COOPERATIVE shall be CONSUMERS' system average cost of electric capacity and energy, excluding CAMPBELL 3, as determined annually, or at such other intervals as CONSUMERS may elect, in the manner illustrated in Appendix F. Said rates shall be filed by CONSUMERS with the Federal Energy Regulatory Commission or any successor agency or department. CONSUMERS shall at all times have the right unilaterally to make application to the Federal Energy Regulatory Commission, or any successor agency or department, for a change in said rates under Section 205 of the Federal Power Act and pursuant to the Federal Energy Regulatory Commission's rules and regulations promulgated thereunder or under comparable statutes and regulations of a successor agency or department. Such COOPERATIVE shall have the right to protest the reasonableness of said rates and participate in any such proceedings; provided, however, that such COOPERATIVE may not contest the legality of any such unilateral application by CONSUMERS to the Federal Energy Regulatory Commission or any successor agency or department, on the basis that such unilateral application by CONSUMERS is prohibited by the terms of this Agreement. Unless cancelled sooner by mutual agreement of CONSUMERS and such COOPERATIVE, the sale of electric capacity and energy to such COOPERATIVE resulting from such unilateral delay of CAMPBELL 3 by CONSUMERS shall continue until the actual Commercial Operation Date of CAMPBELL 3. CONSUMERS shall save and hold the COOPERATIVES harmless from any increase in Cost of Construction of CAMPBELL 3, including AFUDC associated with the COOPERATIVES' 1.89% ownership interest, occasioned by CONSUMERS' unilateral delay for either of the reasons stated in (a) and (b) of the first sentence in the first paragraph of this Section 5.4.3.

In the event that such unilateral delay of CAMPBELL 3 extends for a period of five years from the time of CONSUMERS' decision resulting in such unilateral delay, each COOPERATIVE shall have the right to require CONSUMERS to repurchase such COOPERATIVE'S ownership interest in the property included in CAMPBELL 3 at a price equivalent to such COOPERATIVE'S total investment, including AFUDC, in the property included in CAMPBELL 3. Each COOPERATIVE shall have 30 days following the termination of said five-year period to notify CONSUMERS of its desire to exercise said right. CONSUMERS and each COOPERATIVE shall have a further 180 days from CONSUMERS' receipt of such notice from such COOPERATIVE to complete all arrangements necessary for and arising from the repurchase by CONSUMERS of such COOPERATIVE'S ownership interest in the property included in CAMPBELL 3. Upon completion of such arrangements by CONSUMERS and such COOPERATIVE, and concurrently with the payment by CONSUMERS to such COOPERATIVE of the price referred to in the first sentence of this paragraph, such COOPERATIVE shall execute all conveyances and other documents required to convey back its ownership interest in the property included in CAMPBELL 3 to CONSUMERS, free from all liens or other encumbrances, and this Agreement, the CAMPBELL 3 Back-Up Requirements Agreement and the CAMPBELL 3 Transmission Agreement shall be deemed to have expired as to such COOPERATIVE.

As used above in the first paragraph of this Section 5.4.3, the term "force majeure" shall mean, without limitation, the following: acts of God; strikes, lockouts or other industrial disturbances; acts of public enemies; orders, or absence of necessary orders and permits of any kind, from the government of the United States, or from the State of Michigan, or any of their departments, agencies or officials, or from any civil or military authority pertaining to CAMPBELL 3; insurrections; riots; delay in transportation; unforeseen soil conditions; equipment, material, supplies, labor or machinery shortages; epidemics; landslides; lightning; earthquakes; fire; hurricanes; tornadoes; storms; floods; washouts; drought; arrest; war; civil disturbances; explosions; breakage or accident to machinery, equipment, transmission lines, pipes or canals; partial or entire failure of utility service; breach of contract by any supplier, contractor, subcontractor, laborer or materialman, other than CONSUMERS; sabotage; injunction; blight; famine; blockage; quarantine; or any other similar or dissimilar cause or event not reasonably within the control of CONSUMERS.

5.5 Information.

CONSUMERS shall make all reasonable effort to inform the COOPERATIVES as to planning during the progress of construction and completion of CAMPBELL 3. Either COOPERATIVE may request, and CONSUMERS shall provide, additional information or reports concerning CAMPBELL 3, or this Agreement, as reasonably required by such COOPERATIVE. All costs of furnishing such additional information or reports shall be paid by the requesting COOPERATIVE.

ARTICLE 6

OPERATING ARRANGEMENTS

6.1 Authority for Operation and Managment.

CONSUMERS shall have sole authority, to be discharged in accordance with the provisions of this Agreement and consistent with the normal practices and procedures observed by CONSUMERS with respect to its other fossil fuel-fired steam electric generating units, to manage, control, maintain and operate CAMPBELL 3, and shall take all steps which it deems necessary or appropriate for that purpose.

6.2 Scheduling and Dispatching of Electric Generation.

CONSUMERS shall have sole authority for the hourly scheduling and dispatching of CAMPBELL 3 electric generation, in accordance with CONSUMERS' scheduling and dispatching practice.

In accordance with the next sentence of this paragraph, NORTHERN and WOLVERINE shall each request, for their own use, all or any part of their respective Electric Capability and Energy Entitlements in CAMPBELL 3 referred to in Section 6.3 (as such Electric Capability and Energy Entitlements may be modified pursuant to Sections 5.4.2, 6.6, 6.7, 9.8.2, 13.2, 13.3, 13.4 and 17.1); provided, that during periods when CAMPBELL 3 is being operated at minimum generation, the COOPERATIVES, unless otherwise agreed to by CONSUMERS, shall not request less than what their respective Electric Capability and Energy Entitlements in CAMPBELL 3 would have been had the net electric generating capability of CAMPBELL 3 and the electric energy associated therewith been restricted to such minimum generation of CAMPBELL 3. NORTHERN and WOLVERINE shall provide to CONSUMERS statements of their respective hourly generation requirements from CAMPBELL 3 for each day, such statements to be provided in a timely manner and by procedures approved by the Administrative Committee. CONSUMERS shall promptly notify the COOPERATIVES of any significant change in the net electric generating capability of CAMPBELL 3. As used in this paragraph, the term "*minimum generation*" means the net electric generating capability level below which CAMPBELL 3 cannot operate in a stable manner and must be shut down.

At any time NORTHERN or WOLVERINE, or both, are not requesting the maximum amount of electric generating capability available to them from CAMPBELL 3, CONSUMERS shall have the right to utilize, for its own use, all or any part of the electric energy associated with such unused electric generating capability. CONSUMERS shall pay NORTHERN or WOLVERINE, or both, as the case may require, for such electric energy utilized by it as aforesaid. The price to be paid by CONSUMERS for said electric energy shall be the average of (a) the fuel expense and energy-related operation and maintenance expenses incurred by NORTHERN or WOLVERINE, or both, as the case may be, for said electric energy generated by CAMPBELL 3 during the period that said electric energy is utilized by CONSUMERS, and (b) the estimated cost that CONSUMERS would have incurred had it obtained an equivalent amount of electric energy from other sources during such period.

CONSUMERS shall submit to the COOPERATIVES, as far in advance as practicable, schedules showing the expected time and duration of maintenance outages of CAMPBELL 3.

In the event, and only in the event, CONSUMERS voluntarily ceases to operate CAMPBELL 3 solely because of the availability of electric energy to CONSUMERS from other sources the average cost of which is projected to be lower than what the cost of electric energy generated by CAMPBELL 3 would be during the period of such cessation in operation, CONSUMERS shall make available to the COOPERATIVES replacement electric energy from such other sources during the period of such cessation in operation. The amount of such replacement electric energy to be made available to the COOPERATIVES during such period shall be the amount of electric energy requested by the COOPERATIVES during such period, but not in excess of the amount to which the COOPERATIVES would have been entitled during such period had the operation of CAMPBELL 3 not ceased. The cost of such replacement energy shall be the average of (a) the estimated cost that would have been incurred by the COOPERATIVES for electric energy generated by CAMPBELL 3 if CAMPBELL 3 were continued in operation during such period at the level at which it was operated at the time CONSUMERS voluntarily ceases to operate CAMPBELL 3, and (b) the cost incurred by CONSUMERS for such replacement electric energy obtained from such other sources during such period.

6.3 Electric Capability and Energy Entitlements.

Beginning with the Commercial Operation Date of CAMPBELL 3 and continuing until CAMPBELL 3 ceases to be used for the generation of electric energy, CONSUMERS, NORTHERN and WOLVERINE shall be entitled to 98.11%, 1.26% and 0.63%, respectively (as such percentages may be modified pursuant to Sections 5.4.2, 6.6, 6.7, 9.8.2, 13.2, 13.3, 13.4 and 17.1) of the net electric generating capability of CAMPBELL 3 and the electric energy associated therewith. The net electric generating capability of CAMPBELL 3, and the electric energy associated therewith, at any time shall be equal to the gross electric capability, and associated electric energy, of CAMPBELL 3 at that time less the electric energy utilized by CAMPBELL 3 for all processes, auxiliary equipment and systems used or useful in connection with start-up, operation, maintenance, control, supply or shutdown of CAMPBELL 3, including appropriate station service transformer losses. However, the net electric generating capability of CAMPBELL 3 shall not exceed the Normal Capability of CAMPBELL 3 except under criteria as may be established by the Administrative Committee.

6.4 Electric Capability and Energy Output to System.

The net electric capability and energy output of CAMPBELL 3 delivered to CONSUMERS' transmission system at any time shall be equal to the net electric generating capability of CAMPBELL 3 at that time, and the electric energy associated therewith, less the associated CAMPBELL 3 main power transformer losses and 345 kV transmission line losses between the CAMPBELL 3 main power transformers and the Campbell 345 kV Substation located approximately 0.9 mile easterly of CAMPBELL 3, said Campbell 345 kV Substation being the point of delivery of such capability and energy to CONSUMERS' transmission system.

6.5 <u>Test Electric Energy</u>.

Any net electric energy output from CAMPBELL 3 prior to the Commercial Operation Date of said unit shall be classified as test electric energy. CONSUMERS shall be entitled to 100% of all such test electric energy that is generated prior to the Closing. CONSUMERS, NORTHERN and WOLVERINE shall be entitled to 98.11%, 1.26% and 0.63%, respectively (as such percentages may be modified pursuant to Sections 5.4.2, 9.8.2, 13.2, 13.3, 13.4 or 17.1) of all such test electric energy that is generated on and after the Closing. CONSUMERS shall purchase the COOPERATIVES' share of such test electric energy which is generated by CAMPBELL 3 on any day at a price equal to the cost of the COOPERATIVES' share of such test electric energy on that day. Such price shall be reflected as a credit in the applicable invoice which is referred to in Section 3.5.1 which is furnished by CONSUMERS to the COOPERATIVES in the month following the month in which such test electric energy is generated.

6.6 <u>Electric Capability Not Needed By the COOPERATIVES</u>.

CONSUMERS shall have the obligation to purchase from each COOPERATIVE, and each COOPERATIVE shall have the obligation to sell to CONSUMERS, such COOPERATIVE'S Planned Excess Electric Capability as set forth in Sections 6.6.1 and 6.6.2 hereof, and CONSUMERS shall have the first right to purchase from each COOPERATIVE the Unplanned Excess Electric Capability of such COOPERATIVE as set forth in Section 6.7 hereof; provided, however, that if (a) NORTHERN'S Electric

Capability and Energy Entitlement in CAMPBELL 3 is increased above the level of 1.26% pursuant to Sections 5.4.2, 9.8.2, 13.2, 13.3 or 13.4, then the provisions of Sections 6.6.1 and 6.6.2 hereof shall be limited to said level of 1.26% in the case of NORTHERN, or (b) WOLVERINE'S Electric Capability and Energy Entitlement in CAMPBELL 3 is increased above the level of 0.63% pursuant to Sections 5.4.2, 9.8.2, 13.2, 13.3 or 13.4, then the provisions of Sections 6.6.1 and 6.6.2 hereof shall be limited to said level of 0.63% in the case of WOLVERINE.

6.6.1 COOPERATIVES' Planned Excess Electric Capability in CAMPBELL 3.

During the first 10 years of CAMPBELL 3's commercial operation, each COOPERATIVE shall be obligated to sell to CONSUMERS, and CONSUMERS shall be obligated to purchase from such COOPERATIVE, a declining fractional part of such COOPERATIVE'S Electric Capability and Energy Entitlement in CAMPBELL 3 in accordance with the following schedule:

Year of Commercial Operation	Fractional Part of NORTHERN'S 1.26% Electric Capability and Energy Entitlement in CAMPBELL 3 to be Purchased by CONSUMERS	Fractional Part of WOLVERINE'S 0.63% Electric Capability and Energy Entitlement in CAMPBELL 3 to be Purchased by CONSUMERS
1	9/10	4.5/5
2	8/10	4.0/5
3	7/10	3.5/5
4	6/10	3.0/5
5	5/10	2.5/5
6	4/10	2.0/5
7	3/10	1.5/5
8	2/10	1.0/5
9	1/10	0.5/5
10	0	0

For purposes of this Section 6.6.1, the first year of CAMPBELL 3's commercial operation shall mean the period beginning with the Commercial Operation Date of CAMPBELL 3 and ending with the last day of the calendar year in which the Commercial Operation Date of CAMPBELL 3 occurs; and the remaining 9 years of the first 10 years of CAMPBELL 3's commercial operation shall mean the 9 successive calendar years next following said first year. The amount of Planned Excess Electric Capability in CAMPBELL 3 purchased by CONSUMERS from each COOPERATIVE shall be added to CONSUMERS' Electric Capability and Energy Entitlement and subtracted from such COOPERATIVE'S Electric Capability and Energy Entitlement.

6.6.2 <u>CONSUMERS' Payment for COOPERATIVES' Planned Excess Electric Capability in CAMPBELL 3.</u>

CONSUMERS shall make monthly payments to each COOPERATIVE, beginning with the calendar month in which CAMPBELL 3 goes into commercial operation, for such COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3. Such payments shall be determined in accordance with the following formula and as illustrated in Appendix H hereto:

$$\text{Monthly Payment} = \frac{1}{12}\left[\frac{(F_c + F_p)}{2} \times D_p \times C_{cp} + A \times C_{cp}\right] + A_f$$

Where F_c = Annual fixed charge factor for CONSUMERS determined for each calendar year in which such monthly payments are to be made.

Such annual fixed charge factor expressed as a decimal shall include (a) overall rate of return on applicable net investment which is determined on the basis of (i) the imbedded cost of debt and preferred and preference stock, (ii) the rate of return on common equity on which CONSUMERS' wholesale for resale electric rates approved, or permitted to become effective in a final order, by the Federal Energy Regulatory Commission, or any successor agency or department, are based, and (iii) the capitalization ratios derived from Capitalization as shown in CONSUMERS' Annual Report to its stockholders with appropriate adjustment to such Capitalization for Current Obligations and Sinking Fund Requirement, and (b) applicable taxes, i.e., federal income tax, the income and interest portions of the Michigan Single Business Tax, or any other applicable tax not accounted for in this sentence. Such annual fixed charge factor for each calendar year in which such monthly payments are to be made shall be based on the year-end data for the immediately preceding calendar year.

F_p = The COOPERATIVE'S annual fixed charge factor expressed as a decimal shall include (a) financing cost associated with CAMPBELL 3 and (b) applicable taxes associated with CAMPBELL 3, i.e., federal income tax, if any, the income and interest portions of the Michigan Single Business Tax, or any other applicable tax not accounted for in this sentence or in A. Prior to the Second Closing, the term "financing cost associated with CAMPBELL 3", as used in (a) of the preceding sentence, shall mean the cost of short term debt associated with CAMPBELL 3; and on and after the Second Closing, said term "financing cost associated with CAMPBELL 3", as used in (a) of said preceding sentence, shall mean the weighted cost of long term debt associated with CAMPBELL 3. Except as otherwise provided in the next following three sentences, such annual fixed charge factor for each calendar year, in which such monthly payments are to be made, shall be based on the year-end data for the immediately preceding calendar year. During the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, such annual fixed charge factor shall be determined in each calendar month, for which such a monthly payment is to be made, based on the month-end data for the immediately preceding calendar month. For the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, in which such monthly payments are to be made, such annual fixed charge factor shall be based on data available as of the Second Closing. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then during the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, such annual fixed charge factor shall be determined in each calendar month, for which such a monthly payment is to be made, based on the month-end data for the immediately preceding calendar month.

D_p = Except as otherwise provided in the next following three sentences, D_p shall be the COOPERATIVE'S average net investment for the calendar year in which such monthly payments are to be made, including AFUDC, in its ownership interest in the property included in CAMPBELL 3, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory for CAMPBELL 3 for such calendar year. During the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, D_p shall be determined in each calendar month, for which such a monthly payment is to be made, and shall be the COOPERATIVE'S average net investment for such calendar month, including AFUDC, in its ownership interest in the property included in CAMPBELL 3, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory for CAMPBELL 3 for such calendar month. For the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, D_p shall be the COOPERATIVE'S average net investment for said period in which such monthly payments are to be made, including AFUDC, in its ownership interest in the property included in CAMPBELL 3, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory for CAMPBELL 3 for said period. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then during the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, D_p shall be determined in each month, for which such a payment is to be made, and shall be the COOPERATIVE'S average net investment for such calendar month, including AFUDC, in its ownership interest in the property included in CAMPBELL 3, plus the COOPERATIVE'S applicable working capital for materials and supplies and fuel inventory for CAMPBELL 3 for such calendar month.

C_{cp} = Fractional part of the COOPERATIVE'S Electric Capability and Energy Entitlement in CAMPBELL 3 which CONSUMERS is obligated to purchase.

A = Expenses incurred by the COOPERATIVE, for each calendar year in which such monthly payments are to be made, as a result of its investment in the property included in CAMPBELL 3. Such expenses incurred by the COOPERATIVE as a result of its investment in the property included in CAMPBELL 3 shall include (a) depreciation expense, including any retirement costs (as provided for in Section 20.2), as authorized by the Michigan Public Service Commission or any successor agency or department, (b) Operating Costs, (c) property taxes, (d) insurance, (e) liability expenses, if any, and (f) any other appropriate expense that may be incurred by the COOPERATIVE as a result of its investment in the property included in CAMPBELL 3.

A_f = Fuel expense incurred by the COOPERATIVE for the electric energy associated with the Planned Excess Electric Capability purchased by CONSUMERS in the month for which such payment is being made.

F_c, F_p, D_p, A and A_f may have to be estimated for purposes of applying the above formula. In the event that (a) the actual value of F_c for the calendar year in which such monthly payments are to be made, based on the year-end data for the immediately preceding calendar year, differs from the estimated value thereof, or (b) the actual value of F_p or D_p, for the calendar year or other period, as set forth in F_p or D_p, in which such monthly payments are to be made, differs from the estimated value thereof, or (c) the actual value of A, at any time during the calendar year in which such monthly payments are to be made, differs from the estimated value thereof, or (d) the actual value of A_f in any month in which such payments are to be made, differs from the estimated value thereof, then in any such event an adjustment shall be made for any overpayments or underpayments which result from such difference.

Unless a net invoice procedure is utilized pursuant to Section 6.11, payment by CONSUMERS of the monthly payment for each COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3, excepting the portion thereof represented by A_f, shall be made as follows:

(1) On or before the 15th day of each month, beginning with the month next preceding the month in which CAMPBELL 3 goes into commercial operation, the COOPERATIVE shall furnish CONSUMERS an invoice showing the payment, excepting the portion thereof represented by A_f, required for the following month. The first month's payment, excepting the portion thereof represented by A_f, required for such Planned Excess Electric Capability shall be adjusted to reflect the actual Commercial Operation Date of CAMPBELL 3. The payment for the month in which the Second Closing occurs, excepting the portion thereof represented by A_f, required for such Planned Excess Electric Capability shall be adjusted to reflect the actual date of the Second Closing. If the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then the payment for the month in which the COOPERA-

TIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate pursuant to Section 4.2.1, excepting the portion thereof represented by A_f, required for such Planned Excess Electric Capability shall be adjusted to reflect the actual date of such cessation and termination of the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3.

(2) Any adjustment resulting from the difference between the actual value of F_c from the estimated value thereof, as set forth in the second paragraph of this Section 6.6.2, shall be reflected in the invoice submitted in May of each calendar year in which such difference occurs.

Except as otherwise provided in the next following three sentences, any adjustment resulting from the difference between the actual value of F_p from the estimated value thereof, as set forth in the second paragraph of this Section 6.6.2, shall be reflected in the invoice submitted in May of each calendar year in which such difference occurs. If any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning with the Commercial Operation Date of CAMPBELL 3 and extending until the Second Closing, the adjustment for such difference shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred. If any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning with the Second Closing and extending through the end of the calendar year in which the Second Closing occurs, the adjustment for such difference shall be reflected in the invoice submitted in June of 1981. However, if the Second Closing does not occur on or before February 1, 1981, as provided in Section 4.2.1, then if any difference between the actual value of F_p from the estimated value thereof, as set forth in said second paragraph, occurs in the period beginning on February 1, 1981 and extending until the COOPERATIVES' Electric Capability and Energy Entitlements in CAMPBELL 3 cease and terminate as provided in Section 4.2.1, then the adjustment for such difference shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

Any adjustment resulting from the difference between the actual value of D_p or A from the estimated value thereof, as set forth in the second paragraph of this Section 6.6.2, shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

(3) These invoices shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 9th day of the following month or the first working day thereafter if the payment date falls on other than a working day.

Unless a net invoice procedure is utilized pursuant to Section 6.11, payment by CONSUMERS of the portion of the monthly payment for each COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3 which is represented by A_f shall be made as follows:

(1) On or before the 5th day of each month, beginning with the month in which CAMPBELL 3 goes into commercial operation, the COOPERATIVE shall furnish CONSUMERS an invoice showing the payment required for A_f for such month. The first month's payment required for A_f shall be adjusted to reflect the actual Commercial Operation Date of CAMPBELL 3.

(2) Any adjustment resulting from the difference between the actual value of A_f from the estimated value thereof, as set forth in the second paragraph of this Section 6.6.2, shall be reflected in the invoice submitted for the third month following the month in which the actual costs giving rise to such difference were incurred.

(3) These invoices shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 25th day of such month or the first working day thereafter if the payment date falls on other than a working day.

All payments made to NORTHERN under this Section 6.6.2 shall be made in immediately available funds payable to Northern Michigan Electric Cooperative, Inc. and shall be sent to Northern Michigan Electric Cooperative, Inc., Attention: General Manager, Post Office Box 138, Boyne City, Michigan 49712, or by wire transfer to a bank designated by NORTHERN. All payments made to WOLVERINE under this Section 6.6.2 shall be made in immediately available funds payable to Wolverine Electric Cooperative, Inc. and shall be sent to Wolverine Electric Cooperative, Inc., Attention: General Manager, Post Office Box 1133, Big Rapids, Michigan 49301, or by wire transfer to a bank designated by WOLVERINE. Any payment not made on or before the applicable due dates set forth in this Section 6.6.2 shall bear interest at the rate of 1% per month or the highest lawful rate, whichever is lower.

6.7 <u>COOPERATIVES' Unplanned Excess Electric Capability in CAMPBELL 3</u>

If at any time either COOPERATIVE determines that any amount of its Electric Capability and Energy Entitlement available to it from CAMPBELL 3, after taking into account such COOPERATIVE'S Planned Excess Electric Capability purchased by CONSUMERS pursuant to Sections 6.6.1 and 6.6.2, will not be required by it to supply its own load for any period of one or more weeks, CONSUMERS shall have the first right to purchase all or any part of such Unplanned Excess Electric Capability from such COOPERATIVE at rates determined using the principles set forth in Section 6.6.2 hereof, or at such lower rates as may be offered by such COOPERATIVE to the other COOPERATIVE or to third parties. If CONSUMERS purchases all or any part of such COOPERATIVE'S Unplanned Excess Electric Capability, the amount of such purchase during such period shall be added to CONSUMERS' Electric Capability and Energy Entitlement and subtracted from such COOPERATIVE'S Electric Capability and Energy Entitlement. As used in this paragraph, the term "week" means any period of seven consecutive days.

6.8 Operations Management.

CONSUMERS, as sole manager of CAMPBELL 3, shall take all steps which it deems necessary or appropriate for the operation and maintenance of CAMPBELL 3, which may include the following:

6.8.1 Execute, administer, perform and enforce (including any renegotiation and settlement) all contracts, contractual obligations and arrangements for Operating Work and Capital Improvements, including, without limitation, any and all warranties on equipment, facilities, materials and services furnished pursuant to any such contracts.

6.8.2 Make all decisions with respect to Capital Improvements, including the replacement, modification, renewal, disposal and salvaging of any part of the property included in CAMPBELL 3.

6.8.3 Comply with (a) any and all laws applicable to the performance of Operating Work and Capital Improvements for CAMPBELL 3, including, without limitation, all applicable laws, rules and regulations for protection of the environment and all applicable provisions of any worker's compensation laws, and (b) the terms and conditions of any contract, permit or license relating to CAMPBELL 3.

6.8.4 Purchase and procure, through and from any source it may select, the equipment, apparatus, machinery, tools, services, materials and supplies and emergency spare parts necessary for the performance of Operating Work and Capital Improvements.

6.8.5 Expend funds in accordance with the terms and conditions of this Agreement.

6.8.6 In accordance with the Uniform System of Accounts, keep and maintain such records of monies received and expended, obligations incurred, credits accrued, the conduct of Operating Work, making of Capital Improvements, and of contracts entered into in the performance of Operating Work or making of Capital Improvements, as may be necessary or useful in carrying out this Agreement or required to permit an audit of the Operating Work and Capital

Improvements relating to CAMPBELL 3, and make such records available to the COOPERATIVES for inspection.

6.8.7 Not permit any liens to remain in effect unsatisfied against CAMPBELL 3, other than the liens permitted under this Agreement, liens for taxes and assessments not yet delinquent, and liens for labor and material not yet perfected.

6.8.8 Arrange for the placement and maintenance of Operating Insurance.

6.8.9 Assist any insurer in the investigation of any loss or claim covered by Operating Insurance, and adjust and settle such loss or claim with such insurer.

6.8.10 Present and prosecute claims against insurers and indemnitors providing Operating Insurance or indemnities with respect to any loss of or damage to any property of CAMPBELL 3 or liability of CONSUMERS or the COOPERATIVES to third parties, and to the extent that such loss, damage or liability is not covered by Operating Insurance or by any indemnity agreement, present and prosecute claims therefor against any parties who may be liable therefor.

6.8.11 Investigate, adjust, defend and settle claims by third parties against either of the COOPERATIVES or both and CONSUMERS, arising out of or attributable to Operating Work or Capital Improvements, or the past or future performance or nonperformance of the obligations and duties of either the COOPERATIVES or CONSUMERS under or pursuant to this Agreement, including but not limited to any claim resulting from death or injury to persons or damage to property, when such claims are not covered by valid and collectible Operating Insurance carried by CONSUMERS or either NORTHERN or WOLVERINE; and, whenever and to the extent reasonable, present and prosecute claims against any third party, including insurers, for any costs, losses and damages incurred in connection with such claims.

6.8.12 In the event of an operating curtailment or emergency, take such action as CONSUMERS, in its sole discretion, may deem prudent or necessary to terminate the operating curtailment or emergency, so as to (1) preserve and maintain the safety, integrity and operability of CAMPBELL 3, (2) protect the health and safety of the public, and (3) minimize any adverse environmental effects.

6.8.13 As promptly as practicable after the end of each month, CONSUMERS shall render to the COOPERATIVES a statement setting forth appropriate operating data as may be needed for reports and records.

6.9 Reactive Power.

Unless otherwise mutually agreed, the COOPERATIVES shall provide the reactive power requirements of their own electric systems.

6.10 Mutual Assistance.

The COOPERATIVES shall lend, and be properly reimbursed for, all necessary and available assistance as may be requested by CONSUMERS in the performance of Operating Work. The COOPERATIVES shall advise CONSUMERS immediately of any incident or litigation affecting their further participation in this Agreement.

6.11 Net Invoice Procedure.

The COOPERATIVES may desire that a net invoice procedure be utilized in lieu of their furnishing invoices to CONSUMERS pursuant to Sections 5.4.2 and 6.6.2 hereof. If requested by the COOPERATIVES, CONSUMERS shall, to the extent that it deems practicable, reflect any amount that it owes to the COOPERATIVES pursuant to said Sections 5.4.2 and 6.6.2, as a credit in the appropriate invoice which it is to furnish to the COOPERATIVES pursuant to Sections 7.3 or 12.4; provided, that if the amount owed by CONSUMERS to either of the COOPERATIVES is in excess of the amount owed by such COOPERATIVE to CONSUMERS, as set forth in such net invoice, CONSUMERS shall pay such excess to such COOPERATIVE in accordance with (1), (2) and (3) below:

(1) If such excess is related to the monthly payment for (a) the portion of such COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3 which is represented by A_f, or (b) the portion of such COOPERATIVE'S CAMPBELL 3 Unit Capability which is represented by A_f, such excess shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 25th day of such month or the first working day thereafter if the payment date falls on other than a working day. If such excess is related to the monthly payment for

(a) such COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3, excepting the portion thereof represented by A_f, or (b) such COOPERATIVE'S CAMPBELL 3 Unit Capability, excepting the portion thereof represented by A_f, such excess shall be paid by CONSUMERS so that the COOPERATIVE will receive the funds by the 9th day of the following month or the first working day thereafter if the payment date falls on other than a working day.

(2) All payments made to NORTHERN shall be made in immediately available funds payable to Northern Michigan Electric Cooperative, Inc. and shall be sent to Northern Michigan Electric Cooperative, Inc., Attention: General Manager, Post Office Box 138, Boyne City, Michigan 49712, or by wire transfer to a bank designated by NORTHERN. All payments made to WOLVERINE shall be made in immediately available funds payable to Wolverine Electric Cooperative, Inc. and shall be sent to Wolverine Electric Cooperative, Inc., Attention: General Manager, Post Office Box 1133, Big Rapids, Michigan 49301, or by wire transfer to a bank designated by WOLVERINE.

(3) Any payment not made on or before the due dates set forth in (1) above shall bear interest at the rate of 1% per month or the highest lawful rate, whichever is lower.

CONSUMERS' preparation of such net invoices shall be contingent on the COOPERATIVES' furnishing, in a timely manner and by procedures acceptable to CONSUMERS, all information and data required from the COOPERATIVES in order for CONSUMERS to prepare such net invoices.

6.12 Records of COOPERATIVES.

The COOPERATIVES, in accordance with the uniform system of accounts applicable to them, shall keep and maintain such records as may be necessary or useful in carrying out this Agreement or required to permit an audit of the values of F_p, C, A and A_f of Section 5.4.2 and the values of F_p, D_p, A and A_f of Section 6.6.2, and make such records available to CONSUMERS for inspection.

ARTICLE 7

OPERATING COSTS OF CAMPBELL 3

7.1 Operating Costs of CAMPBELL 3.

For purposes of this Agreement, Operating Costs of CAMPBELL 3 shall mean the total of (a) the operation and maintenance expenses and associated taxes, other than income taxes, of CAMPBELL 3, and (b) the portion of administrative and general expenses applicable to the system-wide electric operations of CONSUMERS which is allocable to CAMPBELL 3. All Operating Costs of CAMPBELL 3 shall be properly recordable in accordance with the instructions and in appropriate accounts as set forth in the Uniform System of Accounts. The operation and maintenance expenses and associated taxes, other than income taxes, of CAMPBELL 3 shall include production expenses (excluding fuel expenses), production supervision and engineering (including an appropriate portion of applicable general office supervision and engineering, which general office supervision and engineering is not included in administrative and general expense accounts), employee pensions and benefits, and payroll, sales and use taxes. For purposes of this Agreement, (a) insurance costs; (b) liability payments, costs, expenses or obligations; (c) taxes other than payroll, sales and use taxes; and (d) fuel costs; shall not be treated as a part of the operation and maintenance expenses and associated taxes, other than income taxes, of CAMPBELL 3. It is understood and agreed that (a) insurance costs shall be shared by the PARTIES as provided in Article 11, (b) liability payments, costs, expenses or obligations shall be shared by the PARTIES as provided in Article 15, (c) taxes other than payroll, sales and use taxes shall be shared by the PARTIES as provided in Article 10, and (d) fuel costs shall be shared by the PARTIES as provided in Article 12. The portion of administrative and general expenses applicable to the system-wide electric operations of CONSUMERS which is allocable to CAMPBELL 3 shall be determined through use of a percentage factor applied to the operation and maintenance expenses of CAMPBELL 3. The percentage factor to be used shall be equal to the ratio (expressed as a percentage) that (a) the product of (i) the ratio that CONSUMERS' total electric sales in kilowatthours less CONSUMERS' electric sales in kilowatthours in Pontiac bears to CONSUMERS' total electric sales in kilowatthours, and (ii) the total administrative and general expenses applicable to the system-wide electric operations of CONSUMERS which are included in Accounts 920-932 (after being reduced by the cost of insurance and liability payments which are included in Account 924 and by the pension and benefit costs associated with direct labor which are included in Account 926) bears to (b) all other electric operation and maintenance expenses applicable to the system-wide electric operations of CONSUMERS which are included in Accounts 500-916, of the Uniform System of Accounts, except for fuel, purchased power and interchange expenses.

7.2 Sharing of Operating Costs of CAMPBELL 3.

All Operating Costs of CAMPBELL 3 shall be shared by CONSUMERS and the COOPERATIVES in proportion to their respective percentage ownership interests in CAMPBELL 3.

7.3 Payment.

Payment by the COOPERATIVES of their share of Operating Costs of CAMPBELL 3; Capital Improvements; insurance costs; liability payments, costs, expenses or obligations; taxes other than income taxes and those taxes included in Operating Costs of CAMPBELL 3; and retirement costs; shall be made as follows:

7.3.1 On or before the 15th day of each month, beginning with the month next preceding the month in which CAMPBELL 3 goes into commercial operation, CONSUMERS shall furnish the COOPERATIVES an invoice showing the current estimate of payments, and the COOPERATIVES' share thereof, which CONSUMERS expects to make the following month in regard to Operating Costs of CAMPBELL 3; Capital Improvements; insurance costs; liability payments, costs, expenses or obligations; taxes other than income taxes and those taxes included in Operating Costs of CAMPBELL 3; and retirement costs.

7.3.2 These invoices shall be paid by the COOPERATIVES so that CONSUMERS will receive the funds by the 9th day of the following month or the first working day thereafter if the payment date falls on other than a working day.

7.3.3 Adjustments for the difference between estimated payments and actual costs shall be made on the invoice submitted for the third month following the month in which such costs were incurred.

7.3.4 All payments shall be made in immediately available funds payable to Consumers Power Company and shall be sent to Consumers Power Company, Attention: Treasurer, 212 West Michigan Avenue, Jackson, Michigan 49201, or by wire transfer to a bank designated by CONSUMERS.

7.3.5 Any payment not made on or before the due dates set forth in Section 7.3.2 shall constitute an act of default under Section 17.1 hereof.

7.4 Estimates.

After the Commercial Operation Date of CAMPBELL 3, estimates of monthly Operating Costs of CAMPBELL 3 for the immediate calendar year and each calendar year thereafter shall be prepared by CONSUMERS and submitted to the COOPERATIVES prior to the beginning of such calendar year.

7.5 Retirement - Property.

CONSUMERS shall have sole authority in decisions regarding the retirement from service of any and all property included in CAMPBELL 3. Cost of removal and salvage credits, if any, shall be shared by the PARTIES in proportion to their respective percentage ownership interests in CAMPBELL 3.

ARTICLE 8

POLLUTION CONTROL FACILITIES

8.1 Either CONSUMERS or NORTHERN or WOLVERINE shall have the right to enter into any arrangement, solely on its own behalf, for the purpose of financing its undivided ownership interest in pollution control facilities to be used for purposes of CAMPBELL 3 through the issuance by the County of Ottawa, the State of Michigan, or any other appropriate political body, agency or subdivision within the State of Michigan of pollution control revenue bonds, the interest on which is intended to be exempt from federal income taxes.

ARTICLE 9

GENERAL CONDITIONS

9.1 Cooperation.

CONSUMERS, NORTHERN and WOLVERINE shall cooperate with each other in all activities relating to CAMPBELL 3, including, without limitation, the filing of applications for authorizations, permits or licenses and the execution of such other documents as may be reasonably necessary to carry out the provisions of this Agreement. Without CONSUMERS' written consent, the COOPERATIVES shall not incur any obligation which would or could obligate CONSUMERS to any third party.

9.2 Approvals.

The PARTIES shall use their best efforts to obtain as quickly as possible all requisite governmental and regulatory approvals of the consummation of the transactions contemplated herein.

9.3 Access.

Official representatives of NORTHERN and WOLVERINE and their designees shall have the right, upon sufficient advance notice to CONSUMERS to insure efficient and safe construction and operation of CAMPBELL 3, to enter upon the CAMPBELL 3 SITE (and upon those portions of the CAMPBELL PLANT SITE on which any facilities included in CAMPBELL 3 are located) subject to the rules and regulations of governmental regulatory bodies having jurisdiction thereof, and subject to all safety, insurance and industrial security requirements.

9.4 Conditions Precedent to the Closing.

The fulfillment, prior to or at the Closing, of each and every condition as specifically set forth in Sections 9.4.1 through 9.4.4 below (or the waiver in writing of such condition by CONSUMERS) is a prerequisite to the Closing. Further, the fulfillment, prior to or at the Closing, of each and every condition as specifically set forth in Sections 9.4.5 through 9.4.8 below (or the waiver in writing of such condition by NORTHERN and WOLVERINE) is a prerequisite to the Closing. In addition, the fulfillment, prior to or at the Closing, of each and every condition as specifically set forth in Sections 9.4.9 through 9.4.12 below (or the waiver in writing of such condition by each of the PARTIES) is a prerequisite to the Closing.

9.4.1 CONSUMERS shall not have discovered any material error, misstatement or omission in the representations and warranties made by NORTHERN and WOLVERINE in this Agreement.

9.4.2 NORTHERN'S and WOLVERINE'S representations and warranties contained in this Agreement shall be deemed to have been made again at and as of the time of the Closing and shall then be true in all material respects; NORTHERN and WOLVERINE shall have performed and complied with all agreements, covenants and conditions required by this Agreement to be performed or complied with by them prior to or at the Closing; CONSUMERS shall have been furnished with certificates signed by the principal officers of both NORTHERN and WOLVERINE, dated the date of the Closing, certifying in form and substance satisfactory to CONSUMERS to the fulfillment of the foregoing conditions and to the further effect that there are no actions, suits or proceedings pending or, to such officer's knowledge, threatened against or affecting NORTHERN or WOLVERINE, as the case may be, before any court or administrative body or agency which might materially adversely affect the ability of

NORTHERN or WOLVERINE, as the case may be, to perform its obligations under this Agreement.

9.4.3 CONSUMERS shall have been furnished with opinions of counsel for NORTHERN and WOLVERINE, in form and substance satisfactory to CONSUMERS, dated the date of the Closing, to the effect that:

(a) NORTHERN or WOLVERINE, as the case may be, is a corporation duly organized and validly existing in good standing under the laws of the State of Michigan and has the corporate power and authority to carry on its business as presently conducted and to enter into and perform its obligations under this Agreement and the Campbell 3 Back-Up Requirements Agreement;

(b) The execution, delivery and performance by NORTHERN or WOLVERINE, as the case may be, of this Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly authorized by all necessary corporate action on the part of NORTHERN or WOLVERINE, as the case may be, do not contravene any law, or any governmental rule, regulation or order, applicable to NORTHERN or WOLVERINE, as the case may be, or its properties, or the Articles of Incorporation or By-Laws of NORTHERN or WOLVERINE, as the case may be, and do not and will not contravene the provisions of, or constitute a default under, any indenture, mortgage, contract or other instrument to which NORTHERN or WOLVERINE, as the case may be, is a party or by which NORTHERN or WOLVERINE, as the case may be, is bound;

(c) This Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly executed and delivered by NORTHERN or WOLVERINE, as the case may be, and constitute the legal, valid and binding obligations of NORTHERN or WOLVERINE, as the case may be, enforceable in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, reorganization or similar laws at the time in effect;

(d) There are no actions, suits or proceedings pending or, to such counsel's knowledge, threatened against or affecting NORTHERN or WOLVERINE, as the case may be, before any court or administrative body or agency which might materially adversely affect the ability of NORTHERN or WOLVERINE, as the case may be, to perform its obligations under this Agreement; and

(e) Any consent or approval of, giving of notice to, registration with or taking of any other action by, any state, federal or other governmental commission, agency or regulatory authority, in connection with the execution, delivery and performance of this Agreement and the Campbell 3 Back-Up Requirements Agreement required to be obtained by NORTHERN or

WOLVERINE, as the case may be, on or before the Closing has been obtained.

9.4.4 The deposit on the purchase price required to be paid by NORTHERN and WOLVERINE to CONSUMERS at the Closing shall be in immediately available funds.

9.4.5 NORTHERN and WOLVERINE shall not have discovered any material error, misstatement or omission in the representations and warranties made by CONSUMERS in this Agreement.

9.4.6 CONSUMERS' representations and warranties contained in this Agreement shall be deemed to have been made again at and as of the time of the Closing and shall then be true in all material respects; CONSUMERS shall have performed and complied with all agreements, covenants and conditions required by this Agreement to be performed or complied with by it prior to or at the Closing and NORTHERN and WOLVERINE shall have been furnished with a certificate of the President or a Vice President of CONSUMERS, dated the date of the Closing, certifying in form and substance satisfactory to NORTHERN and WOLVERINE, to the fulfillment of the foregoing conditions and to the further effect that there are no actions, suits or proceedings pending or, to such officer's knowledge, threatened against or affecting CONSUMERS before any court or administrative body or agency which might materially adversely affect the ability of CONSUMERS to perform its obligations under this Agreement.

9.4.7 NORTHERN and WOLVERINE shall have been furnished with opinions of counsel for CONSUMERS, in form and substance satisfactory to NORTHERN and WOLVERINE, dated the date of the Closing, to the effect that:

(a) CONSUMERS is a corporation duly organized and validly existing in good standing under the laws of the State of Michigan and has the corporate power and authority to carry on its business as presently conducted and to enter into and perform its obligations under this Agreement and the Campbell 3 Back-Up Requirements Agreement;

(b) The execution, delivery and performance by CONSUMERS of this Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly authorized by all necessary corporate action on the part of CONSUMERS, do not contravene any law, or any governmental rule, regulation or order applicable to CONSUMERS or its properties, or the Articles of Incorporation or By-Laws of CONSUMERS and do not and will not contravene the provisions of, or constitute a default under, any indenture, mortgage, contract or other instrument to which CONSUMERS is a party or by which CONSUMERS is bound;

(c) This Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly executed and delivered by CONSUMERS and constitute the legal, valid and binding obligations of CONSUMERS enforceable in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, reorganization or similar laws at the time in effect;

(d) There are no actions, suits or proceedings pending or, to such counsel's knowledge, threatened against or affecting CONSUMERS before any court or administrative body or agency which might materially adversely affect the ability of CONSUMERS to perform its obligations under this Agreement; and

(e) Any consent or approval of, giving of notice to, registration with or taking of any other action by, any state, federal or other governmental commission, agency or regulatory authority, in connection with the execution, delivery and performance of this Agreement and the Campbell 3 Back-Up Requirements Agreement required to be obtained by CONSUMERS on or before the Closing has been obtained.

9.4.8 National Rural Utilities Cooperative Finance Corporation (CFC) shall have been furnished with an opinion of counsel for CONSUMERS, in form and substance satisfactory to CFC, dated the date of the Closing, to the effect that:

(a) CONSUMERS is a corporation duly organized and validly existing in good standing under the laws of the State of Michigan and has the corporate power and authority to carry on its business as presently conducted and to enter into and perform its obligations under this Agreement;

(b) The execution, delivery and performance by CONSUMERS of this Agreement has been duly authorized by all necessary corporate action on the part of CONSUMERS, do not contravene any law, or any governmental rule, regulation or order applicable to CONSUMERS or its properties, or the Articles of Incorporation or By-Laws of CONSUMERS and does not and will not contravene the provisions of, or constitute a default under, any indenture, mortgage, contract or other instrument to which CONSUMERS is a party or by which CONSUMERS is bound;

(c) This Agreement has been duly executed and delivered by CONSUMERS and constitutes the legal, valid and binding obligations of CONSUMERS enforceable in accordance with its terms, except as limited by applicable bankruptcy, insolvency, reorganization or similar laws at the time in effect;

(d) There are no actions, suits or proceedings pending or, to such counsel's knowledge, threatened against or affecting CONSUMERS before any court or administrative body or agency which might materially adversely affect the ability of CONSUMERS to perform its obligations under this Agreement; and

(e) Any consent or approval of, giving of notice to, registration with or taking of any other action by, any state, federal or other governmental commission, agency or regulatory authority, in connection with the execution, delivery and performance of this Agreement required to be obtained by CONSUMERS on or before the Closing has been obtained.

9.4.9 All governmental and regulatory approvals of the execution, delivery and performance of this Agreement required to be obtained by CONSUMERS and NORTHERN and WOLVERINE on or before the Closing shall have been obtained.

9.4.10 NORTHERN shall have made arrangements for interim short-term financing obtained from National Rural Utilities Cooperative Finance Corporation (CFC) in an amount of at least Eight Million, Five Hundred Thousand Dollars ($8,500,000) for financing the payments which NORTHERN is obligated to make under Article 3 of this Agreement; and WOLVERINE shall have made arrangements for interim short-term financing obtained from CFC in an amount of at least Four Million, Two Hundred Fifty Thousand Dollars ($4,250,000) for financing the payments which WOLVERINE is obligated to make under said Article 3.

9.4.11 CONSUMERS and NORTHERN and WOLVERINE shall have executed and delivered the Campbell 3 Back-Up Requirements Agreement and the Campbell 3 Transmission Agreement concurrently herewith.

9.4.12 The Administrator of the Rural Electrification Administration shall have approved in writing this Agreement and the Campbell 3 Back-Up Requirements Agreement.

9.5 <u>Conditions Precedent to the Second Closing</u>.

The fulfillment, prior to or at the Second Closing, of each and every condition as specifically set forth in Sections 9.5.1 through 9.5.3 below (or the waiver in writing of such condition by CONSUMERS) is a prerequisite to the Second Closing. Further, the fulfillment, prior to or at the Second Closing, of each and every condition as specifically set forth in Sections 9.5.4 through 9.5.6 below (or the waiver in writing of such condition by NORTHERN and WOLVERINE) is a prerequisite to the Second Closing. In addition, the fulfillment, prior to or at the Second Closing, of each and every condition as specifically set forth in Sections 9.5.7 through 9.5.9 below (or the waiver in writing of such condition by each of the PARTIES) is a prerequisite to the Second Closing.

9.5.1 CONSUMERS shall not have discovered any material error, misstatement or omission in the representations and warranties made by NORTHERN and WOLVERINE in this Agreement.

9.5.2 NORTHERN'S and WOLVERINE'S representations and warranties contained in this Agreement shall be deemed to have been made again at and as of the time of the Second Closing and shall then be true in all material respects; NORTHERN and WOLVERINE shall have performed and complied with all agreements, covenants and conditions required by this Agreement to be performed or complied with by them prior to or at the Second Closing; CONSUMERS shall have been furnished with certificates signed by the principal officers of both NORTHERN and WOLVERINE, dated the date of the Second Closing, certifying in form and substance satisfactory to CONSUMERS to the fulfillment of the foregoing conditions and to the further effect that there are no actions, suits or proceedings pending or, to such officer's knowledge, threatened against or affecting NORTHERN or WOLVERINE, as the case may be, before any court or administrative body or agency which might materially adversely affect the ability of NORTHERN or WOLVERINE, as the case may be, to perform its obligations under this Agreement.

9.5.3 CONSUMERS shall have been furnished with opinions of counsel for NORTHERN and WOLVERINE, in form and substance satisfactory to CONSUMERS, dated the date of the Second Closing, to the effect that:

(a) NORTHERN or WOLVERINE, as the case may be, is a corporation duly organized and validly existing in good standing under the laws of the State of Michigan and has the corporate power and authority to carry on its business as presently conducted and to enter into and perform its obligations under this Agreement and the Campbell 3 Back-Up Requirements Agreement;

(b) The execution, delivery and performance by NORTHERN or WOLVERINE, as the case may be, of this Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly authorized by all necessary corporate action on the part of NORTHERN or WOLVERINE, as the case may be, do not contravene any law, or any governmental rule, regulation or order, applicable to NORTHERN or WOLVERINE, as the case may be, or its properties, or the Articles of Incorporation or By-Laws of NORTHERN or WOLVERINE, as the case may be, and do not and will not contravene the provisions of, or constitute a default under, any indenture, mortgage, contract or other instrument to which NORTHERN or WOLVERINE, as the case may be, is a party or by which NORTHERN or WOLVERINE, as the case may be, is bound;

(c) This Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly executed and delivered by NORTHERN or WOLVERINE, as the case may be, and constitute the legal, valid and binding obligations of NORTHERN or WOLVERINE, as the case may be, enforceable in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, reorganization or similar laws at the time in effect;

(d) There are no actions, suits or proceedings pending or, to such counsel's knowledge, threatened against or affecting NORTHERN or WOLVERINE, as the case may be, before any court or administrative body or agency which might materially adversely affect the ability of NORTHERN or WOLVERINE, as the case may be, to perform its obligations under this Agreement; and

(e) Any consent or approval of, giving of notice to, registration with or taking of any other action by, any state, federal or other governmental commission, agency or regulatory authority, in connection with the execution, delivery and performance of this Agreement and the Campbell 3 Back-Up Requirements Agreement required to be obtained by NORTHERN or WOLVERINE, as the case may be, on or before the Second Closing has been obtained.

9.5.4 NORTHERN and WOLVERINE shall not have discovered any material error, misstatement or omission in the representations and warranties made by CONSUMERS in this Agreement.

9.5.5 CONSUMERS' representations and warranties contained in this Agreement shall be deemed to have been made again at and as of the time of the Second Closing and shall then be true in all material respects; CONSUMERS shall have performed and complied with all agreements, covenants and conditions required by this Agreement to be performed or complied with by it prior to or at the Second Closing and NORTHERN and WOLVERINE shall have been furnished with a certificate of the President or a Vice President of CONSUMERS, dated the date of the Second Closing, certifying in form and substance satisfactory to NORTHERN and WOLVERINE, to the fulfillment of the foregoing conditions and to the further effect that there are no actions, suits or proceedings pending or, to such officer's knowledge, threatened against or affecting CONSUMERS before any court or administrative body or agency which might materially adversely affect the ability of CONSUMERS to perform its obligations under this Agreement.

9.5.6 NORTHERN and WOLVERINE shall have been furnished with opinions of counsel for CONSUMERS, in form and substance satisfactory to NORTHERN and WOLVERINE, dated the date of the Second Closing, to the effect that:

(a) CONSUMERS is a corporation duly organized and validly existing in good standing under the laws of the State of Michigan and has the corporate power and authority to carry on its business as presently conducted and to enter into and perform its obligations under this Agreement and the Campbell 3 Back-Up Requirements Agreement;

(b) The execution, delivery and performance by CONSUMERS of this Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly authorized by all necessary corporate action on the part of CONSUMERS, do not contravene any law, or any governmental rule, regulation or order applicable to CONSUMERS or its properties, or the Articles of Incorporation or By-Laws of CONSUMERS and do not and will not contravene the provisions of, or constitute a default under, any indenture, mortgage, contract or other instrument to which CONSUMERS is a party or by which CONSUMERS is bound;

(c) This Agreement and the Campbell 3 Back-Up Requirements Agreement have been duly executed and delivered by CONSUMERS and constitute the legal, valid and binding obligations of CONSUMERS enforceable in accordance with their respective terms, except as limited by applicable bankruptcy, insolvency, reorganization or similar laws at the time in effect;

(d) The Covenant Deeds and Bills of Sale executed by CONSUMERS in connection with the Second Closing have been duly authorized, executed and delivered by CONSUMERS and are effective to vest in NORTHERN and WOLVERINE all of the title of CONSUMERS in and to a 1.26% undivided ownership interest in the case of NORTHERN, and a 0.63% undivided ownership interest in the case of WOLVERINE, in the property included in CAMPBELL 3 which is existing and identified as of the Conveyance Date, free and clear of the lien of CONSUMERS' indenture (as defined in Section 2.3 hereof);

(e) There are no actions, suits or proceedings pending or, to such counsel's knowledge, threatened against or affecting CONSUMERS before any court or administrative body or agency which might materially adversely affect the ability of CONSUMERS to perform its obligations under this Agreement; and

(f) Any consent or approval of, giving of notice to, registration with or taking of any other action by, any state, federal or other governmental commission, agency or regulatory authority, in connection with the execution, delivery and performance of this Agreement and the Campbell 3 Back-Up Requirements Agreement required to be obtained by CONSUMERS on or before the Second Closing has been obtained.

9.5.7 All governmental and regulatory approvals of the execution, delivery and performance of this Agreement required to be obtained by CONSUMERS and NORTHERN and WOLVERINE on or before the Second Closing shall have been obtained.

9.5.8 There shall be in effect (a) a loan contract and a Rural Electrification Administration loan guarantee providing for a loan to NORTHERN of at least Eight Million, Five Hundred Thousand Dollars ($8,500,000) for financing its undivided ownership interest in the property included in CAMPBELL 3, and the conditions precedent to the advance of funds, with respect to such financing, set forth in such loan contract and such loan guarantee shall have been satisfied, and (b) a loan contract and a Rural Electrification Administration loan guarantee providing for a loan to WOLVERINE of at least Four Million, Two Hundred Fifty Thousand Dollars ($4,250,000) for financing its undivided ownership interest in the property included in CAMPBELL 3, and the conditions precedent to the advance of funds, with respect to such financing, set forth in such loan contract and such loan guarantee shall have been satisfied.

9.5.9 CONSUMERS shall have obtained the releases by Citibank, N.A. (formerly First National City Bank, successor by merger to First National City Trust Company, formerly City Bank Farmers Trust Company) as Trustee under CONSUMERS' indenture dated as of September 1, 1945, as amended and supplemented, of the ownership interest in the property included in CAMPBELL 3 to be conveyed to NORTHERN and WOLVERINE hereunder at the Second Closing from the lien of such indenture.

9.6 Amendments.

This Agreement may be amended only by a written instrument duly executed by all of the PARTIES. Further, no amendment of this Agreement shall become effective until approved by the Administrator of the Rural Electrification Administration.

9.7 "AS IS" SALE.

THE COOPERATIVES' OWNERSHIP INTERESTS IN THE PROPERTY INCLUDED IN CAMPBELL 3 ARE TO BE SOLD "AS IS" AND "WHERE IS". CONSUMERS MAKES NO REPRESENTATION OR WARRANTY WHATSOEVER IN THIS AGREEMENT, EXPRESSED, IMPLIED OR STATUTORY, INCLUDING, WITHOUT LIMITATION, ANY REPRESENTATION OR WARRANTY AS TO THE VALUE, QUANTITY, CONDITION, SALEABILITY, OBSOLESCENCE, MERCHANTABILITY, FITNESS OR SUITABILITY FOR USE OR WORKING ORDER OF ANY OF CAMPBELL 3, NOR DOES CONSUMERS REPRESENT OR WARRANT THAT THE USE OR OPERATION OF CAMPBELL 3 WILL NOT VIOLATE PATENT, TRADEMARK OR SERVICE MARK RIGHTS OF ANY THIRD PARTIES. THE PROVISIONS OF THIS SECTION 9.7 SHALL GOVERN OVER ANY CONFLICTING PROVISIONS OF THIS AGREEMENT. Notwithstanding the foregoing, NORTHERN and WOLVERINE shall have the benefit, in proportion to their percentage ownership interests in the property included in CAMPBELL 3, of all patent, trademark and service mark rights running to CONSUMERS in connection with the property included in CAMPBELL 3.

9.8 Destruction.

9.8.1 If the property included in CAMPBELL 3 or any portion thereof should be damaged or destroyed to the extent that the cost of repairs or reconstruction is estimated to be covered by the aggregate amount of insurance coverage (including any deductible) carried by CONSUMERS for the benefit of CONSUMERS and the

COOPERATIVES pursuant to Article 11 hereof and covering the cost of such repairs or reconstruction, then CONSUMERS shall cause such repairs or reconstruction to be made so that the property included in CAMPBELL 3 shall be restored to substantially the same general condition, character or use as existed prior to such damage or destruction, and CONSUMERS and NORTHERN and WOLVERINE shall share the cost not reimbursed by such insurance in proportion to their percentage ownership interests in the property included in CAMPBELL 3.

9.8.2 If the property included in CAMPBELL 3 or any portion thereof should be damaged or destroyed to the extent that the cost of repairs or reconstruction is estimated to be more than the aggregate amount of insurance coverage (including any deductible) carried by CONSUMERS for the benefit of CONSUMERS and the COOPERATIVES pursuant to Article 11 hereof and covering the cost of such repairs or reconstruction, then, if CONSUMERS elects to repair and reconstruct the property included in CAMPBELL 3 and upon agreement of CONSUMERS and NORTHERN and WOLVERINE, CONSUMERS shall cause such repairs or reconstruction to be made and CONSUMERS and NORTHERN and WOLVERINE shall share the costs of such repairs or reconstruction not reimbursed by such insurance, in proportion to their percentage ownership interests in the property included in CAMPBELL 3; provided, however, that:

(a) If both WOLVERINE and NORTHERN elect not to join CONSUMERS in repairing and reconstructing the property included in CAMPBELL 3 (each COOPERATIVE so electing being hereinafter called a "Retiring Cooperative"), then the PARTIES shall determine the monetary amount to be paid by CONSUMERS to each Retiring Cooperative or by each Retiring Cooperative to CONSUMERS, as provided for in Paragraph (c) of this Section 9.8.2. Upon payment of such monetary amount by CONSUMERS to each Retiring Cooperative or by each Retiring Cooperative to CONSUMERS, as the case may require as set forth in said Paragraph (c), WOLVERINE and NORTHERN shall transfer their ownership interests in the property included in CAMPBELL 3 to CONSUMERS, free and clear of all liens and encumbrances, and this Agreement shall be deemed to have expired as to such PARTIES.

(b) If either WOLVERINE or NORTHERN, and not both, elects not to join CONSUMERS in repairing and reconstructing the property included in CAMPBELL 3 (the COOPERATIVE so electing being hereinafter called the "Retiring Cooperative"), then the other COOPERATIVE (the "Non-retiring Cooperative") not so electing shall have the following options:

(1) Not to pay to the Retiring Cooperative nor to receive from the Retiring Cooperative any portion of the monetary amount provided for in Paragraph (c) of this Section 9.8.2; in

which event CONSUMERS shall pay to the Retiring Cooperative or the Retiring Cooperative shall pay to CONSUMERS, as the case may require as set forth in said Paragraph (c), such monetary amount; the Retiring Cooperative shall transfer its ownership interest in the property included in CAMPBELL 3 to CONSUMERS, free and clear of all liens and encumbrances; and this Agreement shall be deemed to have expired as to the Retiring Cooperative. In this event, CONSUMERS and the Non-retiring Cooperative shall share the cost of repairing and reconstructing the property included in CAMPBELL 3 in proportion to their ownership interests in the property included in CAMPBELL 3 after the transfer provided for in the preceding sentence, or

(2) To pay to the Retiring Cooperative or to receive from the Retiring Cooperative, as the case may require as set forth in Paragraph (c) of this Section 9.8.2, a portion of the monetary amount provided for in said Paragraph (c), such portion to be determined by multiplying such monetary amount by the percentage represented by "A" in the following equation:

$$A = \frac{B}{B+C} \times 100$$

Where: A = The Non-retiring Cooperative's percentage ownership interest in the property included in CAMPBELL 3 after transfer of the Retiring Cooperative's ownership interest in such property.

B = The Non-retiring Cooperative's percentage ownership interest in the property included in CAMPBELL 3 before transfer of the Retiring Cooperative's ownership interest in such property.

C = CONSUMERS' percentage ownership interest in the property included in CAMPBELL 3 before transfer of the Retiring Cooperative's ownership interest in such property.

CONSUMERS shall pay to the Retiring Cooperative or the Retiring Cooperative shall pay to CONSUMERS, as the case may require as set forth in Paragraph (c) of this Section 9.8.2, the balance of the monetary amount provided for in said Paragraph (c). If the Nonretiring Cooperative exercises this option, then

(i) upon payment of such monetary amount by CONSUMERS and the Non-retiring Cooperative to the Retiring Cooperative or by the Retiring Cooperative to CONSUMERS and the Non-retiring Cooperative, as the case may require as set forth in said Paragraph (c), the Retiring Cooperative shall transfer its ownership interest in the property included in CAMPBELL 3 to CONSUMERS and the Non-retiring Cooperative, in proportion to the respective portions of such monetary amount which CONSUMERS and the Non-retiring Cooperative have paid to or received from the Retiring Cooperative, and this Agreement shall be deemed to have expired as to the Retiring Cooperative, and

(ii) CONSUMERS and the Non-retiring Cooperative shall each contribute to the cost of the reconstruction and repair of the property included in CAMPBELL 3 in proportion to their ownership interests in the property included in CAMPBELL 3 after such transfer.

(c) The monetary amount to be paid to or received from a Retiring Cooperative pursuant to the provisions of Paragraphs (a) or (b) of this Section 9.8.2, as may be applicable, shall be determined in accordance with the following equation:

$$P = W \times X$$

Where: P = The monetary amount to be paid to or received from a Retiring Cooperative. If P is positive, the monetary amount shall be paid to such Retiring Cooperative; and if P is negative, the monetary amount shall be received from such Retiring Cooperative.

W = Such Retiring Cooperative's percentage ownership interest (expressed as a decimal) in the property included in CAMPBELL 3 before transfer of such Retiring Cooperative's ownership interest in such property.

X = The net salvage value (as defined in the Uniform System of Accounts) of the property included in CAMPBELL 3 at the time such Retiring Cooperative elects not to join CONSUMERS in repairing and reconstructing the property included in CAMPBELL 3.

ARTICLE 10

TAXES

10.1 CONSUMERS shall have complete authority and responsibility for administering, coordinating, filing returns, making property tax declarations, paying, seeking official tax rulings or determinations, and other related functions pertaining to all taxes, payments in lieu of taxes, assessments, impositions, charges and related costs of every kind and nature, ordinary or extraordinary, general or special, foreseen or unforeseen, settled or pending settlement, including, but not limited to, property, sales, use and payroll taxes, connected with or arising out of the construction, ownership, operation, maintenance, alteration, repair, rebuilding, use, or retirement of CAMPBELL 3 or any part thereof, which are or may be imposed by any Federal, State, local municipal, interregional, or foreign government, or quasi-governmental authority; provided, however, that such authority and responsibility shall not extend to any act or action affecting any exemption or special tax treatment to which the COOPERATIVES may be entitled. In connection therewith, the COOPERATIVES do hereby make and appoint CONSUMERS to be their attorney-in-fact, to act in their name, place and stead for the purpose of filing returns, making property tax declarations, negotiating, seeking adjustments or revisions, protesting, seeking official tax rulings or determinations, contesting, making application for and claiming any and all exclusions, exemptions, deductions, credits and elections pertaining to all such taxes, payments in lieu of taxes, assessments, impositions, charges and related costs, but such appointment shall not extend to any act or action affecting any exemption or special tax treatment to which the COOPERATIVES may be entitled. The COOPERATIVES, their subsidiaries, agents or assigns shall promptly join in any action reasonably required which is consistent with the exercise by CONSUMERS of the tax authority described herein.

10.2 All such taxes, payments in lieu of taxes, assessments, impositions, charges and related costs shall be shared and borne by CONSUMERS and the COOPERATIVES in proportion to their respective percentage ownership interests in CAMPBELL 3; provided, however, the COOPERATIVES shall be entitled to the entire benefit to the extent of actual realization, of all exemptions from and reductions of taxes, payments in lieu of taxes, assessments, impositions, charges and related costs of every kind and nature, foreseen or unforeseen, settled or pending settlement, including but not limited to property, sales, use and payroll taxes, connected with or arising out of the construction, ownership, operation, maintenance, alteration, repair, rebuilding, use or retirement of CAMPBELL 3 or any part thereof, which may be realized because of the provisions, if any, of the Constitutions of Michigan and the United States of America, statutes, ordinances, rules, regulations and laws applicable to the COOPERATIVES and not CONSUMERS.

The portion of such taxes, payments in lieu of taxes, assessments, impositions, charges and related costs that are to be borne by the COOPERATIVES as set forth above in this Section 10.2 shall be paid by the COOPERATIVES in accordance with Sections 3.5 and 7.3, as applicable.

10.3 Except as the provisions of Section 10.2 (entitling the COOPERATIVES to the entire benefit as is realized from all exemptions from and reductions of taxes) are applicable, it is understood and agreed that such taxes as shall be shared by the COOPERATIVES under Section 10.2 shall include as the COOPERATIVES' obligation that portion of CONSUMERS' Michigan Single Business Tax cost which shall be determined solely by multiplying all "compensation" (as that term is defined in the Michigan Single Business Tax Act) attributable to the construction, operation, maintenance, alteration, repair, rebuilding, use, or retirement of CAMPBELL 3 by the statutory Michigan Single Business Tax rate.

10.4 The COOPERATIVES shall be responsible for all sales, transfer and recording fees incurred in connection with the conveyance(s) to the COOPERATIVES of an undivided ownership interest in the property included in CAMPBELL 3 pursuant to this Agreement.

10.5 Notwithstanding the generality of Section 10.1 above, the foregoing provisions of this Article 10 shall not apply to any tax in the nature of an income tax.

10.6 Notwithstanding any other provision of this Agreement, CONSUMERS and the COOPERATIVES do not intend to create hereby at law any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. CONSUMERS shall have the authority at its sole option to elect under Section 761(a) of the Internal Revenue Code of 1954, as amended, to exclude the transactions created by this Agreement from the application of Subchapter K, Chapter 1 of the Code.

ARTICLE 11

INSURANCE

11.1 Except with regard to Directors and Officers Liability Insurance, CONSUMERS shall maintain in force, for the benefit of CONSUMERS and the COOPERATIVES as their ownership interests in the property included in CAMPBELL 3 shall appear, such available insurance with respect to CAMPBELL 3 as CONSUMERS, in its sole judgment, would maintain in force if it were the sole owner of CAMPBELL 3.

11.1.1 The costs of such insurance policies (and any additional insurance which may be agreed upon by CONSUMERS and NORTHERN and WOLVERINE pursuant to Section 11.1.3) shall be shared by the PARTIES in proportion to their respective percentage ownership interests in the property included in CAMPBELL 3. The COOPERATIVES' share of such costs shall be paid in accordance with Sections 3.5 or 7.3, as applicable.

11.1.2 Both NORTHERN and WOLVERINE shall be named as additional insureds in such insurance policies. CONSUMERS shall endeavor to have the insurance underwriters furnish NORTHERN and WOLVERINE with a Certificate of Insurance of each such insurance policy. In addition, CONSUMERS shall endeavor to have each of such policies endorsed so as to provide that both NORTHERN and WOLVERINE shall be given the same advance notice of cancellation or material change as is required to be given to CONSUMERS. Loss or claim, if any, under such insurance policies shall be adjusted and settled by CONSUMERS with the insurance underwriters.

11.1.3 Either NORTHERN or WOLVERINE may request additional insurance to the extent available and, if CONSUMERS and NORTHERN and WOLVERINE agree that the requested additional insurance is necessary or desirable, CONSUMERS shall purchase such requested additional insurance for the benefit of CONSUMERS and the COOPERATIVES as their ownership interests in the property included in CAMPBELL 3 shall appear, and the costs thereof shall be shared by the PARTIES in accordance with Section 11.1.1. If NORTHERN and WOLVERINE and CONSUMERS do not so agree, either NORTHERN or WOLVERINE may purchase such requested additional insurance at its own expense, or may request CONSUMERS to purchase such insurance at the expense of the requesting PARTY, and (a) the proceeds from any claim arising through such additional insurance shall be disbursed to the PARTY at whose expense the insurance was purchased and (b) loss or claim, if any, under such additional insurance shall be adjusted and settled by said PARTY with the insurance underwriters.

11.1.4 Any refunds of insurance premiums shall be allocated among the PARTIES on the same basis as the premium payment allocation from which such refund was derived.

11.1.5 In the event of damage to any of the property included in CAMPBELL 3 exceeding the amount of insurance carried by CONSUMERS pursuant to this Agreement, it is agreed that the proceeds from such insurance shall be shared by the PARTIES to this Agreement and such other parties as may have insurable interests in the damaged property on a pro-rata basis based on their relative insurable interests in the damaged property.

ARTICLE 12

FUEL

12.1 Procurement and Ownership

CONSUMERS shall have sole authority to procure all fuel for CAMPBELL 3, and shall take all steps which it deems necessary or appropriate for that purpose. Without limiting the generality of the preceding sentence, CONSUMERS shall have the right to enter into any agreements on behalf of the PARTIES for the purchase of such fuel which CONSUMERS, in its sole discretion, shall deem desirable.

With respect to such fuel which is delivered to CAMPBELL 3 on and after July 1, 1980, CONSUMERS shall sell to each COOPERATIVE, and each COOPERATIVE shall purchase from CONSUMERS, a 100% ownership interest in the number of dry tons of fuel which such COOPERATIVE, in accordance with the provisions of this Article 12, is required to own for the purpose of establishing and maintaining its portion of the fuel stockpile for CAMPBELL 3. Such ownership interest of such COOPERATIVE in such fuel shall automatically pass to it without further action by the PARTIES. For purposes of this Agreement, CONSUMERS shall be deemed to have a 100% ownership interest in the remainder of the fuel stockpile for CAMPBELL 3, including all fuel which is delivered to CAMPBELL 3 prior to July 1, 1980.

Notwithstanding any provision to the contrary in this Agreement, it is agreed by the PARTIES that the terms and conditions of all agreements for the purchase of fuel for CAMPBELL 3 shall be regarded as confidential information of CONSUMERS and shall not be subject to inspection or perusal by the COOPERATIVES; provided, however, that the COOPERATIVES may from time to time employ an independent consultant, which is acceptable to the Administrative Committee, to inspect and peruse such agreements for purposes of verifying to the COOPERATIVES and the Administrator of the Rural Electrification Administration that the expenditures made by CONSUMERS for the purchase of fuel for CAMPBELL 3 are in accordance with the terms and conditions of such agreements. The terms and conditions of such agreements shall not, however, be made available to the COOPERATIVES or any third parties through said independent consultant and said independent consultant shall be required to agree in writing not to make such disclosure.

12.2 Management

CONSUMERS shall have sole authority to manage all fuel for CAMPBELL 3 according to its discretion and judgment including, without limitation, unloading, handling and storage.

12.3 Establishment of Each COOPERATIVE'S Portion of the Fuel Stockpile

During the period beginning with July 1, 1980 and continuing through

September 30, 1980, CONSUMERS shall (a) sell to NORTHERN, for the purpose of establishing NORTHERN'S portion of the fuel stockpile, a proportionate share, to the extent practicable, of each shipment of fuel delivered to CAMPBELL 3 during such period so that the aggregate amount of fuel purchased by NORTHERN from CONSUMERS during such period in accordance with this Section 12.3 shall be equal to 3,800 dry tons, and (b) sell to WOLVERINE, for the purpose of establishing WOLVERINE'S portion of the fuel stockpile, a proportionate share, to the extent practicable, of each shipment of fuel delivered to CAMPBELL 3 during such period so that the aggregate amount of fuel purchased by WOLVERINE from CONSUMERS during such period in accordance with this Section 12.3 shall be equal to 1,900 dry tons. Payment by the COOPERATIVES for such fuel being purchased by them for the purpose of establishing their respective portions of the fuel stockpile for CAMPBELL 3 shall be made as follows:

(1) On or before August 15, 1980, CONSUMERS shall furnish the COOPERATIVES an invoice showing (a) the total fuel deliveries and payments, and the COOPERATIVES' share thereof, which CONSUMERS has made in regard to fuel delivered to CAMPBELL 3 during the month of July, 1980, and (b) the current estimate of total fuel deliveries and payments, and the COOPERATIVES' share thereof, which CONSUMERS expects to make in regard to fuel delivered to CAMPBELL 3 during the month of August, 1980. On or before the first day of each month beginning with the month of September, 1980, CONSUMERS shall furnish the COOPERATIVES an invoice showing

the current estimate of total fuel deliveries and payments, and the COOPERATIVES' share thereof, which CONSUMERS expects to make in regard to fuel delivered to CAMPBELL 3 during such month.

(2) The invoice referred to in the first sentence of (1) above shall be paid by the COOPERATIVES at the Closing. The invoices referred to in the second sentence of (1) above shall be paid by the COOPERATIVES so that CONSUMERS will receive the funds by the 25th day of such month or the first working day thereafter if the payment date falls on other than a working day.

(3) Adjustments for the difference between estimated payments and actual costs shall be made on the invoice submitted for the second month following the month in which such costs were incurred.

(4) All payments shall be made in immediately available funds payable to Consumers Power Company and shall be sent to Consumers Power Company, Attention: Treasurer, 212 West Michigan Avenue, Jackson, Michigan 49201, or by wire transfer to a bank designated by CONSUMERS.

(5) Any payment not made on or before the due dates set forth in (2) above shall constitute an act of default under Section 17.1 hereof.

12.4 <u>Maintenance of Each COOPERATIVE'S Portion of the Fuel Stockpile</u>

Except as otherwise provided in this paragraph, (a) NORTHERN shall have a continuing obligation to maintain its portion of the fuel stockpile at a level of 3,800 dry tons, and (b) WOLVERINE shall have a continuing obligation to maintain its portion of the fuel stockpile at a level of 1,900 dry tons. From time to time the Administrative Committee may review and increase or decrease, if necessary, the number of dry tons of fuel which are to be maintained by each COOPERATIVE in its portion of the fuel stockpile during the long-range operation of CAMPBELL 3. In addition, prior to and during extended periods of time in which fuel shipments are expected to be decreased because of circumstances beyond CONSUMERS' control, the Administrative Committee may establish temporary schedules of additional buildup or draw-down, as the case may require, of each COOPERATIVE'S portion of the fuel stockpile.

Any change in the dry tons of fuel in the fuel stockpile for CAMPBELL 3 as a result of the annual fuel stockpile inventory conducted by CONSUMERS shall be allocated to the PARTIES in proportion to their fuel consumption during the previous calendar year. If, as a result of such annual fuel stockpile inventory, each COOPERATIVE'S portion of the fuel stockpile is increased above or decreased below the level to be maintained by such COOPERATIVE as specified in the first paragraph of this Section 12.4 (or such other level as may be agreed upon by the Administrative Committee with respect to such COOPERATIVE pursuant to said first paragraph), then the amount of such increase or decrease in dry tons shall be reflected for such COOPERATIVE in AF of the formula set forth below in this Section 12.4.

Each COOPERATIVE shall make payments to CONSUMERS each month for the purpose of maintaining such COOPERATIVE'S portion of the fuel stockpile at the level to be maintained by such COOPERATIVE as specified in the first paragraph of this Section 12.4 (or such other level as may be agreed upon by the Administrative Committee with respect to such COOPERATIVE pursuant to said first paragraph). Such payments shall begin with the month of October, 1980. Such payments shall be for fuel consumed by CAMPBELL 3 from such COOPERATIVE'S portion of the fuel stockpile. Such payments shall be determined each month in accordance with the following formula:

$$MP = FP \left[\left(TF \times \frac{MkWh}{TkWh}\right) + AF \right]$$

Where: MP = Such COOPERATIVE'S payment to CONSUMERS.

FP = The weighted average cost per dry ton of fuel delivered to CAMPBELL 3 in the month for which such payment is being made.

TF = The estimated total number of dry tons of fuel to be consumed by CAMPBELL 3 for the PARTIES and all other co-owners of CAMPBELL 3, if any, in the month for which such payment is being made (including fuel consumed by CAMPBELL 3 for test electric energy, if any).

MkWh = The estimated amount of electric energy in kilowatthours generated by CAMPBELL 3 from such COOPERATIVE'S portion of the fuel stockpile in the month for which such payment is being made. Such electric energy shall include that generated by CAMPBELL 3 (i) for such COOPERATIVE in accordance with Section 6.2, (ii) for such COOPERATIVE'S share of test electric energy, if any, purchased by CONSUMERS from such COOPERATIVE in such month in accordance with Section 6.5, (iii) for such COOPERATIVE'S Planned Excess Electric Capability and Unplanned Excess Electric Capability purchased by CONSUMERS from such COOPERATIVE in such month in accordance with Sections 6.6.1 and 6.7, respectively, and (iv) for any unused electric generating capability available to such COOPERATIVE which is used by CONSUMERS in accordance with Section 6.2.

TkWh = The estimated total amount of electric energy in kilowatthours generated by CAMPBELL 3 for the PARTIES and all other co-owners of CAMPBELL 3, if any, in the month for which such payment is being made. Such electric energy shall include any test electric energy generated by CAMPBELL 3 in such month.

AF = The number of dry tons by which such COOPERATIVE'S portion of the fuel stockpile at the beginning of the month for which such payment is being made is more than or less than, as the case may be, the number of dry tons such COOPERATIVE is required to maintain in its portion of the fuel stockpile in accordance with the first paragraph of this Section 12.4. In the event that the number of dry tons in such COOPERATIVE'S portion of the fuel stockpile exceeds the number of dry tons such COOPERATIVE is required to maintain as aforesaid, then AF shall be a negative number; and in the event the number of dry tons in such COOPERATIVE'S portion of the fuel stockpile is less than the number of dry tons such COOPERATIVE is required to maintain as aforesaid, then AF shall be a positive number. However, if AF is a negative number and is greater than $(TF \times \frac{MkWh}{TkWh})$ in such month, then only that portion of the total value of AF which is equal to $(TF \times \frac{MkWh}{TkWh})$ shall be used in the above calculation for such month.

MkWh shall be estimated, for the purpose of applying the above formula, taking into account the historic capacity factor, exclusive of scheduled maintenance of CAMPBELL 3, associated with (a) such COOPERATIVE'S Electric Capability and Energy Entitlement in CAMPBELL 3, (b) such COOPERATIVE'S Planned Excess Electric Capability in CAMPBELL 3, and (c) such COOPERATIVE'S Unplanned Excess Electric Capability in CAMPBELL 3. TkWh shall be estimated, for the purpose of applying the above formula, taking into account the historic capacity factor of CAMPBELL 3 exclusive of its scheduled maintenance. FP shall be estimated for the purposes of applying the above formula. However, in the event that the actual value of FP in the month for which such payment is being made differs from the estimated value thereof, then in such event an adjustment shall be made, as set forth in (2) below, for any overpayment or underpayment which results from such difference. Payment by each COOPERATIVE for fuel consumed by

CAMPBELL 3 from such COOPERATIVE'S portion of the fuel stockpile for CAMPBELL 3 shall be made as follows:

(1) On or before the 5th day of each month, beginning with the month of October, 1980, CONSUMERS shall furnish such COOPERATIVE an invoice showing the payment required from such COOPERATIVE for such month.

(2) Any adjustment resulting from the difference between the actual value of FP from the estimated value thereof, as set forth in the fourth paragraph of this Section 12.4, shall be reflected in the invoice submitted for the first month following the month in which actual costs giving rise to such difference were incurred.

(3) These invoices shall be paid by such COOPERATIVE so that CONSUMERS will receive the funds by the 25th day of such month or the first working day thereafter if the payment date falls on other than a working day.

(4) All payments shall be made in immediately available funds payable to Consumers Power Company and shall be sent to Consumers Power Company, Attention: Treasurer, 212 West Michigan Avenue, Jackson, Michigan 49201, or by wire transfer to a bank designated by CONSUMERS.

(5) Any payment not made on or before the due dates set forth in (3) above shall constitute an act of default under Section 17.1 hereof.

12.5 Fuel Consumed for Test Electric Energy

As is stated in Section 6.5, any net electric energy output from CAMPBELL 3 prior to the Commercial Operation Date of said unit shall be classified as test electric energy. The fuel consumed for such test electric energy generated prior to the Closing shall be furnished entirely by CONSUMERS. The fuel consumed for such test electric energy generated on and after the Closing shall be furnished by the PARTIES in proportion to their respective percentage ownership interests in CAMPBELL 3.

12.6 Retroactive Fuel Price Adjustments

In the event that a retroactive fuel price adjustment becomes necessary in accordance with the terms and conditions of any of the agreements for the purchase of fuel for CAMPBELL 3, CONSUMERS shall promptly recalculate the payments, to the extent necessary, under Sections 12.3 and 12.4 after such retroactive fuel price adjustment becomes known to CONSUMERS. Any calculated retroactive payment adjustments shall be reflected as soon as practicable in an invoice submitted by CONSUMERS pursuant to Sections 12.3 or 12.4, as the case may require.

12.7 Survival of Obligations

The termination or expiration of this Agreement shall not discharge any PARTY of any obligation it owes any other PARTY under this Agreement by reason of any transaction, loss, cost, damage, expense or liability which shall occur or arise (or the circumstances, events or basis of which shall occur or arise) prior to such termination or expiration, including but not limited to the actions of CONSUMERS in retiring, salvaging or disposing of CAMPBELL 3 or any part thereof. It is the intent of the PARTIES hereby that any such obligation owed by any PARTY to any other PARTY (whether the same shall be known or unknown at the termination or expiration of this Agreement or whether the circumstances, events or basis of the same shall be known or unknown at the termination or expiration of this Agreement), shall survive the termination or expiration of this Agreement.

ARTICLE 13

TRANSFER OF INTEREST IN OR PARTITION OF CAMPBELL 3

13.1 Special Nature of CAMPBELL 3.

The PARTIES recognize that when CAMPBELL 3 shall have been placed in service, it will be an integral part of the facilities required to provide adequate service in their respective service territories and the service territories of other co-owners of CAMPBELL 3, if any, and that the physical partition of CAMPBELL 3 or any material part thereof would be impossible and impractical and wholly inconsistent with the purposes for which this Agreement is made. Accordingly, and in recognition of these circumstances, the PARTIES agree as provided in the remaining Sections of this Article 13.

As used in this Article 13, (a) the term "selling PARTY" means any PARTY which hereafter desires to dispose of (whether by sale, conveyance, transfer, assignment, lease or otherwise) all or any portion of its ownership interest in CAMPBELL 3 to any other PARTY, any other co-owner of CAMPBELL 3 or any third party, (b) the term "other co-owner of CAMPBELL 3" means any entity which has acquired from CONSUMERS, either prior or subsequent to the date of this Agreement, an undivided ownership interest as a tenant in common in the property included in CAMPBELL 3 pursuant to a separate CAMPBELL 3 Ownership and Operating Agreement between CONSUMERS and such entity and to which NORTHERN and WOLVERINE are not signatories, and (c) the term "third party" means any entity other than the PARTIES and other co-owners of CAMPBELL 3.

13.2 Transfer of Ownership Interests in CAMPBELL 3 to Third Parties.

13.2.1 If NORTHERN or WOLVERINE is the selling PARTY and shall desire to dispose of (whether by sale, conveyance, transfer, assignment, lease or otherwise) all or any portion of its ownership interest in CAMPBELL 3 to any third party or parties, NORTHERN or WOLVERINE, as the case may be, shall give each of the other PARTIES written notice thereof, and any such transaction with a third party or parties shall not be consummated until both of the other PARTIES have determined not to exercise their right of first refusal, as set forth in this paragraph. Such written notice shall fully disclose the nature and terms of the proposed transaction and the identity of the third party or parties involved. Upon receipt of such written notice, the other PARTIES shall have the first right to acquire the selling PARTY'S ownership interest in CAMPBELL 3, which the selling PARTY proposes to dispose of to the third party or parties, upon the same terms and conditions which the selling PARTY proposes to make with the third party or parties. Within 60 days following receipt of such notice, the other PARTIES shall consult with each other concerning the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, and the proportions thereof which each of the other PARTIES may be interested in acquiring. Within 90 days following receipt of such notice, each of the other PARTIES shall give written notice to the selling PARTY stating whether or not it elects to acquire the selling PARTY'S undivided ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties. If only one of the other PARTIES elects to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, then such other PARTY shall acquire such ownership interest. If both of the other PARTIES elect to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, then such other PARTIES shall acquire such ownership interest in such proportions as they may have agreed upon in writing or, in the absence of such agreement, each of such other PARTIES shall acquire such ownership interest in proportion to the ratio which its initial ownership interest in CAMPBELL 3 bears to the sum of the initial ownership interests of such other PARTIES in CAMPBELL 3. If one or both of such other PARTIES elect to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, the selling PARTY, as soon as practicable, shall execute such instruments as may be necessary and appropriate to effectuate such sale, conveyance, transfer, assignment, lease or other disposition, as the case may be, to such other PARTY or PARTIES, free and clear of all liens, charges and encumbrances for which the selling PARTY, as among the PARTIES, is responsible, including the indenture of the selling PARTY.

If CONSUMERS is the selling PARTY and shall desire to dispose of (whether by sale, conveyance, transfer, assignment, lease or otherwise) all or any portion of its ownership interest in CAMPBELL 3 to any third party or parties, CONSUMERS shall give each of the other PARTIES and other co-owners of CAMPBELL 3, if any, written notice thereof, and any such transaction with a third party or parties shall not be consummated until all of the other PARTIES and other co-owners, if any, have determined not to exercise their right of first refusal, as set forth in this paragraph. Such written notice shall fully disclose the nature and terms of the proposed transaction and the identity of the third party or parties involved. Upon receipt of such written notice, the other PARTIES and other co-owners of CAMPBELL 3, if any, shall have the first right to acquire the selling PARTY'S ownership interest in CAMPBELL 3, which the selling PARTY proposes to dispose of to the third party or parties, upon the same terms and conditions which the selling PARTY proposes to make with the third party or parties. Within 60 days following receipt of such notice, the other PARTIES and other co-owners of CAMPBELL 3, if any, shall consult with each other concerning the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, and the proportions thereof which each of the other PARTIES and other co-owners of CAMPBELL 3, if any, may be interested in acquiring. Within 90 days following receipt of such notice, each of the other PARTIES and other co-owners of CAMPBELL 3, if any, shall give written notice to the selling PARTY stating whether or not it elects to acquire the selling PARTY'S undivided ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties. If only one of the other PARTIES and other co-owners of CAMPBELL 3, if any, elects to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, then such other PARTY or other co-owner of CAMPBELL 3, as the case may be, shall acquire such ownership interest. If more than one of the other PARTIES and other co-owners of CAMPBELL 3, if any, elect to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, then such of the other PARTIES and other co-owners of CAMPBELL 3, which elect to acquire such ownership interest, shall acquire such ownership interest in such proportions as they may have agreed upon in writing or, in the absence of such agreement, each of such other PARTIES and other co-owners of CAMPBELL 3, which elect to acquire such ownership interest, shall acquire such ownership interest in proportion to the ratio which its initial ownership interest in CAMPBELL 3 bears to the sum of the initial ownership interests in CAMPBELL 3 of such other PARTIES and other co-owners of CAMPBELL 3 which elect to acquire such ownership interest. If one or more of such other PARTIES and other co-owners of CAMPBELL 3 elect to acquire the selling PARTY'S ownership interest in CAMPBELL which the selling PARTY proposes to dispose of to the third party or parties, the selling PARTY, as soon as practicable, shall execute such instruments as may be necessary and appropriate to effectuate such sale, conveyance, transfer, assignment, lease or other disposition, as the case may be, to such of the other PARTIES and other co-owners of CAMPBELL 3, which elect to acquire such ownership interest, free and clear of all liens, charges and encumbrances for which the selling PARTY, as among the PARTIES and other co-owners of

CAMPBELL 3, is responsible, including the indenture of the selling PARTY.

13.2.2 If NORTHERN or WOLVERINE is the selling PARTY and both of the other PARTIES elect not to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, as provided in the first paragraph of Section 13.2.1, the selling PARTY may consummate its proposed transaction with the third party or parties and dispose of such ownership interest to the third party or parties, provided, that such transaction is consummated within 240 days following receipt by such other PARTIES of the written notice first referred to in the first paragraph of Section 13.2.1; and provided, further, that the selling PARTY shall require (as a condition of or in connection with the sale, conveyance, transfer, assignment, lease or other disposition, and for the benefit of the other PARTIES) the third party or parties acquiring such ownership interest to assume and agree to be bound by the provisions of this Agreement and any amendments thereto, and in furtherance thereof the provisions of this Agreement shall be amended appropriately to reflect (i) the addition of such third party or parties as a party or parties to this Agreement, (ii) the ownership interest in CAMPBELL 3 acquired by such third party or parties and the decreased ownership interest in CAMPBELL 3 of the selling PARTY, and (iii) the rights, duties and obligations of the selling PARTY and such third party or parties under this Agreement. Further, the consummation of any transaction by the selling PARTY with a third party or parties shall not release the selling PARTY from any of its debts or liabilities to either of the other PARTIES which, at the time of the consummation of the transaction, have accrued under this Agreement, and any amendments thereto, unless the PARTIES shall agree in writing to the contrary.

If CONSUMERS is the selling PARTY and all of the other PARTIES and other co-owners of CAMPBELL 3, if any, elect not to acquire the selling PARTY'S ownership interest in CAMPBELL 3 which the selling PARTY proposes to dispose of to the third party or parties, as provided in the second paragraph of Section 13.2.1, the selling PARTY may consummate its proposed transaction with the third party or parties and dispose of such ownership interest to the third party or parties, provided, that such transaction is consummated within 240 days following receipt by such other PARTIES and other co-owners of CAMPBELL 3, if any, of the written notice first referred to in the second paragraph of Section 13.2.1; and provided, further, that the selling PARTY, at its election, shall (a) require (as a condition of or in connection with the sale, conveyance, transfer, assignment, lease or other disposition, and for the benefit of the other PARTIES) the third party or parties acquiring such ownership interest to assume and agree to be bound by the provisions of this Agreement and any amendments thereto, in which event the provisions of this Agreement shall be amended appropriately to reflect (i) the addition of such third party or parties as a party or parties to this Agreement, (ii) the ownership interest in CAMPBELL 3 acquired by such third party or parties and the decreased ownership interest in CAMPBELL 3 of the selling PARTY, and (iii) the rights, duties and obligations of the selling PARTY and such third party or parties under this Agreement; or (b) enter into a separate Ownership and Operating Agreement with such third party or parties in regard to the ownership interest in CAMPBELL 3 acquired by such third party or parties, in which event it is agreed, as between CONSUMERS and the COOPERATIVES, that for purposes of this Agreement (i) CONSUMERS' ownership interest in CAMPBELL 3 and CONSUMERS' rights, duties and obligations to the COOPERATIVES, and the COOPERATIVES' rights, duties and obligations to CONSUMERS, under this Agreement shall be deemed to be the same as they would have been in the absence of such disposition of ownership interest by CONSUMERS to such third party or parties, and (ii) all investment made by such third party or parties in CAMPBELL 3 shall be added to and deemed a part of CONSUMERS' investment in CAMPBELL 3. Further, the consummation of any transaction by the selling PARTY with a third party or parties shall not release the selling PARTY from any of its debts or liabilities to either of the other PARTIES which, at the time of the consummation of the transaction, have accrued under this Agreement, and any amendments thereto, unless the PARTIES shall agree in writing to the contrary.

13.2.3 The right of NORTHERN or WOLVERINE, as the case may be, to dispose of such ownership interest to a third party or parties, as set forth in the first paragraph of Section 13.2.2, is subject to the further condition that (i) if the selling PARTY shall undertake to consummate its proposed transaction at a time subsequent to 240 days following receipt of the written notice first referred to in the first paragraph of Section 13.2.1, or (ii) if the selling PARTY shall undertake to dispose of such ownership interest to a third party or parties other than those whose identity was disclosed in said notice, or (iii) if the selling PARTY shall undertake to dispose of such ownership interest upon different terms and conditions than were disclosed in said notice, then the other PARTIES shall be given written notice thereof and shall have the further right of first refusal, to the same extent and by the same procedure described in the first paragraph of Section 13.2.1, with respect to any of such proposed transactions described in (i), (ii) and (iii) of this sentence.

The right of CONSUMERS to dispose of such ownership interest to a third party or parties, as set forth in the second paragraph of Section 13.2.2, is subject to the further condition that (i) if the selling PARTY shall undertake to consummate its proposed transaction at a time subsequent to 240 days following receipt of the written notice first referred to in the second paragraph of Section 13.2.1, or (ii) if the selling PARTY shall undertake to dispose of such ownership interest to a third party or parties other than those whose identity was disclosed in said notice, or (iii) if the selling PARTY shall undertake to dispose of such ownership interest upon different terms and conditions than were disclosed in said notice, then the other PARTIES and other co-owners of CAMPBELL 3, if any, shall be given written notice thereof and shall have the further right of first refusal, to the same extent and by the same procedure described in the second paragraph of Section 13.2.1, with respect to any of such proposed transactions described in (i), (ii) and (iii) of this sentence.

13.2.4 The provisions of the foregoing Sections 13.2.1, 13.2.2 and 13.2.3 shall continue for the duration of this Agreement and shall be applicable to each and every occasion and whenever any PARTY desires to dispose of (whether by sale, conveyance, transfer, assignment, lease or otherwise) all or any portion of its ownership interest in CAMPBELL 3 to any third party or parties;

provided, that such provisions shall not be applicable to, and each of the PARTIES hereby consents to, the following:

(i) the transfer, assignment, pledge, hypothecation, mortgage or grant (by indenture of mortgage, deed of trust or otherwise) by any PARTY of its ownership interest in CAMPBELL 3, together with all or substantially all of its other electric utility property, for the purpose of securing bonds or other obligations for borrowed money issued or to be issued by it, including the effect of any after-acquired property clause of any such indenture of mortgage, deed of trust or other instrument now existing or hereafter created by such PARTY, or the realization on or enforcement of such security or the exercise by the trustee or the mortgagee, as the case may be, or the beneficiaries of such security of any of the rights, powers, or privileges provided for with respect thereto; or

(ii) the transferring by any PARTY to a third party of its undivided ownership interest in CAMPBELL 3, together with all or substantially all of its other electric utility property, whether by sale or pursuant to or as a result of a merger, consolidation or corporate reorganization; provided, that such third party, by written agreement or by operation of law, assumes the obligations of this Agreement, and any amendments thereto, of the PARTY so transferring; or

(iii) the selling, transferring, assigning, conveying or otherwise disposing by CONSUMERS of any portion of its ownership interest in CAMPBELL 3 to any of the utilities listed in Appendix I; provided, that if CONSUMERS disposes of any portion of its ownership interest in CAMPBELL 3 to any of the utilities listed in Appendix I, then CONSUMERS, at its election, shall (a) require (as a condition of or in connection with the sale, conveyance, transfer, assignment, lease or other disposition, and for the benefit of the other PARTIES) such utility acquiring such ownership interest to assume and agree to be bound by the provisions of this Agreement and any amendments thereto, in which event the provisions of this Agreement shall be amended appropriately to reflect (i) the addition of such utility or utilities as a party or parties to this Agreement, (ii) the ownership interest in CAMPBELL 3 acquired by such utility or utilities and the decreased ownership interest in CAMPBELL 3 of CONSUMERS, and (iii) the rights, duties and obligations of CONSUMERS and such utility or utilities under this Agreement; or (b) enter into a separate Ownership and Operating Agreement with such utility or utilities in regard to the ownership interest in CAMPBELL 3 acquired by such utility or utilities, in which event it is agreed, as between CONSUMERS and the COOPERATIVES, that for purposes of this Agreement (i) CONSUMERS' ownership interest in CAMPBELL 3 and CONSUMERS' rights, duties and obligations to the COOPERATIVES, and the COOPERATIVES' rights, duties and obligations to CONSUMERS, under this Agreement shall be deemed to be the same as they would have been in the absence of such disposition of ownership interest by CONSUMERS to such utility or utilities, and (ii) all investment made by such utility or utilities in CAMPBELL 3 shall be added to and deemed a part of CONSUMERS' investment in CAMPBELL 3; or

(iv) the selling, transferring, assigning, conveying or otherwise disposing by CONSUMERS of property included in CAMPBELL 3 in the exercise of its rights, under Sections 6.8.2 and 7.5 of this Agreement, to replace, modify, renew, retire, dispose of and salvage any part of said property; or

(v) the transfer, assignment, pledge, hypothecation, mortgage or grant by any PARTY of its ownership interest in pollution control facilities pursuant to Section 8.1 of this Agreement.

13.3 <u>Transfer of Ownership Interests in CAMPBELL 3 by One PARTY to One or Both of the Other PARTIES.</u>

Except as otherwise provided in Paragraph (b) of Section 9.8.2 hereof, each of the PARTIES retains complete freedom to dispose of all or any portion of its ownership interest in CAMPBELL 3 to one or both of the other PARTIES. Such disposition (whether by sale, conveyance, transfer, assignment, lease or otherwise) shall be made upon such terms and conditions as may be agreed upon by the selling PARTY and the purchasing PARTY or PARTIES; provided, that if only one of the other PARTIES is the purchasing PARTY, then nothing in the arrangements made by the selling PARTY and the purchasing PARTY in regard to such disposition of ownership interest shall be prejudicial to the rights of the other PARTY. Further, in the event of any such transfer of ownership interest by the selling PARTY to one or both of the other PARTIES, then this Agreement shall be appropriately amended to reflect the effect of such change in ownership interest on the rights, duties and obligations of the selling PARTY and the purchasing PARTY or PARTIES under this Agreement.

13.4 Transfer of Ownership Interest in CAMPBELL 3 by A PARTY to Another Co-Owner of CAMPBELL 3.

Each of the PARTIES retains complete freedom to dispose of all or any portion of its ownership interest in CAMPBELL 3 to any other co-owner of CAMPBELL 3. Such disposition (whether by sale, conveyance, transfer, assignment, lease or otherwise) shall be made upon such terms and conditions as may be agreed upon by the selling PARTY and such purchasing co-owner of CAMPBELL 3; provided, that nothing in the arrangements made by the selling PARTY and such purchasing co-owner of CAMPBELL 3 in regard to such disposition of ownership interest shall be prejudicial to the rights of the other PARTIES under this Agreement or prejudicial to the rights of any signatory, excepting such purchasing co-owner of CAMPBELL 3, to the separate CAMPBELL 3 Ownership and Operating Agreement between CONSUMERS and such purchasing co-owner of CAMPBELL 3. Further, in the event of any such transfer of ownership interest by the selling PARTY to any other co-owner of CAMPBELL 3, then (a) this Agreement shall be appropriately amended to reflect the effect of the decrease in ownership interest of the selling PARTY on the rights, duties and obligations of the selling PARTY and the other PARTIES under this Agreement, and (b) the selling PARTY shall require such purchasing co-owner of CAMPBELL 3 to agree to appropriate amendments of the separate CAMPBELL 3 Ownership and Operating Agreement between CONSUMERS and such purchasing co-owner of CAMPBELL 3 in order to reflect the effect of the increase in ownership interest of such purchasing co-owner of CAMPBELL 3 on the rights, duties and obligations of such purchasing co-owner of CAMPBELL 3 and the other signatory or signatories to such separate CAMPBELL 3 Ownership and Operating Agreement.

13.5 Waiver of Right of Partition.

Each of the PARTIES agrees that it will not take any action, by judicial proceedings or otherwise, to partition CAMPBELL 3, nor any part thereof, in any way, whether by partition in kind or by sale and division of the proceeds thereof. Each of the PARTIES further waives the right of partition and the benefit of all statutory or common law that may now or hereafter authorize such partition of CAMPBELL 3 or any part thereof. In the event any such right of partition shall hereafter accrue, each PARTY shall from time to time upon the written request of the other PARTIES execute and deliver such further instruments as may be necessary to confirm the foregoing waiver and release of its right to partition. The foregoing provisions of this Section 13.5 shall be binding upon and inure to the benefit of the PARTIES, their respective successors and assigns, including mortgagees, receivers, trustees or other representatives and their respective successors and assigns, and shall run with the land.

13.6 Duration of Limitations.

Each provision of Sections 13.2, 13.4 and 13.5 of this Article 13 shall be effective to the full extent permitted by law, now or hereafter applicable, for the duration of this Agreement; provided, that if the rule against perpetuities, or any other rule of law, limits the time during which any such provision can be effective, then such provisions shall continue to be effective for no longer than the time limited by such other rule of law or 21 years after the death of the last survivor of all of the present corporate officers of CONSUMERS and NORTHERN and all of their children living on the date of this Agreement, whichever period is applicable. A list of such officers and their children is attached hereto as Exhibit B.

ARTICLE 14

ASSIGNMENT

14.1 Limitation on Assignability.

This Agreement shall not be assignable by any PARTY without the written consent of the other PARTIES, except that no such consent shall be required for any PARTY to assign this Agreement as an incident to the disposition of all of its ownership interest in accordance with Sections 13.2.1, 13.2.2 and 13.2.3 hereof or to assign a pro rata part of this Agreement as an incident to the disposition of any portion or portions of its ownership interest in accordance with said Sections 13.2.1, 13.2.2 and 13.2.3; and, further, each of the PARTIES hereby consents to the assignment of this Agreement as an incident to the disposition of a PARTY'S ownership interest, as permitted by paragraphs (i) and (ii) of Section 13.2.4 hereof, (i) for the purpose of securing bonds or other obligations for borrowed money or the realization on or enforcement of such security or the exercise by the trustee or the mortgagee, as the case may be, or the beneficiaries of such security of any of the rights, powers, or privileges provided for with respect thereto, or (ii) by sale or pursuant to or as a result of a merger, consolidation or corporate reorganization; and, further, the COOPERATIVES hereby agree that they will consent, if requested by CONSUMERS, to the assignment by CONSUMERS of a pro rata part of this Agreement as an incident to the disposition by CONSUMERS of any portion or portions of its ownership interest to any of the utilities listed in Appendix I as permitted by paragraph (iii) of said Section 13.2.4.

It is recognized by the PARTIES that the assignability of the Campbell 3 Back-up Requirements Agreement and the Campbell 3 Transmission Agreement is limited as set forth in the applicable provisions of those agreements.

14.2 Successors and Assigns.

This Agreement shall inure to the benefit of and be binding upon CONSUMERS and NORTHERN and WOLVERINE and their respective successors. This Agreement shall inure to the benefit of and be binding upon the assigns of CONSUMERS and NORTHERN and WOLVERINE when such assignment is made in accordance with the provisions of Section 14.1 hereof.

ARTICLE 15

LIABILITY

15.1 Liability to Third Parties.

Any liability or any payment, cost, expense or obligation arising from a claim of liability (after application thereto of any insurance coverage or proceeds) to a third party or parties against one or more of the PARTIES and arising from the acquisition of CAMPBELL 3 or any part thereof, the planning, engineering, design, licensing, procurement, construction, installation or completion of CAMPBELL 3 or any part thereof, the operation, use, management, control, maintenance, replacement, alteration, modification, renewal, rebuilding or repair of CAMPBELL 3 or any part thereof, the retirement, disposal, or salvaging of CAMPBELL 3 or any part thereof, or from any other action or failure to act by CONSUMERS (or its employees, agents or contractors) in carrying out any of the provisions of this Agreement in regard to CAMPBELL 3 or any part thereof, shall be shared by the PARTIES, irrespective of any question of negligence on the part of CONSUMERS, in proportion to their respective percentage ownership interests in CAMPBELL 3. If, by reason of any such liability or claim of liability (after application thereto of any insurance coverage or proceeds) to a third party or parties, any PARTY shall be called upon to make any payment or to incur any cost, expense or obligation in excess of that for which it is responsible under the provisions of this Section 15.1, then (a) if only one of the other PARTIES shall not have been called upon to make its full share of any payment or to incur its full share of any cost, expense or obligation for which it is responsible under the provisions of this Section 15.1, then such other PARTY shall reimburse the PARTY making such excess payment or incurring any such excess cost, expense or obligation to the full extent of the excess, or (b) if both of the other PARTIES shall not have been called upon to make their full shares of any payment or to incur their full shares of any cost, expense or obligation for which they are responsible under the provisions of this Section 15.1, then such other PARTIES shall reimburse the PARTY making such excess payment or incurring any such excess cost, expense or obligation for their respective shares of the excess. As used in this Section 15.1 and in Section 15.2, the term "negligence" excludes gross negligence and intentional wrongdoing.

15.2 Liability Among the PARTIES.

CONSUMERS shall not be liable to NORTHERN or WOLVERINE for any loss, cost, damage or expense incurred by NORTHERN or WOLVERINE as a result of any action or failure to act, whether through negligence or otherwise, by CONSUMERS (or its employees, agents or contractors) in carrying out any of the provisions of this Agreement in regard to the acquisition of CAMPBELL 3, or any part thereof, the planning, engineering, design, licensing, procurement, construction, installation or completion of CAMPBELL 3, or any part thereof, the operation, use, management, control, maintenance, replacement, alteration, modification, renewal, rebuilding or repair of CAMPBELL 3, or any part thereof, the retirement, disposal, or salvaging of CAMPBELL 3, or any part thereof, or any other matter concerning CAMPBELL 3, or any part thereof, except that

CONSUMERS shall be liable to NORTHERN and WOLVERINE for any action taken by CONSUMERS in bad faith and prejudicing NORTHERN and WOLVERINE for the benefit of CONSUMERS. It is agreed by the PARTIES, however, that in no event shall any of (i), (ii), and (iii) below be considered as actions taken by CONSUMERS in bad faith and prejudicing NORTHERN or WOLVERINE for the benefit of CONSUMERS:

(i) any decision by CONSUMERS, for either of the reasons specified in (a) and (b) of the first sentence in the first paragraph of Section 5.4.3, not to have CAMPBELL 3 in commercial operation by its scheduled Commercial Operation Date (as said scheduled Commercial Operation Date may be extended by all intervening events of force majeure),

(ii) the entering into this Agreement by CONSUMERS, or the continuation of construction of CAMPBELL 3 by CONSUMERS, under any conditions where it could be alleged or shown that CONSUMERS foresaw, or should have foreseen, that there might be a decision by CONSUMERS, for either of the reasons specified in (a) and (b) of the first sentence in the first paragraph of Section 5.4.3, not to have CAMPBELL 3 in commercial operation by its scheduled Commercial Operation Date (as said scheduled Commercial Operation Date may be extended by all intervening events of force majeure), and

(iii) the entering into this Agreement by CONSUMERS, or the continuation of construction of CAMPBELL 3 by CONSUMERS, under any conditions where it could be alleged or shown that CONSUMERS foresaw, or should have foreseen, that it might later suffer a financial inability to complete construction of CAMPBELL 3 as contemplated in Section 5.4.2.

ARTICLE 16

ADMINISTRATION

16.1 Administrative Committee.

From time to time various administrative and technical matters may arise in connection with the terms and conditions of this Agreement which will require the cooperation and consultation of the PARTIES and interchange of information. As a means of providing for such consultation and interchange, an Administrative Committee is hereby established with functions as described in Section 16.4 below. However, such Committee shall not diminish in any manner the authority of CONSUMERS as set forth in the various sections of this Agreement.

16.2 Membership.

The Administrative Committee shall have three (3) members. Within 60 days after execution of this Agreement, each PARTY shall designate in writing its representative on the Administrative Committee and shall promptly give written notice thereof to the other PARTIES. Thereafter, each PARTY shall promptly give written notice to the other PARTIES of any change in the designation of its representative on the Administrative Committee. The Chairman of the

Administrative Committee shall be the CONSUMERS representative, who shall be responsible for calling meetings and establishing agenda. All actions taken by the Administrative Committee must be by unanimous vote or consent of the members.

16.3 Meetings.

The Administrative Committee shall meet annually on a date and at a location to be announced by the Chairman at least 30 days in advance. Such other meetings as are reasonably required may be called by any member with as much advance notice as is practical. Meetings may be attended by other representatives of the PARTIES.

16.4 Functions.

The Administrative Committee shall have the following functions:

16.4.1 Provide liaison among all PARTIES at the management level and exchange information with respect to significant matters of licensing, design, construction, operation, and maintenance of CAMPBELL 3.

16.4.2 Appoint Ad Hoc Committees, the members of which need not be members of the Administrative Committee, as necessary to perform detailed work and conduct studies regarding matters requiring investigation.

16.4.3 Review and discuss disputes arising under this Agreement.

16.4.4 Provide liaison among all PARTIES with respect to the financial and accounting aspects of progress, performance and completion of construction, making of Capital Improvements, and operation of CAMPBELL 3.

16.5 Records.

The Administrative Committee shall keep written records of all meetings.

16.6 Expenses.

Each PARTY shall be responsible for the personal expenses of its representative and its other attendees. All other expenses incurred in connection with the performance by the Administrative Committee of its functions shall be allocated and paid as determined by the Administrative Committee.

ARTICLE 17

DEFAULT IN PAYMENTS

17.1 In addition to any other rights or remedies, legal or equitable, available to CONSUMERS, in the event NORTHERN or WOLVERINE or both at any time fails to make any payment when due to CONSUMERS under this Agreement, CONSUMERS shall have the right, at its election, to give written notice of such failure to the PARTY in default and in the event such failure continues for a period of 30 days after the giving of such notice, to withhold such PARTY'S share of the electrical output of CAMPBELL 3 until such payment has been made. In addition to withholding such PARTY'S share, each of the PARTIES which are not in default shall have the right to use such share, in proportion to the ratio which its Capability and Energy Entitlement bears to the sum of the Capability and Energy Entitlements of both of the PARTIES which are not in default, during all or any portion of the time until the overdue amount and interest are paid, but appropriate credit shall be given for the use of such share. If such failure occurs before the Commercial Operation Date of CAMPBELL 3, and is not remedied within 150 days after the giving of such notice, CONSUMERS shall have the additional right, at its election, to terminate the ownership interest of the PARTY in default by giving written notice of such election and tendering payment of the aggregate amounts theretofore received by CONSUMERS from such PARTY under the terms of this Agreement conditioned upon conveyance of the ownership interest in CAMPBELL 3 of such PARTY to CONSUMERS free and clear of all liens and encumbrances, and CONSUMERS shall thereby succeed to said ownership interest of such PARTY. All overdue payments, whether occurring before or after the Commercial Operation Date of CAMPBELL 3, shall bear interest at the rate of 1% per month or the highest lawful rate, whichever is lower. If either COOPERATIVE is in default it shall have a continuing obligation to indemnify and hold harmless the other PARTIES from and against any and all losses, costs, damages and expenses arising out of or resulting from its failure to make such payment when due.

ARTICLE 18

DISAGREEMENT

18.1 Consultation.

In accordance with the provisions of Article 16, the members of the

Administrative Committee will consult in connection with any major matter arising under this Agreement.

18.2 <u>Disagreement Prior to Commercial Operation</u>.

In view of the need and desire on the part of the PARTIES to complete construction and licensing of CAMPBELL 3 on schedule and for prompt decisions with respect thereto, the PARTIES agree that notwithstanding any disagreement with respect to any matter arising prior to the Commercial Operation Date of CAMPBELL 3, the decision of CONSUMERS with respect thereto shall be final and binding upon the PARTIES.

18.3 <u>Disagreement After Commercial Operation</u>.

If, after the Commercial Operation Date of CAMPBELL 3, any disagreement arises on major operation and maintenance matters pertaining to CAMPBELL 3, major Capital Improvements matters pertaining to CAMPBELL 3 or major retirement matters pertaining to CAMPBELL 3, such matters shall be discussed by the members of the Administrative Committee and timely mutual agreement sought among such members in regard thereto. Such major operation and maintenance matters pertaining to CAMPBELL 3, major Capital Improvements matters pertaining to CAMPBELL 3 and major retirement matters pertaining to CAMPBELL 3 are hereinafter referred to in this Section 18.3, and in Sections 18.4 and 18.5, as "plant subjects". If the members of the Administrative Committee unanimously agree to the resolution of any plant subject, such agreement shall be reported in writing to and shall be binding upon the PARTIES. In the unlikely event that the members of the Administrative Committee are unable to reach agreement within a reasonable time (giving due cognizance to the operating and maintenance schedules of CAMPBELL 3 and all other pertinent circumstances) with respect to any plant subject under consideration, the Vice President in charge of System Operations of CONSUMERS or the General Manager of NORTHERN or the General Manager of WOLVERINE can, by written notice to the members of the Administrative Committee, withdraw the matter from consideration by the Administrative Committee and submit the same for resolution to the Vice President in charge of System Operations of CONSUMERS and the General Manager of NORTHERN and the General Manager of WOLVERINE. If these senior representatives of the PARTIES unanimously agree to a resolution of the matter, such agreement shall be reported in writing to and shall be binding upon the PARTIES; but if said senior representatives fail to resolve the matter within seven days after its submission to them, then the matter may proceed to arbitration as provided in Section 18.4 or may proceed to litigation.

18.4 Arbitration.

If a disagreement should arise with respect to any plant subject which is not resolved by the Administrative Committee or the senior representatives of the PARTIES as provided in Section 18.3, then such disagreement may be settled by an Arbitration Board, which shall consist of three arbitrators as hereinafter provided, in accordance with the provisions of this Section 18.4. If, after the procedure for resolving such disagreement by the Administrative Committee or the senior representatives of the PARTIES as provided in Section 18.3 has been exhausted, any PARTY desires that such disagreement shall be settled by arbitration, it shall serve written notice upon the other PARTIES setting forth in detail such disagreement with respect to which arbitration is desired. Such disagreement shall be settled by arbitration if, after receipt of such written notice, all of the PARTIES shall agree in writing that such disagreement shall be settled by arbitration. Within a period of 30 days from the date of such agreement in writing to settle such disagreement by arbitration, each side of such disagreement shall select one arbitrator. Within a period of 60 days from the date of such agreement in writing to settle such disagreement by arbitration, the two arbitrators so selected shall meet and select one additional arbitrator. If either or both of the two arbitrators to be selected by the PARTIES, as herein provided, are not so selected within the specified 30-day period, or if the two arbitrators selected by the PARTIES shall fail to agree upon the selection of the additional arbitrator within the specified 60-day period, any PARTY may, upon written notice to the other PARTIES, apply to the American Arbitration Association for the appointment of the arbitrator or arbitrators who have not been so selected and such Association shall thereupon be empowered to select such arbitrator or arbitrators.

The arbitration proceedings shall be conducted at a place, to be designated by the Arbitration Board, within the operating area of one of the PARTIES. The Arbitration Board shall afford adequate opportunity to all of the PARTIES to present information with respect to the disagreement submitted to arbitration and may request further information from any PARTY. Except as provided in the preceding sentence, the PARTIES may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement. In the absence of any such agreement respecting the rules which are to govern any proceeding, the then current rules of the American Arbitration Association for the conduct of commercial arbitration shall govern the proceedings, except that if such rules shall conflict with the then current provisions of the laws of Michigan relating to arbitration, such conflict shall be governed by the then current provisions of the laws of Michigan relating to arbitration.

Procedural matters pertaining to the conduct of the arbitration and the award of the Arbitration Board shall be made upon a determination of a majority of the arbitrators. The findings and award of the Arbitration Board, so made upon a determination of a majority of the arbitrators, shall be final and conclusive with respect to the disagreement submitted for arbitration and shall be binding upon the PARTIES, except as otherwise provided by law. The PARTY or PARTIES on each side of the disagreement shall pay the fee and expenses of the arbitrator selected by or for that side of the disagreement together with the costs and expenses incurred by that side of the disagreement in the preparation of its case to the arbitrators. The fee and expenses of the third arbitrator selected in accordance with this Section 18.4 shall be assigned in equal parts to both sides of the disagreement, and the PARTY or PARTIES on each side of the disagreement shall assume and pay the portion of such fee and costs so assigned to that side of the disagreement. Judgment upon the award may be entered in any court having jurisdiction.

18.5 <u>Obligations to Make Payments</u>.

If a disagreement should arise concerning any plant subject which is not resolved by the Administrative Committee or the senior representatives of the PARTIES as provided in Section 18.3, then, pending the resolution of the disagreement by arbitration or litigation, CONSUMERS shall continue to operate CAMPBELL 3 and make necessary Capital Improvements in a manner consistent with this Agreement and the COOPERATIVES shall continue to make all payments required in accordance with the applicable provisions of this Agreement. Amounts paid by the COOPERATIVES during the pendency of proceedings for dispute resolution shall not be subject to refund except upon a final determination that the expenditures were made in a manner inconsistent with this Agreement.

ARTICLE 19

MISCELLANEOUS

19.1 Governing Law.

The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the State of Michigan.

19.2 Notice to PARTIES.

Unless otherwise specifically provided by other provisions of this Agreement, any notice, consent or other communication required to be made under this Agreement, shall be addressed to or made by such officer, agent, representative or employee of each PARTY as such PARTY may, from time to time, designate in writing, provided that any written notice required to be made pursuant to Sections 13.2.1 and 13.2.3 hereof shall be addressed (a) in the case of CONSUMERS, to: Consumers Power Company, 212 West Michigan Avenue, Jackson, Michigan 49201, Attention: President; (b) in the case of NORTHERN, to: Northern Michigan Electric Cooperative, Inc., Post Office Box 138, Boyne City, Michigan

49712, Attention: General Manager; and (c) in the case of WOLVERINE, to: Wolverine Electric Cooperative, Inc., Post Office Box 1133, Big Rapids, Michigan 49301, Attention: General Manager.

19.3 Article and Section Headings Not To Affect Meaning.

The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms or provisions hereof.

19.4 Counterparts.

This Agreement may be executed simultaneously in three or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

19.5 Time.

CONSUMERS and NORTHERN and WOLVERINE agree that time is of the essence in this Agreement.

19.6 Severability.

In the event that any provision of this Agreement, or the application of any such provision to any person or circumstance, shall be held invalid or unenforceable, the remainder of this Agreement, or the application of such provision to persons or circumstances other than those as to which it is held invalid or unenforceable, shall not be affected thereby.

19.7 Integration.

The terms and provisions contained in this Agreement, the Campbell 3 Back-Up Requirements Agreement and the Campbell 3 Transmission Agreement, constitute the entire agreement among CONSUMERS and NORTHERN and WOLVERINE in regard to the respective subject matters of said Agreements, and shall supersede all previous communications, representations or agreements, either oral or written, among CONSUMERS and NORTHERN and WOLVERINE with respect to the respective subject matters of said Agreements.

19.8 Computation of Time.

In computing any period of time prescribed or allowed by this Agreement, the day of the act, event or default from which the designated period of time begins to run shall not be included. The last day of this period so computed shall be included unless it is a Saturday, Sunday or legal holiday in Michigan, in which event the period shall run until the end of the next day which is neither a Saturday, Sunday nor legal holiday.

19.9 Waiver.

Any waiver at any time, by any PARTY, of its rights with respect to either or both of the other PARTIES, or with respect to any other matter arising in connection with this Agreement, shall not be considered a waiver with respect to any subsequent default or matter.

19.10 Compliance With Terms and Provisions of Covenant Deeds and Bills of Sale.

By the execution of this Agreement, NORTHERN, WOLVERINE and CONSUMERS acknowledge, accept and agree to comply with the terms and provisions contained in the Covenant Deeds and Bills of Sale as set forth in Exhibits A-1, A-2, A-3, A-4, A-5 and A-6.

19.11 Ownership and Operating Agreements Between CONSUMERS and Utilities Listed in Appendix I.

If CONSUMERS enters into an ownership and operating agreement with any of the utilities listed in Appendix I relating to the sale to such utility or utilities of an ownership interest in CAMPBELL 3, CONSUMERS shall transmit copies of such ownership and operating agreement to the COOPERATIVES. If such ownership and operating agreement contains more favorable terms and conditions (excepting any more favorable terms and conditions which must be accorded to such utility or utilities as a result of Michigan law) than those contained in this Agreement, the COOPERATIVES shall have the option to elect such more favorable terms and conditions (excepting any more favorable terms and conditions which must be accorded to such utility or utilities as a result of Michigan law) for a period of 60 days from and after the date that CONSUMERS transmits copies of such ownership and operating agreement to the COOPERATIVES, provided that the COOPERATIVES agree to all of the terms and conditions in such ownership and operating agreement (excepting any more favorable terms and conditions which must be accorded to such utility or utilities as a result of Michigan law) relating to the net monetary benefits thereunder and the respective risks undertaken by the parties to such ownership and operating agreement. The provisions of this paragraph shall apply to such ownership and operating agreement as originally entered into by CONSUMERS and such utility or utilities, but shall not apply to any amendments or supplements thereto which may be subsequently entered into by CONSUMERS and such utility or utilities. If the COOPERATIVES desire that any similar amendment or supplement be made to this Agreement, CONSUMERS shall negotiate in good faith with the COOPERATIVES in regard to such amendment or supplement, but none of the PARTIES shall be obligated to agree thereto.

19.12 Historic Places

CONSUMERS shall not, without approval in writing by the Administrator of the Rural Electrification Administration, use any portion of the funds made available to CONSUMERS by the COOPERATIVES pursuant to the terms of this Agreement to construct any facilities which will involve any district, site, building, structure or object which is included in the National Register of Historic Places, maintained by the Secretary of the Interior pursuant to the Historic Sites Act of 1935 and the National Historic Preservation Act.

19.13 Public Officials Not to Benefit

No member of or delegate to the Congress of the United States shall be admitted to any share or part of this Agreement or to benefit herefrom other than the receiving of electric service on the same terms accorded other consumers.

19.14 Equal Opportunity Clause

The following Equal Opportunity Clause is included in this Agreement only to the extent required by Executive Order No. 11246, as amended from time to time, or the Department of Labor Office of Federal Contract Compliance Regulations issued thereunder from time to time and is not intended to create any independent contractual obligations.

During the performance of this contract, CONSUMERS agrees as follows:

(a) CONSUMERS will not discriminate against any employee or applicant for employment because of race, color, religion, sex or national origin. CONSUMERS will take affirmative action to ensure that applicants are employed, and that employees are treated during employment without regard to their race, color, religion, sex or national origin. Such action shall include, but not be limited to the following: employment, upgrading, demotion or transfer; recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. CONSUMERS agrees to post in conspicuous places, available to employees and applicants for employment, notices setting forth the provisions of this non-discrimination clause.

(b) CONSUMERS will, in all solicitations or advertisements for employees placed by or on behalf of CONSUMERS, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex or national origin.

(c) CONSUMERS will send to each labor union or representative of workers with which it has a collective bargaining agreement or other contract or understanding, a notice, to be provided, advising the said labor union or workers' representative of CONSUMERS' commitments under this section, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(d) CONSUMERS will comply with all provisions of Executive Order No. 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(e) CONSUMERS will furnish all information and reports required by Executive Order No. 11246 of September 24, 1965, and by the rules, regulations and orders of the Secretary of Labor, or pursuant thereto, and will permit access to its books, records and accounts by the administering agency and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations and orders.

(f) In the event of CONSUMERS' noncompliance with the nondiscrimination clauses of this Agreement or with any of the said rules, regulations or orders, this Agreement may be cancelled, terminated or suspended in whole or in part, and CONSUMERS may be declared ineligible for further Government contracts or federally assisted construction contracts in accordance with procedures authorized in Executive Order No. 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in said Executive Order or by rule, regulation or order of the Secretary of Labor, or as otherwise provided by law.

(g) CONSUMERS will include the words "During the performance of this contract, the contractor agrees as follows:" followed by the provisions of subsections (a) through (g) of this Section (with the word "CONSUMERS" changed to "Contractor") in every subcontract or purchase order unless exempted by rules, regulations or orders of the Secretary of Labor issued pursuant to Section 204 of Executive Order No. 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. CONSUMERS will take such action with respect to any subcontract or purchase order as the administering agency may direct as a means of enforcing such provisions, including sanctions for noncompliance; provided, however, that in the event CONSUMERS becomes involved in, or is threatened with, litigation by a subcontractor or vendor as a result of such direction by the administering agency, CONSUMERS may request the United States to enter into such litigation to protect the interests of the United States.

Nothing in this section 19.14 shall be construed to prevent CONSUMERS from resisting, challenging, contesting or appealing any law, statute, regulation, license, permit, decision or order of any federal, state or local government or agency which CONSUMERS claims to be invalid, unlawful, arbitrary, capricious or otherwise improper.

19.15 Nonsegregated Facilities

The following Nonsegregated Facilities Clause is included in this Agreement only to the extent required by Executive Order 11246, as amended from time to time, or the Department of Labor, Office of Federal Contract Compliance Regulations issued thereunder from time to time and is not intended to create any independent contractual obligations.

CONSUMERS certifies that it does not maintain or provide for its employees any segregated facilities at any of its establishments, and that it does not permit its employees to perform their services at any location, under its control, where segregated facilities are maintained.

CONSUMERS certifies further that it will not maintain or provide for its employees any segregated facilities at any of its establishments, and that it will not permit its employees to perform their services at any location, under its control, where segregated facilities are maintained. CONSUMERS agrees that a breach of this certification is a violation of the Equal Opportunity Clause in this Agreement. As used in this certification, the term "segregated facilities" means any waiting rooms, work areas, restrooms and washrooms, restaurants, and other eating areas, timeclocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, color, religion, or national origin, because of habit, local custom or otherwise. CONSUMERS agrees that (except where it has obtained identical certifications from proposed subcontractors for specific time periods) it will obtain identical certifications from proposed subcontractors prior to the award of subcontracts exceeding $10,000 which are not exempt from the provisions of the Equal Opportunity Clause, and that it will retain such certifications in its files.

Nothing in this Section 19.15 shall be construed to prevent CONSUMERS from resisting, challenging, contesting or appealing any law, statute, regulation, license, permit, decision or order of any federal, state or local government or agency which CONSUMERS claims to be invalid, unlawful, arbitrary, capricious or otherwise improper.

19.16 Flood Insurance Act

Notwithstanding anything contained in this Agreement, the COOPERATIVES will be under no obligation to advance any funds to CONSUMERS to finance the construction or acquisition of any building in any area identified by the Secretary of Housing and Urban Development, pursuant to the Flood Disaster Protection Act of 1973 (the "Flood Insurance Act") or any rules, regulations or orders issued to implement the Flood Insurance Act ("Rules"), as an area having special flood hazards, or to finance any facilities or materials to be located in any such building, or in any building owned or occupied by CONSUMERS or the COOPERATIVES unless and until there has been compliance with all other conditions of this Agreement which are precedent to such advances, and the Administrator has determined, that (i) the community in which such area is located is then participating in the National Flood Insurance Program, as required by the Flood Insurance Act and any Rules and (ii) the PARTIES have obtained flood insurance coverage with respect to such building and contents as may then be required pursuant to the Flood Insurance Act and any Rules.

19.17 Environment

CONSUMERS shall comply with all applicable water and air pollution control standards and other environmental requirements imposed by federal or state statutes or regulations. In the event CONSUMERS intends or proposes to construct CAMPBELL 3 so that it will deviate significantly from the Plant as described in the Final Environmental Impact Statement issued by the REA, if any, with respect to the Plant, REA shall be afforded prompt notice of such deviations. CONSUMERS shall take all reasonable steps necessary to assure that all actions undertaken pursuant to this Agreement by CONSUMERS or others who in good faith are within its control are in compliance with the provisions of this Section.

Nothing in this Section 19.17 shall be construed to prevent CONSUMERS from resisting, challenging, contesting or appealing any law, statute, regulation, license, permit, decision or order of any federal, state or local government or agency which CONSUMERS claims to be invalid, unlawful, arbitrary, capricious or otherwise improper.

19.18 Safety

In the acquisition, construction and completion of CAMPBELL 3 pursuant to this Agreement, CONSUMERS shall comply with all applicable provisions of Federal, State and Municipal Safety laws and building and construction codes, including, but not limited to, all regulations of the Occupational Safety and Health Administration.

Nothing in this Section 19.18 shall be construed to prevent CONSUMERS from resisting, challenging, contesting or appealing any law, statute, regulation, license, permit, decision or order of any federal, state or local government or agency which CONSUMERS claims to be invalid, unlawful, arbitrary, capricious or otherwise improper.

19.19 "Kick-Backs"

In the acquisition, construction and completion of CAMPBELL 3 pursuant to this Agreement, CONSUMERS shall comply with all applicable statutes, ordinances, rules, and regulations pertaining to kickbacks. CONSUMERS acknowledges that it is familiar with the Rural Electrification Act of 1936, as amended, the so-called "Kick-Back" Statute (48 Stat. 948), and regulations issued pursuant thereto pertaining to kick-backs and 18 U.S.C. §§287 and 1001, as amended.

19.20 Buy American

(a) CONSUMERS covenants that in the expenditure of funds, under this Agreement, for the purchase of materials, articles and supplies, which are financed in whole or in part by funds obtained by the COOPERATIVES from the U.S. or through loans guaranteed by the U.S.: (1) at least one and eighty-nine one hundredths percent (1.89%) in cost of the unmanufactured articles, materials and supplies, in the aggregate, used in connection with CAMPBELL 3 shall have been mined or produced in the United States and (2) at least one and eighty-nine one hundredths percent (1.89%) in cost of the manufactured articles, materials and supplies, in the aggregate, used or to be used in connection with CAMPBELL 3 shall have been manufactured in the United States and all substantially from articles, materials or supplies mined, produced or manufactured, as the case may be, in the United States. If any article, material or supplies are partially mined, produced or manufactured in the United States (said part being hereinafter called the "American Made Portion") and partially mined, produced or manufactured somewhere other than in the United States, then only the cost of the American Made Portion shall be used in determining whether the requirements of the preceding sentence have been satisfied.

(b) At the Second Closing and from time to time thereafter, when requested by the COOPERATIVES or the Administrator of the Rural Electrification Administration, CONSUMERS shall supply the Administrator or the Party so requesting with information and documentation demonstrating that CAMPBELL 3 is being constructed in accordance with the requirements of Subsection (a) of this Section 19.20. Upon completion of construction of CAMPBELL 3 CONSUMERS shall certify to the Administrator that CAMPBELL 3 was constructed in accordance with the requirements of Section 19.20 (a).

ARTICLE 20

TERM AND TERMINATION

20.1 Termination.

This Agreement shall terminate at such time as CAMPBELL 3 is retired from service, including, without limitation: dismantling, demolishing and removal of equipment, facilities and structures; security; maintenance; and disposing of debris.

20.2 Retirement Costs.

All costs less salvage credits, if any, associated with retirement of CAMPBELL 3, including, without limitation: dismantling, demolishing and removal of equipment, facilities and structures; security; maintenance; and disposing of debris, shall be shared by the PARTIES in proportion to their respective percentage ownership interests in CAMPBELL 3. Payments for these costs less salvage credits, if any, as they are expected to be incurred, shall be made in accordance with the provisions of Section 7.3. If such salvage credits exceed such costs, the difference shall be shared by the PARTIES in proportion to their respective percentage ownership interests in CAMPBELL 3. Such obligations shall continue notwithstanding any reversion of the COOPERATIVES' respective ownership interests in CAMPBELL 3 to CONSUMERS as provided in the Covenant Deeds and/or Bills of Sale.

IN WITNESS WHEREOF, CONSUMERS, NORTHERN and WOLVERINE have caused this Agreement to be executed by their duly authorized officers, and their respective corporate seals to be affixed hereto and attested by their respective secretaries or assistant secretaries, as of the day and year first above written.

APPROVED AS TO FORM
CONSUMERS POWER COMPANY
LEGAL DEPARTMENT

CONSUMERS POWER COMPANY

Attest: ______________________
Secretary

By ______________________
Vice President

NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

Attest: Melvin Basel
Secretary

By ______________________

WOLVERINE ELECTRIC COOPERATIVE, INC.

Attest: Roy A Sturgeon

By ______________________

By John Tyndall Sec

APPENDIX A-1
DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet south of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX A-2

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The E 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

> All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:
>
> All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the <u>place of beginning</u> commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the <u>place of begining</u> of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the <u>place of beginning</u>. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

Excepting from the land described in this Appendix A-2 the land referred to as the Campbell 3 Site and described in Appendix A-1 to this Agreement.

APPENDIX B

DESCRIPTION OF PROPERTY INCLUDED IN CAMPBELL 3

CAMPBELL 3 consists of (a) the CAMPBELL 3 SITE, plus (b) all structures, equipment and facilities now or hereafter constructed or installed as a part of CAMPBELL 3 in or on the CAMPBELL 3 SITE and the CAMPBELL PLANT SITE including, but not limited to, those listed under B.1 through B.9 below, plus (c) the CAMPBELL 3 portion of Common Facilities referred to in Appendix G.

B.1 Steam Generator and Associated Equipment

B.1.1 Steam Generator

B.1.2 Coal Handling Equipment

1. Bunkers
2. Scales and Feeders
3. Pulverizers
4. Piping
5. Burners

B.1.3 Yard Coal Handling Equipment

B.1.4 Vents and Drains

B.1.5 Fly Ash Removal Piping

B.1.6 Bottom Ash Removal Piping

B.1.7 Precipitators

B.1.8 Bottom Ash Water Recirculation System

B.1.9 Combustion Air System (Including Forced Draft Fans)

B.1.10 Combustion Air Preheating System

B.1.11 Flue Gas Exhaust System

1. Breeching
2. Induced Draft Fans
3. Chimney

B.2 <u>Turbine Generator and Auxiliaries</u>

B.2.1 Turbine Generator Equipment

B.2.2 Turbine Lube Oil Purification System

B.2.3 Carbon Dioxide Distribution and Storage System

B.2.4 Hydrogen Distribution and Storage System

B.2.5 Drains

B.2.6 Condenser Vacuum System

B.2.7 Chlorination System

B.2.8 Circulating Water System

B.3 <u>Primary Mechanical Systems</u>

B.3.1 Steam Piping

1. Main Steam
2. Hot Reheat Steam
3. Cold Reheat Steam
4. Extraction Steam
5. Miscellaneous Steam

B.3.2 Feedwater System (including High Pressure Heaters)

B.3.3 Condensate System

1. Condensate Polishing
2. Condensate Seal Water
3. Low Pressure Heaters

4. Deaerator

5. Condensate Make-Up and Return

6. Drains and Vents

B.4 Primary Mechanical Support Systems

B.4.1 Auxiliary Steam System

B.4.2 Make-Up Water Treatment System

B.4.3 Waste Water Treatment System

B.4.4 Nitrogen Distribution and Storage System

B.4.5 Plant Cooling Water System

B.4.6 House Service Water System

B.4.7 Chemical Feed System

B.5 Secondary Mechanical Support Systems

B.5.1 In Plant and Control Room Fire Protection Systems

B.5.2 Site Fire Protection

B.5.3 Equipment, Floor and Roof Drains

B.5.4 Embedded Base Slab Piping

B.5.5 Potable Water System

B.5.6 Heating, Ventilating and Air Conditioning Systems

1. Plant

2. Control Room

3. Administration and Service Building

4. Chilled Water System

5. Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

B.5.7 Compressed Air Systems

1. House Service
2. Instrumentation
3. Soot Blowing

B.5.8 Temporary Steam Blowout System

B.5.9 Chemical Cleaning and Flushing System

B.5.10 Vacuum Cleaning System

B.6 <u>Instrumentation and Controls</u>

B.6.1 Process Information and Control System

B.6.2 Main Control Panels

B.6.3 Water Quality Analysis System

B.6.4 Gas Quality Monitoring System

B.7 <u>Electrical</u>

B.7.1 Generator Bus

B.7.2 6900 Volt Station and Cranking Power Electrical System

B.7.3 480 Volt Start-Up and Station Power System

B.7.4 Direct Current Power Supply

B.7.5 Conduit, Cable Trays and Duct Banks

B.7.6 Wire and Cable

B.7.7 Grounding and Cathodic Protection

B.7.8 Emergency Power System

B.7.9 Communications and Security Systems

B.7.10 Heat Tracing

B.7.11 Lighting Systems

B.8 <u>Structures and Improvements</u>

B.8.1 Permanent Railroads

B.8.2 Site Drainage

B.8.3 Turbine Building (including crane)

B.8.4 Administration and Service Building

B.8.5 Steam Generator Building

B.8.6 Control Building

B.8.7 Railroad Car Dumper and Positioner Building

B.8.8 Emergency Coal Reclaim Facilities

B.8.9 Transfer House (Coal Handling)

B.8.10 Thawing Building (Coal Handling)

B.8.11 Screenhouse and Intake Structure (Cooling Water)

B.8.12 Ash Water Recirculation Pumphouse

B.8.13 Chlorination Building

B.8.14 Precipitator Control Building

B.9 <u>Capitalized Emergency Equipment</u>

APPENDIX C
Statement of Accumulated Cost of Construction of Campbell 3 Through May 31, 1980
(Thousands of Dollars)

Contractor Expenditures	Total Work Order System Costs	Common Facility Costs: Campbell 3 Portion (included in GWO 7000)	Common Facility Costs: Non-Campbell 3 Portion (GWO 7050)	Campbell Plant Site Transmission Facilities	Cost of Constr of Campbell 3
Structures and Improvements	$ 56,067	$ 7,729	$ 4,331	0	$ 51,736
Steam Generator and Associated Equipment	119,313	4,824	1,551	0	117,762
Turbine Generator and Auxiliaries	97,516	44,010	18,370	0	79,146
Primary Mechanical Systems	19,977	0	0	0	19,977
Primary Mechanical Support Systems	5,092	340	58	0	5,034
Secondary Mechanical Support Systems	12,052	249	239	0	11,813
Instrumentation and Controls	8,479	0	0	0	8,479
Electrical	5,149	0	0	$2,374	2,775
Subtotal	$323,645		$24,549	$2,374	$296,722
Contractor Distributable Construction Costs	142,906		11,432	590	130,884[1]
Total Contractor Costs	$466,551[2]		$35,981[2]	2,964	$427,606[2]
Consumers Distributable Construction Costs					
Initial Boiler and Turbine Contract Payments	$ 1,226		0	0	$ 1,226
Materials, Engineering and Supervision	21,240		$ 1,699	0	19,541[3]
AFUDC	68,977		3,371	$ 451	65,155
Other Overheads	12,939		852	83	12,004
Totals, General Work Orders 7000 and 7050	$570,933		$41,903	$3,498	$525,532
Consumers Miscellaneous Expenditures					
Land and Land Rights - Campbell 3 Site	$ 7			0	$ 7
Land and Land Rights - Campbell 3 Portion of Campbell Plant Site	479			0	479
Transmission Circuits and Start-Up Circuits (GWO 6352, 6633, 6596, 6597, 6599, 7001, 7002 and 7004-7009)	5,491			$4,816	675
Capitalized Emergency Equipment (GWO 7003)	764			0	764
Campbell 3 Portion of Existing Common Facilities (Except Campbell 3 Portion of Campbell Plant Site)	210			0	210
Total Campbell 3	$577,884			$8,314	$527,667

[1] The Campbell 3 portion of the Contractor Distributable Construction Costs is estimated to be 91% of the Contractor Distributable Construction Costs.

[2] Total Contractor Costs are specifically identified in Consumers Total Work Order System Costs. However, classification of these costs to the various general categories are based on an estimated allocation provided by the General Contractor.

[3] The Campbell 3 portion of the materials, engineering and supervision portion of Consumers Distributable Construction Costs is estimated to be 91% of the materials, engineering and supervision portion of Consumers Distributable Construction Costs.

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APPENDIX D

Estimated Total Cost of Construction of CAMPBELL 3, Cost Incurred Through May 31, 1980 and Estimate of Remaining Cost To Be Expended (Thousands of Dollars)

		Estimated Common Facility Costs					
Contractor Expenditures	Estimated Total Work Order System Costs	CAMPBELL 3 Portion (Included in GWO 7000)	Non-CAMPBELL 3 Portion (GWO 7050)	CAMPBELL PLANT SITE Transmission Facilities	Estimated Cost of Constr of CAMPBELL 3	Cost of Constr of CAMPBELL 3 as of 5/31/80	Estimated Remaining Cost of Constr of CAMPBELL 3 To Be Expended
Structures and Improvements	$ 61,004	$ 8,067	$ 9,261	0	$ 51,743	$ 51,736	$ 7
Steam Generator and Associated Equipment	119,793	4,982	1,654	0	118,139	117,762	377
Turbine Generator and Auxiliaries	97,284	44,158	18,931	0	78,353	79,146	(793)
Primary Mechanical Systems	20,133	0	0	0	20,133	19,977	156
Primary Mechanical Support Systems	5,244	328	58	0	5,186	5,034	152
Secondary Mechanical Support Systems	12,745	206	205	0	12,540	11,813	727
Instrumentation and Controls	8,627	0	0	0	8,627	8,479	148
Electrical	5,449	0	0	$ 2,374	3,075	2,775	300
Subtotal	$330,279	$57,741	$30,109	$ 2,374	$297,796	$296,722	$ 1,074
Contractor Distributable Construction Costs	161,694		12,935	$ 1,617	147,142[1]	130,884	16,258
Total Contractor Costs	$491,973		$43,044	$ 3,991	$444,938	$427,606	$17,332
Consumers Distributable Construction Costs							
Initial Boiler and Turbine Contract Payments	$ 1,250		0	0	$ 1,250[2]	$ 1,226	$ 24
Materials, Engineering and Supervision	29,732		$ 2,379	$ 297	27,056[2]	19,541	7,515
AFUDC	82,174		5,671	680	75,823	65,155	10,668
Other Overheads	41,638		3,906	335	37,397	12,004	25,393
Totals, General Work Orders 7000 and 7050	$646,767		$55,000	$ 5,303	$586,464	$525,532	$60,932
Consumers Miscellaneous Expenditures							
Land and Land Rights - CAMPBELL 3 SITE	$ 7			0	$ 7	$ 7	0
CAMPBELL 3 Portion of CAMPBELL PLANT SITE	479			0	479	479	0
Transmission Circuits and Start-Up Circuits (GWO 6506, 6507, 6509, 7001, 7002 & 7004-7009)	5,733			$ 5,160	573	675	(102)
Capitalized Emergency Equipment (GWO 7003)	2,500			0	2,500	764	1,736
CAMPBELL 3 Portion of Existing Common Facilities	210			0	210	210	0
Total CAMPBELL 3	$655,696			$10,463	$590,233	$527,667	$62,566

[1] The CAMPBELL 3 portion of the Contractor Distributable Construction Costs is estimated to be 91% of the Contractor Distributable Construction Costs.

[2] The CAMPBELL 3 portion of the materials, engineering and supervision portion of Consumers Cistributable Construction Costs is estimated to be 91% of the materials, engineering and supervision portion of Consumers Distributable Construction Costs.

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APPENDIX E

CONSUMER'S MONTHLY PAYMENT FOR CAMPBELL 3 UNIT CAPABILITY DUE TO CONSUMERS FINANCIAL INABILITY (SECTION 5.4.2)

General:

The rate for sale of Campbell 3 Unit Capability by the COOPERATIVE to CONSUMERS based on the average of the annual fixed charge factors and COOPERATIVE'S additional average net investment as outlined below for 1979.

DETERMINATION OF BILLING -

	As of 12-31-78	As of 12-31-79	Average
Cooperative additional investment in Campbell 3 (Including AFUDC)	$	$	$
Less:			
Associated additional Accumulated Provision for Depreciation			
Cooperative's additional Net Investment in Campbell 3	$	$	$
Plus: Working Capital (1)			
Total Average Production Related Investment (C)			$
Times Fixed Charge Factor for Associated Return and Taxes			%
Cost Associated with Cooperative's Monthly Investment for Return and Associated Taxes			$
Fixed Charge Factor Component Associated with Cooperative's Additional Net Investment			$
Production Related Expenses Associated with Cooperative's Additional Investment (A)			
Depreciation Expense			
Operating Costs:			
Power Production Expenses Excluding Fuel -			
Operation Expense			
Maintenance Expense			
Administrative and General Expense			
Taxes Other Than Income:			
Property Taxes			
Payroll Taxes			
Insurance			
Liability Expense			
Fuel Expense			
Monthly Billing to Consumers for CAMPBELL 3 Unit Capability			$

(1) To include working capital on Materials and Supplies and fuel inventory only

FIXED CHARGE FACTOR:

Consumers Power Company (Fc)
Capital Structure @ 12-31-78

	Amount	Percent	Embedded Cost	Weighted Component %
Long-Term Debt	$	%	%	%
Short-Term Debt				
Preferred & Preference Stock				
Common Equity			*	
	$	%		%

Associated Tax Component
0.8964 Times Consumers' Weighted Stockholders Investment (1)
0.0241 Times Consumers' Weighted Debt (2)

Consumers' Annual Fixed Charge Factor (Fc) ______ %

Northern or Wolverine (Fp)

Northern:

Financing Cost Associated with Campbell 3(3) = %
Associated Michigan Single Business Tax Component(2)
0.0241 Times Northern's Weighted Long-Term Debt = ______

Northern's Annual Fixed Charge Factor (Fp) ______ %

Wolverine:
Financing Cost Associated with Campbell 3(3) = %
Associated Michigan Single Business Tax Component(2)
0.0241 Times Wolverine's Weighted Long-Term Debt = ______

Wolverine's Annual Fixed Charge Factor (Fp) ______ %

MONTHLY FACTOR TO BE APPLIED FOR BILLING

Return Component $\frac{(Fc + Fp)}{24} =$ ______ %

*Return on Common Equity for Electric Wholesale Rates as Authorized or accepted for filing without hearing by the Federal Energy Regulatory Commission or Succeeding Agency

(1) $\left\{ \frac{1}{(1\text{-Federal Rate})\ (1\text{-State Tax Rate})} \right\} -1 = 0.8964$

(2) $\left\{ \frac{1}{(1\text{-State Tax Rate})} \right\} -1 = 0.0241$

(3) Cost of short term debt associated with Campbell 3 prior to the Second Closing and weighted cost of long term debt associated with Campbell 3 on and after the Second Closing.

APPENDIX F

RATE FOR SALE OF CAPACITY AND ENERGY (SECTION 5.4.3)

General:

The rate for sale of Capacity and Energy shall be based upon Consumers Power Company's system costs for the period that the rate will be in effect, determined in the same manner as illustrated below for the year 1979.

Capacity Charge:

1. Net Investment	As of 12/31/78	As of 12/31/79	Average Balance		Average Balance for Rate	Avg Annual Fixed Charge Factor	Annual Capacity Costs
Total Production Plant in Service	$	$	$				
Less: Total Acc. Prov. Deprec.							
Net Production Plant							
Less: Campbell 3 Net Plant							
Net Production Excl. Campbell 3			$		$	$	$
Production Related - General, Common and Intangible Plant				x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt			
Plant Held for Future Use				x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt			
Construction Work In Progress (1)							
Less: Campbell 3 CWIP	$	$					
Net Construction Work In Progress	$	$					
Working Capital				x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt			
Total Average Production Related Investment			$		$		$

2. Production Capacity Related Expenses (2)	Budgeted 1979		Annual Capacity Costs
Operation and Maintenance		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Administrative and General		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
General Taxes			
Property		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Payroll		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Depreciation		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Insurance		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Pool Center		x Net Prod. Plt (Excl. Campbell 3) / Net Prod. Plt	
Total Expenses	$		$

3. Total Capacity Costs $

4. Annual Capacity Charge

$$\frac{\text{Total Annual Capacity Costs}}{\text{Net Demonstrated Capability (Excludes Campbell 3)}} = \$\_\_\_\_\_\_\_\_ \text{ MW}$$

(1) As authorized by Federal Energy Regulatory Commission.
(2) Functionalized for production plant

APPENDIX F
RATE FOR SALE OF CAPACITY AND ENERGY (SECTION 5.4.3)

Energy Charge:	For 1979	Annual Energy Costs
Production Energy Related -		
Fuel, Purchased Power and Net Interchange (Excludes Campbell 3)	$	$
Other Operation and Maintenance (Excluding Campbell 3)		
Total Energy Costs		$

$$\text{Energy Charge} = \frac{\text{Total Energy Costs}}{\text{Net Annual Main System Output}} = \frac{\$\_\_\_\_}{\text{MWh}}$$

Fixed Charge Factor:

Consumers Power Company
Average Capital Structure
for the Billing Year

	Amount	Percent	Embedded Cost	Return Component %
Long-Term Debt	$	%	%	%
Short-Term Debt				
Preferred & Preference Stock				
Common Equity			*	
	$			

FACTOR TO BE APPLIED FOR BILLING

Return Component	%
Associated Tax Component	
0.8964 Times Consumers' Weighted Equity(1)	
0.0241 Times Consumers' Weighted Debt(2)	
Fixed Charge Factor	%

* Return on Common Equity as Authorized by the Federal Energy Regulatory Commission or Succeeding Agency.

(1) $$\left(\frac{1}{(1\text{-Federal Rate})\,(1\text{-State Tax Rate})} \right) -1 = 0.8964$$

(2) $$\left(\frac{1}{1\text{-State Tax Rate}} \right) -1 = 0.0241$$

APPENDIX G
Common Facilities

The Common Facilities which CONSUMERS deems necessary or desirable for use in common by CAMPBELL 3 and one or more other generating units installed on the CAMPBELL PLANT SITE and the percentage portion assigned to CAMPBELL 3 and such other generating units at date of this Agreement are shown below.

Description	CAMPBELL A Portion (%)	CAMPBELL 1 & 2 Portion (%)	CAMPBELL 3 Portion (%)
New Improvements to the CAMPBELL PLANT SITE (Including Landscaping and Perimeter Fencing of the Site) (1)	1.4	45.1	53.5
Permanent Roads and Parking Lots (Existing and Constructed With CAMPBELL 3) (1)	1.4	45.1	53.5
New Cooling Water Intake and Discharge Channels (2)	-	31.4	68.6
New Cooling Water Discharge Pumphouse (3)	-	48.1	51.9
Existing Maintenance Bldg (1)	1.4	45.1	53.5
New Maintenance Building (1)	1.4	45.1	53.5
New Guard House (1)	1.4	45.1	53.5
Existing Crusher House Structure (Including All Equipment Except Existing Coal Breaker) (4)	-	45.8	54.2
New Fuel Oil Supply System (5)	-	18.9	81.1
New Ash Transport and Disposal System (6)	-	25.0	75.0
New Deep Water Intake and Discharge System (7)	-	30.3	69.7
New Vacuum Priming Systems (8)	-	24.0	76.0
New Coal Pile Runoff Collection System (9)	-	15.0	85.0
New Sanitary Waste Disposal Facilities (9)	-	50.0	50.0

Notes:

(1) The portion assigned to each column is based on the nameplate rating of the unit, or units, indicated in that column divided by the total of the nameplate ratings of CAMPBELL A, CAMPBELL 1, CAMPBELL 2 and CAMPBELL 3.

(2) The portion assigned to each column is based on the flow rate of water in each of the channels used by the unit, or units, indicated in that column divided by the total flow rate of all the water in the channels.

(3) The portion assigned to each column is based on the flow rate of water through the pumphouse used by the unit, or units, indicated in that column divided by the total flow rate of water through the pumphouse.

(4) The portion assigned to each column is based on the nameplate rating of the unit, or units, indicated in that column divided by the total of the nameplate ratings of CAMPBELL 1, CAMPBELL 2 and CAMPBELL 3.

(5) The portion assigned to each column is based on an equal allocation of direct costs of unloading facilities, storage tank and common piping between CAMPBELL 3 and CAMPBELL 1 and 2, with the balance of the estimated direct cost of the Fuel Oil Supply System allocated to CAMPBELL 3.

(6) The portion of the ash transport cost assigned to each column is based on (a) the total linear feet of pipe located on the ash trestle that carries ashes for the unit, or units, indicated in that column divided by the total linear feet of pipe located on the ash trestle times the cost of the trestle and (b) the estimated cost to install said pipe on the trestle. All costs of new ash disposal fields built for CAMPBELL 3 are allocated to CAMPBELL 3. Thus, the portion of the new ash transport and disposal system initially assigned to CAMPBELL 3 is 75.0% and to CAMPBELL 1 and 2 is 25.0%.

(7) The portion assigned to each column is based on (a) the cost of the linear feet of intake and discharge pipe in Lake Michigan that carries cooling water for the unit, or units, indicated in that column divided by the cost of the total linear feet of intake and discharge pipe in Lake Michigan and (b) the cost of the associated equipment (including, but not limited to, pumps, driving motors, associated piping, compressors, hoists and all labor and materials associated with the installation of said equipment) allocated to the unit, or units, indicated in that column divided by the cost of all of the associated equipment. The portion initially assigned to CAMPBELL 3 is 69.7% and to CAMPBELL 1 and 2 is 30.3%.

(8) Two vacuum priming systems are included, each accounting for about one half of the total cost. One system is associated with the CAMPBELL 3 condenser and is entirely allocated to CAMPBELL 3; the other is associated with the cooling water discharge pumphouse and is allocated as described in Note 3. Thus, the portion initially assigned to CAMPBELL 3 is 76% and to CAMPBELL 1 and 2 is 24%.

(9) The portion assigned to each column is based on CONSUMERS' best estimate of use of the Common Facility by the unit, or units, indicated in that column.

APPENDIX II
CONSUMER'S PAYMENT FOR PLANNED EXCESS ELECTRIC CAPABILITY (SECTION 6.6.2)

General:

The rate for sale of Planned Excess Electric Capability by the COOPERATIVE TO CONSUMERS based on the average of the annual fixed charge factors, COOPERATIVE'S Average Net Investment and the COOPERATIVE'S Planned Excess Electric Capability as outlined below for 1979.

DETERMINATION OF BILLING

	As of 12/31/78	As of 12-31-79	Average
Cooperative's Investment in Campbell 3 (Including AFUDC)	$	$	$
Less:			
Associated Accumulated Provision for Depreciation			
Cooperative's Net Investment in Campbell 3	$	$	$
Plus: Working Capital (1)			
Total Average Production Related Investment (Dp)			$
Times Fixed Charge Factor for Associated Return and Taxes			%
Cost Associated with Cooperative's Monthly Investment for Return and Associated Taxes			$
Fractional Part of Cooperative's Electric Capability and Energy Entitlement			X
Fixed Charge Factor Component Associated with Cooperative's Planned Excess Electric Capability			$
Production Related Expenses Associated with Cooperative's Planned Excess Electric Capability (A x Ccp)			
Depreciation Expense			
Operating Costs:			
Power Production Expenses Excluding Fuel -			
Operation Expense			
Maintenance Expense			
Administrative and General Expense			
Taxes Other Than Income:			
Property Taxes			
Payroll Taxes			
Insurance			
Liability Expense			
Fuel Expense			
Monthly Billing to Consumers for Cooperative's Planned Excess Electric Capability			$

(1) To include working capital on Materials and Supplies and fuel inventory only

FIXED CHARGE FACTOR:

Consumers Power Company (Fc)
Capital Structure @ 12-31-78

	Amount	Percent	Embedded Cost	Weighted Component %
Long-Term Debt	$	%	%	%
Short-Term Debt				
Preferred & Preference Stock				
Common Equity			*	
	$	%		%

Associated Tax Component
0.8964 Times Consumers' Weighted Stockholders Investment (1)
0.0241 Times Consumers' Weighted Debt (2)

Consumers' Annual Fixed Charge Factor (Fc) ______ %

Northern or Wolverine (Fp)

Northern:

Cost of Financing Associated with Campbell 3(3) = ______ %
Associated Michigan Single Business Tax Component(2)
0.0241 Times Northern's Weighted Long-Term Debt = ______

Northern's Annual Fixed Charge Factor (Fp) ______ %

Wolverine:
Cost of Financing Associated with Campbell 3(3) = ______ %
Associated Michigan Single Business Tax Component(2)
0.0241 Times Wolverine's Weighted Long-Term Debt = ______

Wolverine's Annual Fixed Charge Factor (Fp) ______ %

MONTHLY FACTOR TO BE APPLIED FOR BILLING

Return Component $\frac{(Fc + Fp)}{24}$ = ______ %

*Return on Common Equity for Electric Wholesale Rates as Authorized or accepted for filing without hearing by the Federal Energy Regulatory Commission or Succeeding Agency

(1) $\left\{ \frac{1}{(1-\text{Federal Rate})\ (1-\text{State Tax Rate})} \right\} -1 = 0.8964$

(2) $\left\{ \frac{1}{(1-\text{State Tax Rate})} \right\} -1 = 0.0241$

(3) Cost of short term debt associated with Campbell 3 prior to the Second Closing and weighted cost of long term debt associated with Campbell 3 on and after the Second Closing.

APPENDIX I

Alpena Power Company
Edison Sault Electric Company
City of Bay City
City of Charlevoix
Village of Chelsea
City of Coldwater
City of Eaton Rapids
City of Grand Haven
City of Harbor Springs
City of Hart
City of Hillsdale
City of Holland
City of Lansing
City of Lowell
City of Marshall
City of Petoskey
City of Portland
City of St. Louis
City of Traverse City
Village of Union City
City of Zeeland
Michigan Public Power Agency
Michigan South Central Power Agency
Southeastern Michigan Rural Electric Cooperative, Inc.

EXHIBIT A-1

COVENANT DEED

THIS DEED, made this ____ day of ____________, 19__, between CONSUMERS POWER COMPANY, a Michigan corporation (successor by merger to Consumers Power Company, a Maine corporation), 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), and NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC., a Michigan corporation of ____________________ ________________, Boyne City, Michigan (herein called "Northern"),

WITNESSETH:

That Consumers, for and in consideration of the sum of $__________, to it in hand paid by Northern, the receipt whereof is hereby confessed and acknowledged, has granted, bargained, sold, remised, released, aliened and confirmed, and by these presents does grant, bargain, sell, remise, alien and confirm unto Northern certain undivided interests in and to certain parcels of land and rights in land in the Township of Port Sheldon, County of Ottawa and State of Michigan, as follows:

An undivided 1.26% interest in and to land referred to as the "Campbell 3 Site" described in Appendix I which is attached hereto and made a part hereof.

An undivided 1.26% interest in and to the easement and right described in Appendix II which is attached hereto and made a part hereof.

Easement rights over land referred to as the "Campbell Plant Site" described in Appendix III, attached hereto and made a part hereof, as may be required for the construction, maintenance and operation of so much of the personal property described in Appendix IV, attached hereto and made a part hereof, as is now, or hereafter will be constructed or installed as part of Campbell Unit No. 3 in or on the land described in Appendix III.

Easement rights over land referred to as the "Campbell Plant Site", described in Appendix III, as may be required for the construction, maintenance and operation of so much of the personal property described in Appendix V, attached hereto and made a part hereof, as is now, or hereafter will be constructed or installed in or on the land described in Appendix III for use in common by Campbell Unit No. 3 and one or more other generating units installed on the land described in Appendix III.

Consumers and Northern agree that all property now or hereafter annexed to the land or constructed pursuant to the rights in land hereby conveyed shall be deemed to be personal property and not fixtures. Consumers and Northern also agree that this deed conveys an undivided interest in the land and rights in land described herein only, and that it does not convey, and there is specifically excepted from this deed, any interest in personal property, including, without limitation, personal property which would be fixtures except for the agreement contained in the first sentence of this paragraph. By way of illustration, and not by way of limitation, Consumers and Northern agree that the property described in Appendix IV and in Appendix V shall be deemed to be personal property, and no interest in said property is conveyed by this deed.

Provided, however, that the estates created by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 3, now under construction on the land referred to herein as the Campbell 3 Site, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the land and rights in land hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Northern and Wolverine Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof entitled "Transfer of Interest in or Partition of Campbell 3" which is set forth in Appendix VI attached to and made a part of this deed.

Together with all the estate, right, title, interest, claim or demand whatsoever, of Consumers, either in law or equity, of, in and to the above-bargained premises; TO HAVE AND TO HOLD the premises as before described unto Northern as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the land and rights in land described herein. And Consumers does covenant, grant, bargain and agree to and with Northern, that Consumers has not heretofore done, committed or wittingly or willingly suffered to be done or committed, any act, matter or thing whatsoever, whereby the premises hereby granted, or any part thereof, is, are or shall, or may be charged or encumbered in title, estate or otherwise howsoever, except for Lease dated January 18, 1962 with Port Sheldon Beach Association for recreational purposes; Lease dated February 27, 1975 with The Department of Natural Resources of the State of Michigan for a public boat launching facility; Lease dated November 13, 1974 with Michigan Ash Sales Company for ash sale facilities; Lease dated November 9, 1961 with the Township of Port Sheldon for boat launching; Lease dated March 6, 1976 with R. M. Alspaugh for summer residence purposes; License dated January 11, 1977 to G. Philip Dietrich and wife for landscaping purposes; License dated June 20, 1974 to United States Coast Guard for a radio antenna and equipment; rights of Michigan Bell Telephone Company to construct lines and cables; oil and gas and mineral rights outstanding in others; rights of railroad companies to construct tracks and facilities; and the rights of the public, individuals, the County of Ottawa and the Board of County Road Commisioners of the County of Ottawa in streets, roads and highways.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by ______________________, and its corporate seal to be hereunto affixed and attested by its Secretary as of the day and year first above written.

Witnesses: CONSUMERS POWER COMPANY

______________________________ By__________________________________

______________________________ Attest:

____

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

The foregoing instrument was acknowledged before me this ____ day of ___________, 19__, by ______________________________________, ______________________ of Consumers Power Company, a Michigan corporation, on behalf of the corporation.

My commission expires ______________________________________

____________________________ Notary Public, Jackson County, Michigan

APPENDIX I TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERTIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX II TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

EASEMENT FOR INTAKE AND TRANSPORATION OF WATER

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:

All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

APPENDIX III TO COVENANT DEED DATED
_______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The E 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix I to this Covenant Deed.

APPENDIX IV TO COVENANT DEED DATED
_______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

1. All structures, equipment and facilities (excepting those described in paragraph numbered 2 of this Appendix IV) which are now or hereafter will be constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix I and in or on the Campbell Plant Site as described in Appendix III, including, but not limited to, the following:

<u>Steam Generator and Associated Equipment</u>

Steam Generator
Coal Handling Equipment
    Bunkers
    Scales and Feeders
    Pulverizers
    Piping
    Burners
Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
    Breeching
    Induced Draft Fans
    Chimney

<u>Turbine Generator and Auxiliaries</u>

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

<u>Primary Mechanical Systems</u>

Steam Piping
    Main Steam
    Hot Reheat Steam
    Cold Reheat Steam
    Extraction Steam
    Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
- Condensate Polishing
- Condensate Seal Water
- Low Pressure Heaters
- Deaerator
- Condensate Make-Up and Return
- Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
- Plant
- Control Room
- Administration and Service Building
- Chilled Water System
- Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

Compressed Air Systems
- House Service
- Instrumentation
- Soot Blowing

Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit.

APPENDIX V TO COVENANT DEED DATED
_______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

Certain structures, equipment and facilities which are now or hereafter will be constructed or installed in or on the Campbell 3 Site, as described in Appendix I, in or on the easement described in Appendix II and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site as follows:

New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

Existing maintenance building.

New maintenance building.

New guard house.

The new cooling water discharge pumphouse.

The existing crusher house structure (including all equipment except existing coal breaker).

The new fuel oil supply system.

The new ash transport and disposal system.

The new deep water intake and discharge system.

The new vacuum priming systems.

The new coal pile runoff collection system.

The new sanitary waste disposal facilities.

The structures within the new cooling water intake and discharge channels.

APPENDIX VI TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

The terms used in Article 13, set forth below, have the same meaning as used in the Campbell 3 Ownership and Operating Agreement. The terms "PARTY" and "PARTIES" refer to Consumers Power Company, Northern Michigan Electric Cooperative, Inc. and Wolverine Electric Cooperative, Inc., individually or collectively where appropriate. The term "CAMPBELL 3" refers to a fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 3, to be located on the Campbell 3 Site and the Campbell Plant Site with a design nameplate turbine capability rating of 770 MW electric gross, as more specifically described in Appendices B and G attached to the Campbell 3 Ownership and Operating Agreement and including the interests in land and rights in land conveyed by this deed.

[All of Article 13 to be reproduced below]

EXHIBIT A-2

COVENANT DEED

THIS DEED, made this ____ day of ____________, 19__, between CONSUMERS POWER COMPANY, a Michigan corporation (successor by merger to Consumers Power Company, a Maine corporation), 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), and WOLVERINE ELECTRIC COOPERATIVE, INC., a Michigan corporation of ________________________ _________________, Big Rapids, Michigan (herein called "Wolverine"),

WITNESSETH:

That Consumers, for and in consideration of the sum of $__________, to it in hand paid by Wolverine, the receipt whereof is hereby confessed and acknowledged, has granted, bargained, sold, remised, released, aliened and confirmed, and by these presents does grant, bargain, sell, remise, alien and confirm unto Wolverine certain undivided interests in and to certain parcels of land and rights in land in the Township of Port Sheldon, County of Ottawa and State of Michigan, as follows:

An undivided 0.63% interest in and to land referred to as the "Campbell 3 Site" described in Appendix I which is attached hereto and made a part hereof.

An undivided 0.63% interest in and to the easement and right described in Appendix II which is attached hereto and made a part hereof.

Easement rights over land referred to as the "Campbell Plant Site" described in Appendix III, attached hereto and made a part hereof, as may be required for the construction, maintenance and operation of so much of the personal property described in Appendix IV, attached hereto and made a part hereof, as is now, or hereafter will be constructed or installed as part of Campbell Unit No. 3 in or on the land described in Appendix III.

Easement rights over land referred to as the "Campbell Plant Site", described in Appendix III, as may be required for the construction, maintenance and operation of so much of the personal property described in Appendix V, attached hereto and made a part hereof, as is now, or hereafter will be constructed or installed in or on the land described in Appendix III for use in common by Campbell Unit No. 3 and one or more other generating units installed on the land described in Appendix III.

Consumers and Wolverine agree that all property now or hereafter annexed to the land or constructed pursuant to the rights in land hereby conveyed shall be deemed to be personal property and not fixtures. Consumers and Wolverine also agree that this deed conveys an undivided interest in the land and rights in land described herein only, and that it does not convey, and there is specifically excepted from this deed, any interest in personal property, including, without limitation, personal property which would be fixtures except for the agreement contained in the first sentence of this paragraph. By way of illustration, and not by way of limitation, Consumers and Wolverine agree that the property described in Appendix IV and in Appendix V shall be deemed to be personal property, and no interest in said property is conveyed by this deed.

Provided, however, that the estates created by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 3, now under construction on the land referred to herein as the Campbell 3 Site, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the land and rights in land hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Wolverine and Northern Michigan Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof entitled "Transfer of Interest in or Partition of Campbell 3" which is set forth in Appendix VI attached to and made a part of this deed.

Together with all the estate, right, title, interest, claim or demand whatsoever, of Consumers, either in law or equity, of, in and to the above-bargained premises; TO HAVE AND TO HOLD the premises as before described unto Wolverine as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the land and rights in land described herein. And Consumers does covenant, grant, bargain and agree to and with Wolverine, that Consumers has not heretofore done, committed or wittingly or willingly suffered to be done or committed, any act, matter or thing whatsoever, whereby the premises hereby granted, or any part thereof, is, are or shall, or may be charged or encumbered in title, estate or otherwise howsoever, except for Lease dated January 18, 1962 with Port Sheldon Beach Association for recreational purposes; Lease dated February 27, 1975 with The Department of Natural Resources of the State of Michigan for a public boat launching facility; Lease dated November 13, 1974 with Michigan Ash Sales Company for ash sale facilities; Lease dated November 9, 1961 with the Township of Port Sheldon for boat launching; Lease dated March 6, 1976 with R. M. Alspaugh for summer residence purposes; License dated January 11, 1977 to G. Philip Dietrich and wife for landscaping purposes; License dated June 20, 1974 to United States Coast Guard for a radio antenna and equipment; rights of Michigan Bell Telephone Company to construct lines and cables; oil and gas and mineral rights outstanding in others; rights of railroad companies to construct tracks and facilities; and the rights of the public, individuals, the County of Ottawa and the Board of County Road Commisioners of the County of Ottawa in streets, roads and highways.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by ______________________, and its corporate seal to be hereunto affixed and attested by its Secretary as of the day and year first above written.

Witnesses: CONSUMERS POWER COMPANY

______________________________ By__________________________________

______________________________ Attest:

____

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

The foregoing instrument was acknowledged before me this ____ day of ___________, 19__, by ______________________________________, ______________________ of Consumers Power Company, a Michigan corporation, on behalf of the corporation.

My commission expires ______________________________________

_____________________________ Notary Public, Jackson County, Michigan

APPENDIX I TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX II TO COVENANT DEED DATED
_____________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

EASEMENT FOR INTAKE AND TRANSPORATION OF WATER

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:

All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

APPENDIX III TO COVENANT DEED DATED
______________, 19__ *RUNNING FROM CONSUMERS POWER COMPANY*
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The E 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix I to this Covenant Deed.

APPENDIX IV TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

1. All structures, equipment and facilities (excepting those described in paragraph numbered 2 of this Appendix IV) which are now or hereafter will be constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix I and in or on the Campbell Plant Site as described in Appendix III, including, but not limited to, the following:

Steam Generator and Associated Equipment

Steam Generator
Coal Handling Equipment
    Bunkers
    Scales and Feeders
    Pulverizers
    Piping
    Burners
Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
    Breeching
    Induced Draft Fans
    Chimney

Turbine Generator and Auxiliaries

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

Primary Mechanical Systems

Steam Piping
    Main Steam
    Hot Reheat Steam
    Cold Reheat Steam
    Extraction Steam
    Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
- Condensate Polishing
- Condensate Seal Water
- Low Pressure Heaters
- Deaerator
- Condensate Make-Up and Return
- Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
- Plant
- Control Room
- Administration and Service Building
- Chilled Water System
- Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

Compressed Air Systems
- House Service
- Instrumentation
- Soot Blowing

Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit.

APPENDIX V TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

Certain structures, equipment and facilities which are now or hereafter will be constructed or installed in or on the Campbell 3 Site, as described in Appendix I, in or on the easement described in Appendix II and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site as follows:

New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

Existing maintenance building.

New maintenance building.

New guard house.

The new cooling water discharge pumphouse.

The existing crusher house structure (including all equipment except existing coal breaker).

The new fuel oil supply system.

The new ash transport and disposal system.

The new deep water intake and discharge system.

The new vacuum priming systems.

The new coal pile runoff collection system.

The new sanitary waste disposal facilities.

The structures within the new cooling water intake and discharge channels.

APPENDIX VI TO COVENANT DEED DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

The terms used in Article 13, set forth below, have the same meaning as used in the Campbell 3 Ownership and Operating Agreement. The terms "PARTY" and "PARTIES" refer to Consumers Power Company, Wolverine Electric Cooperative, Inc. and Northern Michigan Electric Cooperative, Inc., individually or collectively where appropriate. The term "CAMPBELL 3" refers to a fossil fuel-fired steam electric generating unit, known as Campbell Unit No. 3, to be located on the Campbell 3 Site and the Campbell Plant Site with a design nameplate turbine capability rating of 770 MW electric gross, as more specifically described in Appendices B and G attached to the Campbell 3 Ownership and Operating Agreement and including the interests in land and rights in land conveyed by this deed.

[All of Article 13 to be reproduced below]

EXHIBIT A-3

BILL OF SALE

CONSUMERS POWER COMPANY, a Michigan corporation, 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), for and in consideration of the sum of $_____________ to it paid by NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC., a Michigan corporation whose address is Post Office Box 138, Boyne City, Michigan (herein called "Northern"), the receipt of which is hereby acknowledged, hereby sells and conveys unto Northern certain undivided interests, as set forth in Appendix I which is attached hereto and made a part hereof, in and to certain personal property, as follows:

> All structures, equipment and facilities as described in Appendix I, including parts and materials for the construction thereof, to the extent that title thereto was held by Consumers on [here insert the date which is the Conveyance Date].

Provided, however, that the ownership and estate conveyed by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit known as Campbell Unit No. 3, now under construction and of which said personal property is a part, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the personal property hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Northern and Wolverine Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof, entitled "Transfer of Interest in or Partition of Campbell 3".

To Have and to Hold the same unto Northern as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the personal property described herein.

SAID PERSONAL PROPERTY IS SOLD "AS IS" AND "WHERE IS." CONSUMERS MAKES NO REPRESENTATION OR WARRANTY WHATSOEVER IN THIS BILL OF SALE, EXPRESSED, IMPLIED OR STATUTORY, INCLUDING, WITHOUT LIMITATION, ANY REPRESENTATION OR WARRANTY AS TO THE VALUE, QUANTITY, CONDITION, SALEABILITY, OBSOLESCENCE, MERCHANTABILITY, FITNESS OR SUITABILITY FOR USE OR WORKING ORDER OF ANY OF SAID PERSONAL PROPERTY, NOR DOES CONSUMERS REPRESENT OR WARRANT THAT THE USE OR OPERATION OF SAID PERSONAL PROPERTY WILL NOT VIOLATE PATENT, TRADEMARK OR SERVICE MARK RIGHTS OF ANY THIRD PARTIES.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by __________________________ this ____ day of _______________, 19__.

CONSUMERS POWER COMPANY

By______________________________________

APPENDIX I TO BILL OF SALE DATED
____________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

1. An undivided 1.26% interest in all structures, equipment and facilities (excepting those described in paragraphs numbered 2, 3 and 4 of this Appendix I) which are now or hereafter will be constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix II, which is attached hereto and made a part hereof, and in or on the Campbell Plant Site as described in Appendix III which is attached hereto and made a part hereof, including, but not limited to, the following:

Steam Generator and Associated Equipment

Steam Generator
Coal Handling Equipment
    Bunkers
    Scales and Feeders
    Pulverizers
    Piping
    Burners
Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
    Breeching
    Induced Draft Fans
    Chimney

Turbine Generator and Auxiliaries

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

Primary Mechanical Systems

Steam Piping
    Main Steam
    Hot Reheat Steam
    Cold Reheat Steam
    Extraction Steam
    Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
- Condensate Polishing
- Condensate Seal Water
- Low Pressure Heaters
- Deaerator
- Condensate Make-Up and Return
- Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
- Plant
- Control Room
- Administration and Service Building
- Chilled Water System
- Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

Compressed Air Systems
- House Service
- Instrumentation
- Soot Blowing

Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The undivided interest hereinafter set forth in certain structures, equipment and facilities (excepting those referred to in paragraph numbered 3 of this Appendix I) which are now or hereafter will be constructed or installed in or on the Campbell 3 Site, as described in Appendix II, and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site.

A. An undivided 0.67410% interest in and to the structures and facilities set forth in subparagraphs A.1 through A.5:

A.1. New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

A.2. Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

A.3. Existing maintenance building.

A.4. New maintenance building.

A.5. New guard house.

B. An undivided 0.65394% interest in and to the new cooling water discharge pumphouse.

C. An undivided 0.68292% interest in and to the existing crusher house structure (including all equipment except existing coal breaker).

D. An undivided 1.02186% interest in and to the new fuel oil supply system.

E. An undivided 0.94500% interest in and to the new ash transport and disposal system.

F. An undivided 0.87822% interest in and to the new deep water intake and discharge system.

G. An undivided 0.95760% interest in and to the new vacuum priming systems.

H. An undivided 1.07100% interest in and to the new coal pile runoff collection system.

I. An undivided 0.63000% interest in and to the new sanitary waste disposal facilities.

J. An undivided 0.86436% interest in and to the structures within the new cooling water intake and discharge channels.

3. The structures, equipment and facilities which are listed below are leased by Consumers from others, and this Bill of Sale does not convey any interest in such structures, equipment and facilities:

[Here insert items leased by Consumers during the period of time covered by this Bill of Sale]

4. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit. This Bill of Sale does not convey any interest in the Campbell Plant Site Transmission Facilities.

APPENDIX II TO BILL OF SALE DATED
_______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX III TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The East 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

> All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:
>
> All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix II to this Bill of Sale.

EXHIBIT A-4

BILL OF SALE

CONSUMERS POWER COMPANY, a Michigan corporation, 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), for and in consideration of the sum of $_____________ to it paid by WOLVERINE ELECTRIC COOPERATIVE, INC., a Michigan corporation whose address is Post Office Box 1133, Big Rapids, Michigan (herein called "Wolverine"), the receipt of which is hereby acknowledged, hereby sells and conveys unto Wolverine certain undivided interests, as set forth in Appendix I which is attached hereto and made a part hereof, in and to certain personal property, as follows:

> All structures, equipment and facilities as described in Appendix I, including parts and materials for the construction thereof, to the extent that title thereto was held by Consumers on [here insert the date which is the Conveyance Date].

Provided, however, that the ownership and estate conveyed by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit known as Campbell Unit No. 3, now under construction and of which said personal property is a part, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the personal property hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Wolverine and Northern Michigan Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof, entitled "Transfer of Interest in or Partition of Campbell 3".

To Have and to Hold the same unto Wolverine as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the personal property described herein.

SAID PERSONAL PROPERTY IS SOLD "AS IS" AND "WHERE IS." CONSUMERS MAKES NO REPRESENTATION OR WARRANTY WHATSOEVER IN THIS BILL OF SALE, EXPRESSED, IMPLIED OR STATUTORY, INCLUDING, WITHOUT LIMITATION, ANY REPRESENTATION OR WARRANTY AS TO THE VALUE, QUANTITY, CONDITION, SALEABILITY, OBSOLESCENCE, MERCHANTABILITY, FITNESS OR SUITABILITY FOR USE OR WORKING ORDER OF ANY OF SAID PERSONAL PROPERTY, NOR DOES CONSUMERS REPRESENT OR WARRANT THAT THE USE OR OPERATION OF SAID PERSONAL PROPERTY WILL NOT VIOLATE PATENT, TRADEMARK OR SERVICE MARK RIGHTS OF ANY THIRD PARTIES.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by ______________________ this ____ day of ____________, 19__.

CONSUMERS POWER COMPANY

By__________________________________

APPENDIX I TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

1. An undivided 0.63% interest in all structures, equipment and facilities (excepting those described in paragraphs numbered 2, 3 and 4 of this Appendix I) which are now or hereafter will be constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix II, which is attached hereto and made a part hereof, and in or on the Campbell Plant Site as described in Appendix III which is attached hereto and made a part hereof, including, but not limited to, the following:

<u>Steam Generator and Associated Equipment</u>

Steam Generator
Coal Handling Equipment
  - Bunkers
  - Scales and Feeders
  - Pulverizers
  - Piping
  - Burners

Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
  - Breeching
  - Induced Draft Fans
  - Chimney

<u>Turbine Generator and Auxiliaries</u>

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

<u>Primary Mechanical Systems</u>

Steam Piping
  - Main Steam
  - Hot Reheat Steam
  - Cold Reheat Steam
  - Extraction Steam
  - Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
  Condensate Polishing
  Condensate Seal Water
  Low Pressure Heaters
  Deaerator
  Condensate Make-Up and Return
  Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
  Plant
  Control Room
  Administration and Service Building
  Chilled Water System
  Miscellaneous Building Heating, Ventilating and Air Conditioning Systems
Compressed Air Systems
  House Service
  Instrumentation
  Soot Blowing
Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The undivided interest hereinafter set forth in certain structures, equipment and facilities (excepting those referred to in paragraph numbered 3 of this Appendix I) which are now or hereafter will be constructed or installed in or on the Campbell 3 Site, as described in Appendix II, and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site.

A. An undivided 0.33705% interest in and to the structures and facilities set forth in subparagraphs A.1 through A.5:

A.1. New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

A.2. Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

A.3. Existing maintenance building.

A.4. New maintenance building.

A.5. New guard house.

B. An undivided 0.32697% interest in and to the new cooling water discharge pumphouse.

C. An undivided 0.34146% interest in and to the existing crusher house structure (including all equipment except existing coal breaker).

D. An undivided 0.51093% interest in and to the new fuel oil supply system.

E. An undivided 0.47250% interest in and to the new ash transport and disposal system.

F. An undivided 0.43911% interest in and to the new deep water intake and discharge system.

G. An undivided 0.47880% interest in and to the new vacuum priming systems.

H. An undivided 0.53550% interest in and to the new coal pile runoff collection system.

I. An undivided 0.31500% interest in and to the new sanitary waste disposal facilities.

J. An undivided 0.43218% interest in and to the structures within the new cooling water intake and discharge channels.

3. The structures, equipment and facilities which are listed below are leased by Consumers from others, and this Bill of Sale does not convey any interest in such structures, equipment and facilities:

[Here insert items leased by Consumers during the period of time covered by this Bill of Sale]

4. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit. This Bill of Sale does not convey any interest in the Campbell Plant Site Transmission Facilities.

APPENDIX II TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX III TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The East 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

> All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:
>
> All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix II to this Bill of Sale.

EXHIBIT A-5

BILL OF SALE

CONSUMERS POWER COMPANY, a Michigan corporation, 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), for and in consideration of the sum of $_____________ to it paid by NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC., a Michigan corporation whose address is Post Office Box 138, Boyne City, Michigan (herein called "Northern"), the receipt of which is hereby acknowledged, hereby sells and conveys unto Northern certain undivided interests, as set forth in Appendix I which is attached hereto and made a part hereof, in and to certain personal property, as follows:

> All structures, equipment and facilities as described in Appendix I, including parts and materials for the construction thereof, to the extent that title thereto was acquired by Consumers subsequent to [here insert the date which is the Conveyance Date].

Provided, however, that the ownership and estate conveyed by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit known as Campbell Unit No. 3, and of which said personal property is a part, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the personal property hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Northern and Wolverine Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof entitled "Transfer of Interest in or Partition of Campbell 3".

To Have and to Hold the same unto Northern as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the personal property described herein.

SAID PERSONAL PROPERTY IS SOLD "AS IS" AND "WHERE IS." CONSUMERS MAKES NO REPRESENTATION OR WARRANTY WHATSOEVER IN THIS BILL OF SALE, EXPRESSED, IMPLIED OR STATUTORY, INCLUDING, WITHOUT LIMITATION, ANY REPRESENTATION OR WARRANTY AS TO THE VALUE, QUANTITY, CONDITION, SALEABILITY, OBSOLESCENCE, MERCHANTABILITY, FITNESS OR SUITABILITY FOR USE OR WORKING ORDER OF ANY OF SAID PERSONAL PROPERTY, NOR DOES CONSUMERS REPRESENT OR WARRANT THAT THE USE OR OPERATION OF SAID PERSONAL PROPERTY WILL NOT VIOLATE PATENT, TRADEMARK OR SERVICE MARK RIGHTS OF ANY THIRD PARTIES.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by ________________________ this ____ day of ____________, 19__.

CONSUMERS POWER COMPANY

By______________________________

APPENDIX I TO BILL OF SALE DATED
_____________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

1. An undivided 1.26% interest in all structures, equipment and facilities (excepting those described in paragraphs numbered 2, 3 and 4 of this Appendix I) which are now constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix II, which is attached hereto and made a part hereof, and in or on the Campbell Plant Site as described in Appendix III which is attached hereto and made a part hereof, including, but not limited to, the following:

Steam Generator and Associated Equipment

Steam Generator
Coal Handling Equipment
- Bunkers
- Scales and Feeders
- Pulverizers
- Piping
- Burners

Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
- Breeching
- Induced Draft Fans
- Chimney

Turbine Generator and Auxiliaries

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

Primary Mechanical Systems

Steam Piping
- Main Steam
- Hot Reheat Steam
- Cold Reheat Steam
- Extraction Steam
- Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
- Condensate Polishing
- Condensate Seal Water
- Low Pressure Heaters
- Deaerator
- Condensate Make-Up and Return
- Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
- Plant
- Control Room
- Administration and Service Building
- Chilled Water System
- Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

Compressed Air Systems
- House Service
- Instrumentation
- Soot Blowing

Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The undivided interest hereinafter set forth in certain structures, equipment and facilities (excepting those referred to in paragraph numbered 3 of this Appendix I) which are now constructed or installed in or on the Campbell 3 Site, as described in Appendix II, and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site.

   A. An undivided 0.67410% interest in and to the structures and facilities set forth in subparagraphs A.1 through A.5:

      A.1. New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

      A.2. Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

      A.3. Existing maintenance building.

A.4. New maintenance building.

A.5. New guard house.

B. An undivided 0.65394% interest in and to the new cooling water discharge pumphouse.

C. An undivided 0.68292% interest in and to the existing crusher house structure (including all equipment except existing coal breaker).

D. An undivided 1.02186% interest in and to the new fuel oil supply system.

E. An undivided 0.94500% interest in and to the new ash transport and disposal system.

F. An undivided 0.87822% interest in and to the new deep water intake and discharge system.

G. An undivided 0.95760% interest in and to the new vacuum priming systems.

H. An undivided 1.07100% interest in and to the new coal pile runoff collection system.

I. An undivided 0.63000% interest in and to the new sanitary waste disposal facilities.

J. An undivided 0.86436% interest in and to the structures within the new cooling water intake and discharge channels.

3. The structures, equipment and facilities which are listed below are leased by Consumers from others, and this Bill of Sale does not convey any interest in such structures, equipment and facilities:

[Here insert items leased by Consumers during the period of time covered by this Bill of Sale]

4. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit. This Bill of Sale does not convey any interest in the Campbell Plant Site Transmission Facilities.

APPENDIX II TO BILL OF SALE DATED
_______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX III TO BILL OF SALE DATED
_____________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The East 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

> All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:
>
> All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix II to this Bill of Sale.

EXHIBIT A-6

BILL OF SALE

CONSUMERS POWER COMPANY, a Michigan corporation, 212 West Michigan Avenue, Jackson, Michigan (herein called "Consumers"), for and in consideration of the sum of $______________ to it paid by WOLVERINE ELECTRIC COOPERATIVE, INC., a Michigan corporation whose address is Post Office Box 1133, Big Rapids, Michigan (herein called "Wolverine"), the receipt of which is hereby acknowledged, hereby sells and conveys unto Wolverine certain undivided interests, as set forth in Appendix I which is attached hereto and made a part hereof, in and to certain personal property, as follows:

> All structures, equipment and facilities as described in Appendix I, including parts and materials for the construction thereof, to the extent that title thereto was acquired by Consumers subsequent to [here insert the date which is the Conveyance Date].

Provided, however, that the ownership and estate conveyed by this conveyance shall terminate at such time as the fossil fuel-fired steam electric generating unit known as Campbell Unit No. 3, and of which said personal property is a part, permanently ceases to be used for the generation of electric energy. Upon such termination, all right, title and interest in the personal property hereby conveyed shall automatically revert to Consumers, its successors and assigns.

This conveyance is subject to the covenants, conditions and provisions contained in a certain agreement between Consumers, Wolverine and Northern Michigan Electric Cooperative, Inc. dated as of the 15th day of August, 1980 and entitled "Campbell Unit No. 3 Ownership and Operating Agreement" (herein referred to as the "Campbell 3 Ownership and Operating Agreement") as the same may be amended or supplemented from time to time, including, but not limited to Article 13 thereof entitled "Transfer of Interest in or Partition of Campbell 3".

To Have and to Hold the same unto Wolverine as tenant in common with Consumers and such other party or parties as may have or may subsequently acquire an undivided interest in the personal property described herein.

SAID PERSONAL PROPERTY IS SOLD "AS IS" AND "WHERE IS." CONSUMERS MAKES NO REPRESENTATION OR WARRANTY WHATSOEVER IN THIS BILL OF SALE, EXPRESSED, IMPLIED OR STATUTORY, INCLUDING, WITHOUT LIMITATION, ANY REPRESENTATION OR WARRANTY AS TO THE VALUE, QUANTITY, CONDITION, SALEABILITY, OBSOLESCENCE, MERCHANTABILITY, FITNESS OR SUITABILITY FOR USE OR WORKING ORDER OF ANY OF SAID PERSONAL PROPERTY, NOR DOES CONSUMERS REPRESENT OR WARRANT THAT THE USE OR OPERATION OF SAID PERSONAL PROPERTY WILL NOT VIOLATE PATENT, TRADEMARK OR SERVICE MARK RIGHTS OF ANY THIRD PARTIES.

IN WITNESS WHEREOF, Consumers has caused this instrument to be executed by ______________________ this _____ day of ____________, 19__.

CONSUMERS POWER COMPANY

By______________________________

APPENDIX I TO BILL OF SALE DATED
_____________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

1. An undivided 0.63% interest in all structures, equipment and facilities (excepting those described in paragraphs numbered 2, 3 and 4 of this Appendix I) which are now constructed or installed as a part of Campbell Unit No. 3 in or on the Campbell 3 Site as described in Appendix II, which is attached hereto and made a part hereof, and in or on the Campbell Plant Site as described in Appendix III which is attached hereto and made a part hereof, including, but not limited to, the following:

Steam Generator and Associated Equipment

Steam Generator
Coal Handling Equipment
    Bunkers
    Scales and Feeders
    Pulverizers
    Piping
    Burners
Yard Coal Handling Equipment
Vents and Drains
Fly Ash Removal Piping
Bottom Ash Removal Piping
Precipitators
Bottom Ash Water Recirculation System
Combustion Air System (including Forced Draft Fans)
Combustion Air Preheating System
Flue Gas Exhaust System
    Breeching
    Induced Draft Fans
    Chimney

Turbine Generator and Auxiliaries

Turbine Generator Equipment
Turbine Lube Oil Purification System
Carbon Dioxide Distribution and Storage System
Hydrogen Distribution and Storage System
Drains
Condenser Vacuum System
Chlorination System
Circulating Water System

Primary Mechanical Systems

Steam Piping
    Main Steam
    Hot Reheat Steam
    Cold Reheat Steam
    Extraction Steam
    Miscellaneous Steam

Primary Mechanical Systems (Cont'd)

Feedwater System (including High Pressure Heaters)
Condensate System
- Condensate Polishing
- Condensate Seal Water
- Low Pressure Heaters
- Deaerator
- Condensate Make-Up and Return
- Drains and Vents

Primary Mechanical Support Systems

Auxiliary Steam System
Make-Up Water Treatment System
Waste Water Treatment System
Nitrogen Distribution and Storage System
Plant Cooling Water System
House Service Water System
Chemical Feed System

Secondary Mechanical Support Systems

In Plant and Control Room Fire Protection Systems
Site Fire Protection
Equipment, Floor and Roof Drains
Embedded Base Slab Piping
Potable Water System
Heating, Ventilating and Air Conditioning Systems
- Plant
- Control Room
- Administration and Service Building
- Chilled Water System
- Miscellaneous Building Heating, Ventilating and Air Conditioning Systems

Compressed Air Systems
- House Service
- Instrumentation
- Soot Blowing

Temporary Steam Blowout System
Chemical Cleaning and Flushing System
Vacuum Cleaning System

Instrumentation and Controls

Process Information and Control System
Main Control Panels
Water Quality Analysis System
Gas Quality Monitoring System

Electrical

Generator Bus
6900 Volt Station and Cranking Power Electrical System
480 Volt Start-Up and Station Power System
Direct Current Power Supply
Conduit, Cable Trays and Duct Banks
Wire and Cable
Grounding and Cathodic Protection
Emergency Power System
Communications and Security Systems
Heat Tracing
Lighting Systems

Structures and Improvements

Permanent Railroads
Site Drainage
Turbine Building (including crane)
Administration and Service Building
Steam Generator Building
Control Building
Railroad Car Dumper and Positioner Building
Emergency Coal Reclaim Facilities
Transfer House (Coal Handling)
Thawing Building (Coal Handling)
Screenhouse and Intake Structure (Cooling Water)
Ash Water Recirculation Pumphouse
Chlorination Building
Precipitator Control Building

Capitalized Emergency Equipment

2. The undivided interest hereinafter set forth in certain structures, equipment and facilities (excepting those referred to in paragraph numbered 3 of this Appendix I) which are now constructed or installed in or on the Campbell 3 Site, as described in Appendix II, and in or on the Campbell Plant Site, as described in Appendix III, for use in common by Campbell Unit No. 3 and one or more other generating units installed on the Campbell Plant Site.

   A. An undivided 0.33705% interest in and to the structures and facilities set forth in subparagraphs A.1 through A.5:

      A.1. New improvements to the Campbell Plant Site (including landscaping and perimeter fencing of the site).

      A.2. Permanent roads and parking lots (existing and constructed with Campbell Unit No. 3).

      A.3. Existing maintenance building.

A.4. New maintenance building.

A.5. New guard house.

B. An undivided 0.32697% interest in and to the new cooling water discharge pumphouse.

C. An undivided 0.34146% interest in and to the existing crusher house structure (including all equipment except existing coal breaker).

D. An undivided 0.51093% interest in and to the new fuel oil supply system.

E. An undivided 0.47250% interest in and to the new ash transport and disposal system.

F. An undivided 0.43911% interest in and to the new deep water intake and discharge system.

G. An undivided 0.47880% interest in and to the new vacuum priming systems.

H. An undivided 0.53550% interest in and to the new coal pile runoff collection system.

I. An undivided 0.31500% interest in and to the new sanitary waste disposal facilities.

J. An undivided 0.43218% interest in and to the structures within the new cooling water intake and discharge channels.

3. The structures, equipment and facilities which are listed below are leased by Consumers from others, and this Bill of Sale does not convey any interest in such structures, equipment and facilities:

[Here insert items leased by Consumers during the period of time covered by this Bill of Sale]

4. The Campbell Plant Site Transmission Facilities consisting of: The Campbell Unit No. 3 main power transformers and associated 345 kV switching facilities, bus work and structures; two 345 kV transmission circuits, each approximately 0.9 mile long, connecting the Campbell Unit No. 3 main power transformers to Consumers' Campbell 345 kV Substation; three 345 kV circuit breakers and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 345 kV Substation for said two 345 kV transmission circuits; one 138 kV transmission circuit, approximately 860 feet long, connecting the Campbell Unit No. 3 cranking transformer bank to Consumers' Campbell 138 kV Substation; and one 138 kV circuit breaker and associated switching, relaying and metering facilities, bus work and structures which constitute the terminal facilities at the Campbell 138 kV Substation for said 138 kV transmission circuit. This Bill of Sale does not convey any interest in the Campbell Plant Site Transmission Facilities.

APPENDIX II TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL 3 SITE

A parcel of land in the Northeast 1/4 of Section 16, Township 6 North, Range 16 West, Port Sheldon Township, Ottawa County, Michigan, described as beginning on the East line of said Section 16 at a point 314.50 feet South of the Northeast corner of said Section; running thence South along the East line of said Section 415.50 feet; thence West 785.0 feet; thence N 21° 10' 46" W 188.21 feet; thence North 240.0 feet; thence East 853.0 feet to the East line of said Section and the place of beginning. Said parcel of land contains 8.00 acres. Bearings are based on the East line of said Section 16 as assumed North and South.

APPENDIX III TO BILL OF SALE DATED
______________, 19__ RUNNING FROM CONSUMERS POWER COMPANY
TO WOLVERINE ELECTRIC COOPERATIVE, INC.

DESCRIPTION OF THE CAMPBELL PLANT SITE

Land in Port Sheldon Township, Ottawa County, Michigan consisting of approximately 1,020 acres described as follows:

Township 6 North, Range 16 West

Section 9

The SE 1/4.

Section 10

The S 1/2 of the S 1/2 of the NW 1/4 except the West 500 feet thereof and except that portion lying East of Hiawatha Drive;

The SW 1/4 except the West 500 feet thereof and except that part of the North 20 rods thereof lying East of Hiawatha Drive;

The SW 1/4 of the SE 1/4.

Section 15

The W 3/4 lying North of Pigeon Lake.

Section 16

The East 1/2 lying North of Pigeon Lake;

Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

Gov't Lot 2 lying East of Margaret Avenue;

The vacated portion of the Plat of Mountain Beach as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

That part of Lot 9 of the Plat of Mountain Beach, according to the recorded plat thereof lying East of the East line of relocated Helen Avenue, Lots 16, 64, 65, 66, 89, 90, 91, 92, 93, 94, 95, 99, 100, 195, 196, 197 and 220 of said Plat of Mountain Beach;

That part of the area marked as "Lake Michigan Beach" on said Plat of Mountain Beach lying S'ly of the North line of Lot 17 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 16 of said Plat of Mountain Beach, if extended W'ly to Lake Michigan;

All the vacated portion of the Plat of Port Sheldon Beach lying in the SW 1/4 as described in Order Vacating Plats by the Circuit Court for the County of Ottawa, as recorded in Liber 481 at page 457, Ottawa County Register of Deeds office;

Lot 6 of the Plat of Port Sheldon Beach according to the recorded plat thereof and that part of the area marked on said Plat of Port Sheldon Beach as "Lake Michigan Beach" lying S'ly of the North line of Lot 7 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan, and N'ly of the South line of Lot 6 of said Plat of Port Sheldon Beach, if extended W'ly to Lake Michigan.

The easement and right conveyed to Consumers Power Company by instrument dated October 4, 1978, and recorded in Liber 847 at page 809, Ottawa County records, to construct, erect, lay, maintain and operate facilities for the intake and transportation of water over, through, under and upon the following lands:

> All of the unpatented overflowed lands and lake bottom lands of Lake Michigan, belonging to the State of Michigan or held in trust by it, lying Westerly of Fractional Section 16, Township 6 North, Range 16 West, Ottawa County, Michigan, described as follows:
>
> All that part of the following described land lying Westerly of the high water mark on the Easterly shore of Lake Michigan: to find the place of beginning commence at the intersection of the North and South quarter line of said section with the East and West quarter line of said section, thence South 89° 14' West along said East and West quarter line 1236.09 feet to its intersection with a line hereinafter referred to as the Baseline, thence North 2° 12' 15" West along said Baseline 1775.31 feet to the place of beginning of this description, running thence North 2° 12' 15" West along said Baseline 590.50 feet, to a point hereinafter known as Point A, thence North 51° 30' 13" West 539.04 feet, thence South 83° 29' 47" West 3330.41 feet, thence South 6° 30' 13" East 620.00 feet, thence South 80° 14' 36" East 1250.00 feet, thence North 83° 29' 47" East on a course hereinafter known as Course B 2467.30 feet to the place of beginning. Also all that part of said lake bottom land as may lie Westerly of said high water mark, Easterly of said Baseline, Northerly of said Course B projected Easterly, and Southerly of a line projected North 83° 29' 47" East from Point A.

Excepting from the land described in this Appendix III the land referred to as the Campbell 3 Site and described in Appendix II to this Bill of Sale.

EXHIBIT B

The following are the corporate officers of Consumers Power Company and Northern Michigan Electric Cooperative, Inc, and their children, living on the date of the Campbell Unit 3 Ownership and Operating Agreement of which this Exhibit B is a part:

CONSUMERS POWER COMPANY

Officer	Children
J D Selby Chairman of the Board and President	Mrs Elizabeth Beckingham (Formerly Elizabeth Selby) Mrs Marcia Bowkowski (Formerly Marcia Selby) John D Selby, Jr Michael P Selby
J B Falahee Vice Chairman of the Board	James B Falahee, Jr Mrs Kathleen M Clifton (Formerly Kathleen Falahee) Mark H Falahee Mary V Falahee Margaret L Falahee Elizabeth A Falahee Susan M Falahee Thomas M Falahee
R C Youngdahl Executive Vice President	Mrs W F Pawlick (Formerly Karen Youngdahl) Mrs J J Smith (Formerly Ann Youngdahl) Kathryn M Youngdahl Russell C Youngdahl, Jr
W R Boris Executive Vice President	Charry D Boris Emily D Boris Percilla D Boris
S H Howell Senior Vice President	Mrs Cathy A McQuillan (Formerly Cathy Howell) Susan L Howell David A Howell Thomas M Howell

Officer	Children
J W Reynolds Senior Vice President	Thomas Reynolds Steven Reynolds David Reynolds John Reynolds Laurie Reynolds
L L Shepard Vice President	Robert Shepard Thomas Shepard Nancy Shepard
R C Lincoln Vice President	Chris A Lincoln Margaret A Lincoln Mary C Lincoln Julia A Lincoln Mark J Lincoln Ann T Lincoln Andrew J Lincoln
C R Bilby Vice President	Keith Bilby Gretchen Bilby Clay Bilby Tad Bilby
R J Fitzpatrick Vice President	Shannon E Fitzpatrick Mrs Sharon A Zwibel (Formerly Sharon A Fitzpatrick)
L B Lindemer Vice President and General Counsel	David G Lindemer Lawrence B Lindemer, Jr
J W Cook Vice President	Amy Cook Jay Cook
M D Gwinn Vice President	Maclay D Gwinn, III Deborah J Gwinn B Douglas Gwinn
R J Odlevak Vice President	Kathryn Odlevak Georgelle Odlevak Janine Odlevak Ann Odlevak Threase Odlevak
S N Spring Vice President and Controller	Robert S Spring Thomas E Spring David W Spring James M Spring Richard A Spring

Officer	Children
R B DeWitt Vice President	Frederic R DeWitt Mrs Michael Bourassa (Formerly Janet M DeWitt) Mark F DeWitt Thomas M DeWitt John G DeWitt Mrs William Crouse (Formerly Cecelia A DeWitt) Laurence R DeWitt Timothy J DeWitt Paul R DeWitt Susan J DeWitt James E DeWitt Katherine M DeWitt
G L Heins Vice President	David Heins Lawrence Heins Susan Heins Thomas Heins Patricia Heins Christopher Heins Matthew Heins
P A Perry Secretary and Assistant Treasurer	Patricia A Perry Ruth A Perry Robert P Perry Donna J Perry
R M Griswold Treasurer and Assistant Secretary	No Children
T A McNish Assistant Secretary	Joseph McNish Elizabeth McNish Thomas McNish
J H Mellinger Assistant Secretary	Richard A Mellinger, Jr
B J Sarata Assistant Secretary	No Children
D W Aldrich Assistant Treasurer	Mrs John Ward (Formerly Claudia J Aldrich) Mrs Robert Risner (Formerly Tracy E Aldrich) Steven R Aldrich

Officer	Children
R L Bayn Assistant Treasurer	Robert L Bayn, Jr Dennis L Bayn Mrs Janice M Stypula (Formerly Janice Bayn)
M S Morris Assistant Treasurer	Mrs J C Schoun (Formerly Marie A Morris)

NORTHERN MICHIGAN ELECTRIC COOPERATIVE, INC

Officers	Children
T H Cummings Jr Chairman	David Lane Cummings Mrs Carolyn Salmanzadeh (Formerly Carolyn Cummings) Peter Allan Cummings Ruth Cummings Christina Cummings Truman Elliott Cummings
W B Nordbeck Vice Chairman	Gregory Wayne Nordbeck Jeffrey Alan Nordbeck Jason James Nordbeck
Melvin Herman Basel Secretary	Steven Harold Basel Dwayne Robert Basel
Harold Emil Beldo Treasurer	Harold Wayne Beldo David Allan Beldo Leslie Emil Beldo Clifford Ward Beldo