BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 16

DOE Letter to FERC

Document Accession #: 20250616-4000 Filed Date: 06/16/2025

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

[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.

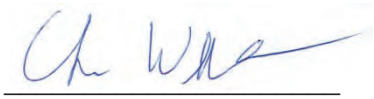
E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

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: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

Document Content(s)

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

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 Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

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.
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On behalf of Consumers Energy Company

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On behalf of Biomass Merchant Plants (BMPs)

CELESTE R. GILL, Asst. Attorney General
525 W. Ottawa Street, 7th floor
P.O. Box 30755
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

[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. 202-26-16

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

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

_____/

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:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
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Consumers Energy Company
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Jackson, Michigan 49201

On behalf of Consumers Energy Company

(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

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?

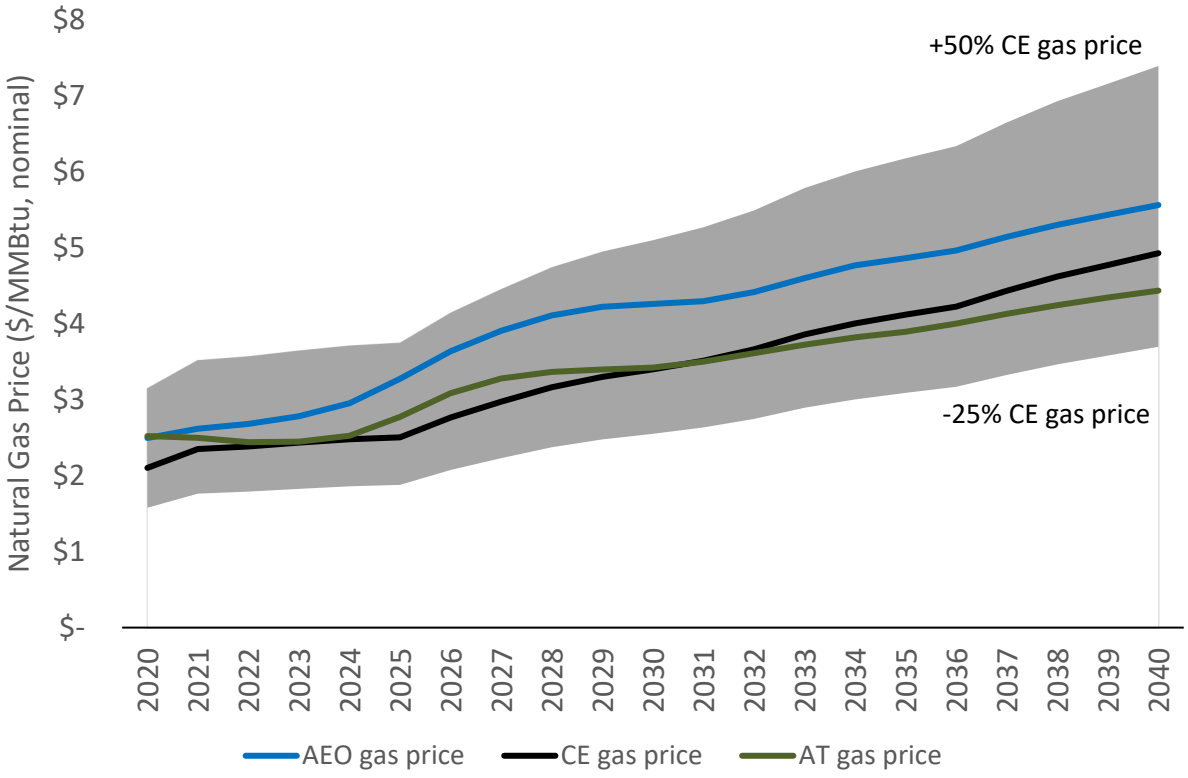
A. The Consumers Energy gas price forecast is materially below the AEO gas price forecast. The AT gas price is materially below the AEO forecast; but varies over time in the relation to the Consumers Energy gas price forecast. Through the 2020s, the Consumers Energy gas price forecast is the lowest – 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.

Figure 2: Consumers Energy Scenario Base Case Balance of Supply and Demand to Meet PRMR

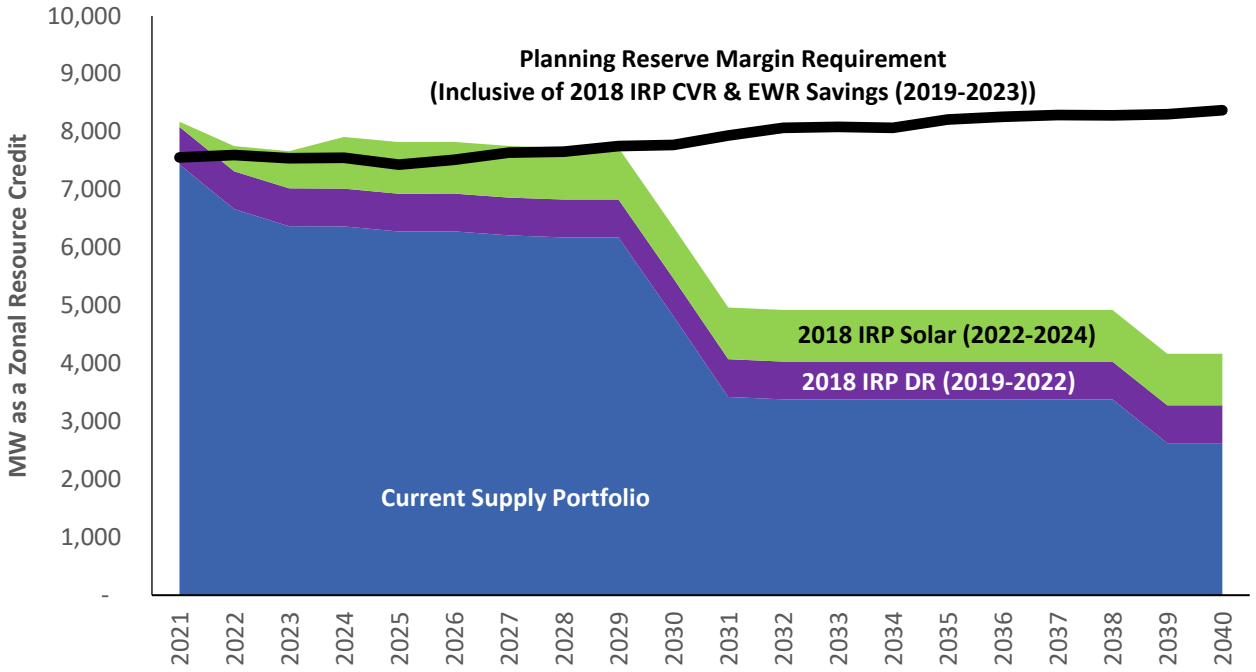
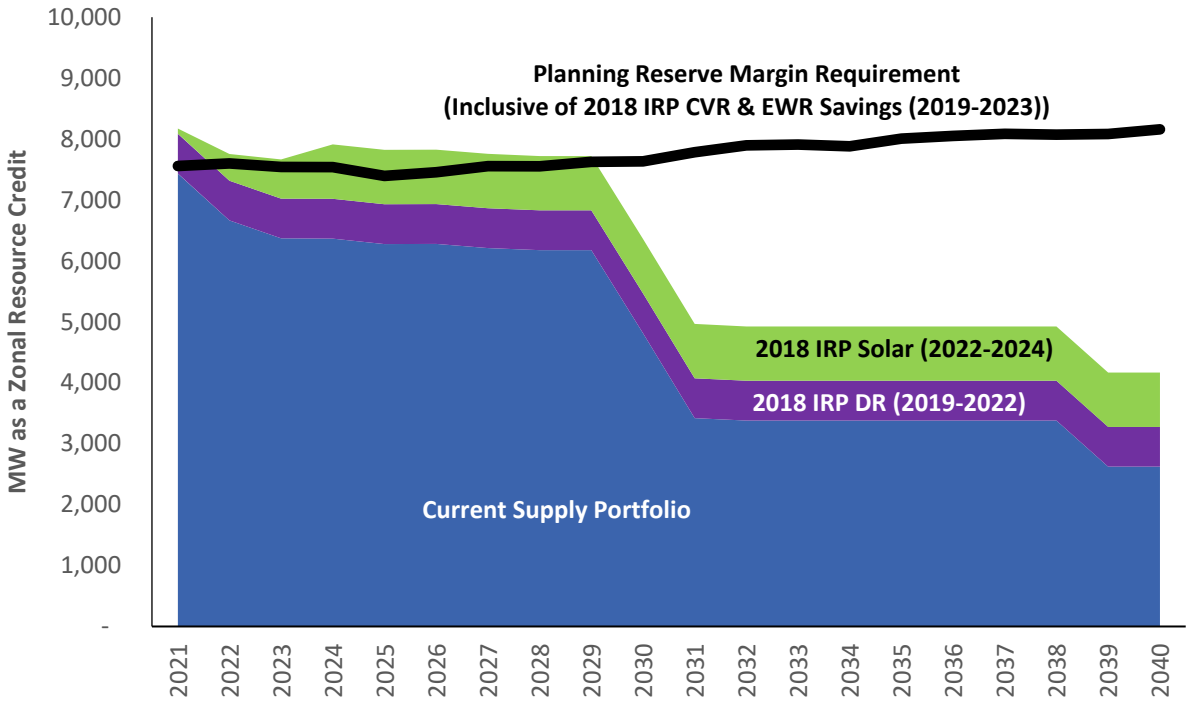


Figure 3 is the same comparison, but for the MPSC scenario base case:

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.

Demand Response

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.

New Technology Resource Selection Trends and Observations

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 solar 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.

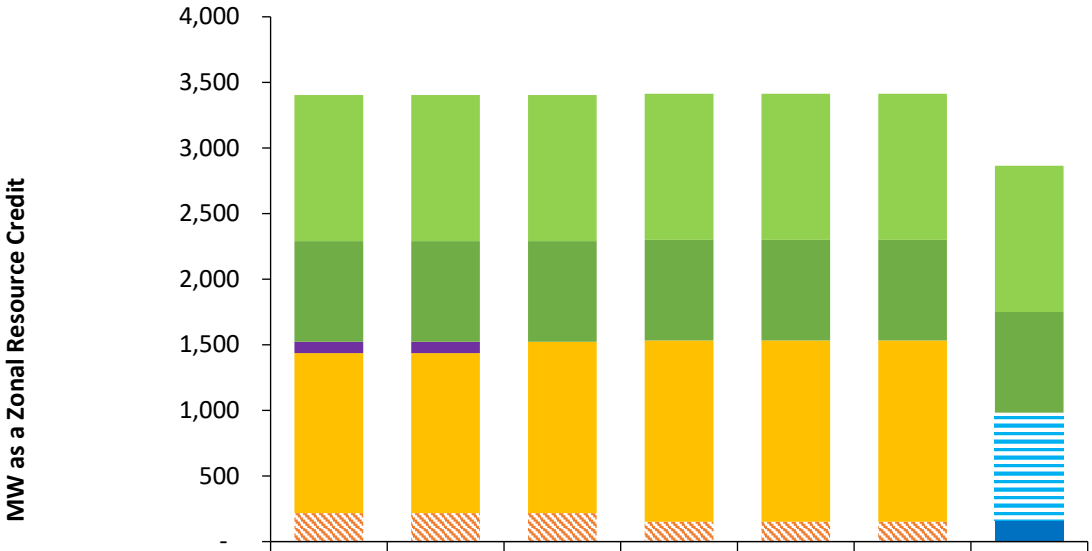
A. As discussed in Section VIII, the PCA, Portfolio 4, is a fixed resource plan. However, Portfolio 3, the optimal glide path portfolio was evaluated for the sensitivity considering retirement of the aforementioned resources. The specific build plan, Portfolio 3, corresponding to the accelerated retirement 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);

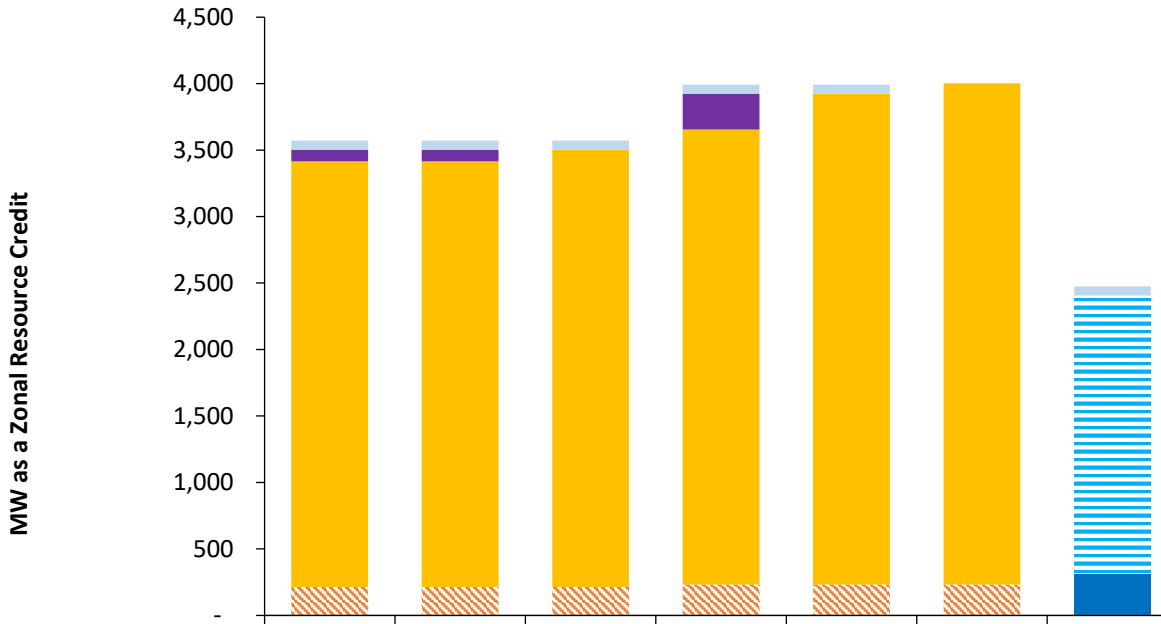
- As supported in Exhibit A-9 (STW-6), EWR was included in the portfolio, providing between 150 to 216 ZRC;

- 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.

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)
Page: 1 of 7
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
	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	-	-

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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

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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

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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
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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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)
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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
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
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Case No.: U-21090
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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
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. 202-26-16

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

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.

FOR THE ADMINISTRATOR

DATED 8/29/80

REA FORM 28a REV 5-73

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 replace-

ment 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 prop-

erly 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 Cost of Construction.

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 *Estimates and Payments of Cost of Construction After June 30, 1980.*

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 Allocation of Contractor Distributable Construction Costs and the Materials, Engineering and Supervision Portion of Consumers Distributable Construction Costs Accumulated under Work Order System.

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 New York Times 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 Test Electric Energy.

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 Electric Capability Not Needed By the COOPERATIVES.

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 CONSUMERS' Payment for COOPERATIVES' Planned Excess Electric Capability in CAMPBELL 3.

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 COOPERATIVES' Unplanned Excess Electric Capability in CAMPBELL 3

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 per-

formance 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), produc-

tion 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 Conditions Precedent to the Second Closing.

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 Maintenance of Each COOPERATIVE'S Portion of the Fuel Stockpile

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 Transfer of Ownership Interests in CAMPBELL 3 by One PARTY to One or Both of the Other PARTIES.

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 repre-

sentatives 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 Disagreement Prior to Commercial Operation.

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 Disagreement After Commercial Operation.

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 Obligations to Make Payments.

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: _____
Secretary

By _____

WOLVERINE ELECTRIC COOPERATIVE, INC.

Attest: _____

By _____

By _____

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 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 begining 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 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 Turbine Generator and Auxiliaries

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 Primary Mechanical Systems

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 Instrumentation and Controls

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 Electrical

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 Structures and Improvements

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 Capitalized Emergency Equipment

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
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)

Contractor Expenditures	Estimated Total Work Order System Costs	Estimated Common Facility Costs CAMPBELL 3 Portion (Included in GWO 7000)	Estimated Common Facility Costs 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 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 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

Total Annual Capacity Costs / Net Demonstrated Capability (Excludes Campbell 3) = $ _____ / 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		$

$$\text{Energy Charge} = \frac{\text{Total Energy Costs}}{\text{Net Annual Main System Output}} = \$ _____ / \text{MWh}$$

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 H

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 Cep)			
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:

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 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:

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 0.33705% 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

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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.

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The W 3/4 lying North of Pigeon Lake.

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Gov't Lot 1 except the North 200 feet lying West of Margaret Avenue;

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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.

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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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 21

Bleckman Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of CONSUMERS ENERGY COMPANY'S application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.

Case No. U-21816

Volume II

** PUBLIC **

_____/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Jonathan F. Thoits, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Monday, April 21, 2025, at 9:05 AM Eastern.

APPEARANCES:

ANNE M. UITVLUGT, ESQ.
GARY A. GENSCH, JR., ESQ.
Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201
On behalf of Consumers Energy Company

HEATHER M.S. DURIAN, ESQ.
MONICA M. STEPHENS, ESQ.
Assistant Attorney Generals
7109 West Saginaw Highway
Lansing, Michigan 48917
On behalf of Michigan Public Service Commission Staff

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of **CONSUMERS ENERGY COMPANY's** application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023.	)	Case No. U-21816

DIRECT TESTIMONY

OF

MARC R. BLECKMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

November 2024

Q. Please state your name and business address.

A. My name is Marc R. Bleckman, 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 the Executive Director of Financial Planning and Analysis.

Q. What are your current responsibilities?

A. My responsibilities include preparation of the monthly forecasts, annual budgets, and long-term financial plans for Consumers Energy and CMS Energy, the parent company of Consumers Energy. As a part of my role, I conduct financial analyses and studies required for making various strategic decisions such as equity issuance, sale of businesses, and new investments. I assist the Chief Financial Officer in preparing the presentations for Board of Directors meetings, quarterly earnings calls, investor meetings, and industry conferences. My responsibilities also include preparation of the Renewable Energy Plan ("RE Plan") forecast model, which is a responsibility I have continued to assume from a previously held position.

Q. Please describe your educational background and describe any positions held prior to your current position.

A. I received a Master of Business Administration Degree with a Finance concentration from the Katz Graduate School at the University of Pittsburgh in 2002. Upon receiving this degree in May 2002, I joined Ford Motor Company as a Financial Analyst. During my seven years of employment at Ford, I worked in various finance roles throughout the company, including Assembly Operations, Powertrain Operations, Ford Motor Credit, and

the General Auditor's Office. My responsibilities within these organizations included, but were not limited to, forecasting of and variance reporting on, all Income Statement and Balance Sheet line items, as well as business process auditing. In July 2009, I left Ford Motor Company to join Consumers Energy as a Principal Financial Analyst in the Company's Risk, Strategy, and Financial Advisory Services group. My responsibilities in this role included, but were not limited to, supporting the financial analysis and forecasting of the Company's renewable energy development plans, as well as conducting the Company's Enterprise Risk Management Program. In September 2012, I took on the role of Manager of Earnings Analysis in the Company's Financial Planning and Analysis Group. I assumed my current position as the Executive Director of Financial Planning and Analysis in February 2016.

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

A. Yes. I provided testimony in:

- Case No. U-16543, the Company's 2011 RE Plan Amendment;
- Case No. U-16581, the Company's 2011 RE Plan biennial review;
- Case No. U-17301, the Company's 2013 RE Plan biennial review;
- Case No. U-17752, the Company's 2015 RE Plan Amendment;
- Case No. U-17792, the Company's 2015 RE Plan biennial review;
- Case No. U-18231, the Company's 2017 RE Plan biennial review;
- Case No. U-20322, the Company's 2018 Gas Rate Case;
- Case No. U-20483, the Company's 2018 RE Plan cost reconciliation;
- Case No. U-20650, the Company's 2019 Gas Rate Case;

- Case No. U-20697, the Company's 2020 Electric Rate Case;
- Case No. U-20722, the Company's 2019 RE Plan cost reconciliation;
- Case No. U-20963, the Company's 2021 Electric Rate Case;
- Case No. U-20984, the Company's 2021 RE Plan Amendment;
- Case No. U-21009, the Company's 2020 RE Plan cost reconciliation;
- Case No. U-21148, the Company's 2021 Gas Rate Case;
- Case No. U-21197, the Company's 2021 RE Plan cost reconciliation;
- Case No. U-21224, the Company's 2022 Electric Rate Case;
- Case No. U-21308, the Company's 2022 Gas Rate Case;
- Case No. U-21352, the Company's 2022 RE Plan cost reconciliation;
- Case No. U-21374, the Company's 2023 RE Plan Amendment;
- Case No. U-21389, the Company's 2023 Electric Rate Case;
- Case No. U-21490, the Company's 2023 Gas Rate Case;
- Case No. U-21549, the Company's 2023 RE Plan cost reconciliation; and
- Case No. U-21585, the Company's 2024 Electric Rate Case.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to address the calculation of the costs of compliance (total and incremental) of Consumers Energy's 2024 RE Plan Amendment, as well as the projection of the RE Plan regulatory balance.

Q. Are you sponsoring any exhibits?

A. I am sponsoring the following exhibits:

Exhibit A-4 (MRB-1)	Incremental Costs of Compliance projection; and
Exhibit A-5 (MRB-2)	Regulatory Balance projection.

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

A. Yes.

INCREMENTAL COSTS OF COMPLIANCE

Q. Please describe the Incremental Costs of Compliance ("ICC") calculation.

A. Section 47 of Public Act 235 of 2023 ("Act 235") sets forth the ICC calculation. Based on my understanding of the definition, I have calculated the ICC in Exhibit A-4 (MRB-1) as the sum of the costs in lines 2 through 6, less the sum of the cost offsets in lines 8 through 13 and 15.

Q. Is the calculation of the ICC for this filing performed in the same manner as it was for the approved 2023 RE Plan Amendment in Case No. U-21374?

A. Yes, with one additional item of note. The Financial Compensation Mechanism ("FCM") on any new Purchased Power Agreements ("PPA") is a new addition to this RE Plan filing in accordance with MCL 460.1047(2)(a)(v)(C). FCM costs are included in Line 4 (Costs of Power Purchase Agreement Contracts). The collection of the FCM costs related to PPAs are included in line 10 (Costs Recovered under the PSCR (Transfer Rate) or line 12 (Additional Revenue as Determined by the Commission). There is zero net impact to the regulatory liability/(asset) related to the FCM as collections assumed in the RE Plan are perfectly offset with assumed costs in any given year.

Q. Please describe how the costs in Exhibit A-4 (MRB-1), line 2, are calculated.

A. This line reflects all projected financing and capital costs (including a Return on Common Equity ("ROE") investment), depreciation expense, general taxes, and Operation and Maintenance ("O&M") expenses associated with the Company's investment to build renewable energy systems as part of its RE Plan to comply with 2008 PA 295("Act 295"),

as amended by 2016 PA 342 ("Act 342") and Act 235 and the investments made to provide resources for customers electing to participate in a Voluntary Green Pricing Program ("VGP"), as authorized by Section 61 of Act 342.

Q. Please describe how the forecasted return on investment associated with the Company's investment in renewable energy systems is calculated.

A. The Company forecasts the annual capital expenditures which it expects will be required to achieve its plan to build, own, and operate new renewable energy systems as part of its RE Plan. The resulting average annual balances for the Company's Construction Work in Progress ("CWIP") and net plant in service for new renewable energy systems are summed and multiplied by the Company's approved pre-tax Weighted Average Cost of Capital ("WACC") for each time frame. Consistent with prior RE Plan Amendments, the WACC applied to assets intended to comply with the initial 15% renewable standard reflects a 10.7% ROE, in accordance with MCL 460.1047(1) that states that capital costs for those projects "…shall remain fixed at the rate of return and debt-to-equity ratio that was in effect when the electric provider's amended renewable energy plan that first included the renewable energy system was approved by the commission."

Consistent with MCL 460.1047(1), average balances to comply with the 15% renewable standard will be multiplied each month by the pretax authorized WACC from the prevailing electric rate case order, adjusted for the following:

(1) The authorized Long-Term Debt and Common Equity amounts are revised to maintain the debt/equity ratio from the Order in Case No. U-15245, which was the Order in effect when the Company's RE Plan was approved on May 26, 2009; and

(2) The authorized ROE portion of the WACC will remain fixed at 10.70%, which was the ROE authorized by the Commission in its Order in MPSC Case No. U-15245 that established the general rates in effect when the Company's RE Plan was originally approved; and

- A modified WACC of 7.70% based on Case No. U-21389, was multiplied by average CWIP balances for the entire RE Plan period in the filing.

For any VGP assets and assets constructed to comply with Act 235 included in this RE Plan Amendment, those assets were calculated based directly on the prevailing approved capital structure from Case No. U-21389. A WACC of 7.25% based on Case No. U-21389 was multiplied by the average CWIP balances for these assets for the entire RE Plan period in the filing.

Q. Have you included Allowance for Funds Used During Construction ("AFUDC)" in the CWIP balances?

A. No. AFUDC cost recovery is not required as Act 295 allows for recovery of financing costs on CWIP balances.

Q. How did the Company calculate the forecasted capital expenditures for new renewable energy systems?

A. The Company's capital forecast for assets to meet the 15% renewable energy credit ("REC") portfolio standard ("RPS") is based on projects already approved by the MPSC. All of these assets are fully operational and include the following facilities:

- Lake Winds Energy Park ("Lake Winds") is a 100.8 MW, 56 turbine wind facility that commenced commercial operation in November 2012. The total cost of Lake Winds was approximately $235 million. Lake Winds is projected to have a levelized cost of approximately $110/MWh.

- Cross Winds Energy Park ("Cross Winds") is a 111 MW, 62 turbine wind facility that commenced commercial operation in December 2014. Capital costs for Cross Winds were approximately $247 million. Cross Winds is projected to have a levelized cost of approximately $59/MWh.

- Cross Winds Energy Park II ("Cross Winds II") added 44 MW and 19 turbines with capital costs of $85 million. Cross Winds II has been operational since January 2018 and is projected to have a levelized cost of approximately $45/MWh.

- Cross Winds Energy Park III ("Cross Winds III") added an additional 76 MW and 33 turbines with capital costs of $141 million. Cross Winds III has been in operation since December 2019 and is projected to have a levelized cost of approximately $46/MWh.

- Gratiot Farms Wind Project ("Gratiot") is a 150 MW, 60 turbine wind facility that commenced commercial operation in December 2020 with capital costs of approximately $260 million. Gratiot is projected to have a levelized cost of approximately $52/MWh.

- Crescent Wind Project ("Crescent") is a 166 MW, 60 turbine wind facility that commenced commercial operation in February 2021 with capital costs of approximately $246 million. Crescent is projected to have a levelized cost of approximately $48/MWh.

- Heartland Wind Project ("Heartland") is a 198 MW, 72 turbine wind facility that commenced commercial operation in December 2024 with capital costs of $358 million. Heartland is projected to have a levelized cost of approximately $53/MWh.

In this filing, the Company plans to build, own, and operate approximately 3.8 GW of solar facilities and 2.8 GW of wind facilities to comply with renewables standards in Act 235. 690 MW of the solar capacity is comprised of the following four Integrated Resource Plan ("IRP") solar projects that will be incorporated in the RE Plan starting in 2025:

- Muskegon Solar is a 250 MW facility with projected capital costs of approximately $360 million, a projected commercial operation date of January 2026, and a projected levelized cost of approximately $52/MWh.

- Spring Creek is a 140 MW facility with projected capital costs of approximately $250 million, a projected commercial operation date of June 2026, and a projected levelized cost of approximately $57/MWh.

- Washtenaw Solar is a 150 MW facility with projected capital costs of approximately $235 million, a projected commercial operation date of January 2027, and a projected levelized cost of approximately $72/MWh.

- Mustang Mile is a 150 MW facility with projected capital costs of approximately $280 million, a projected commercial operation date of January 2027, and a projected levelized cost of approximately $57/MWh.

The remaining solar and wind assets to comply with Act 235 are based on wind and solar proxy levelized cost models. These models are escalated for future years based on an inflation rate of approximately 2%. As a result, construction costs and levelized cost increase as commercial operation dates of proxy facilities move further into the future. Further discussion for these economic assumptions can be found in the testimony of Company witness Kenneth D. Johnston. Capital expenditures for assets intended to comply with Act 235 are projected to total approximately $13 billion ($7 billion of solar and $6 billion of wind).

In this filing, the Company also includes plans to build, own, and operate nearly 1.1 GW of VGP solar facilities, all located in the state of Michigan. 731 MW are based on the following specifically identified projects:

- SunFish II Solar Project ("SunFish") is a 309 MW solar facility that is currently under construction with a projected commercial operation date of April 2026. Capital costs for SunFish are projected to be approximately $460 million. SunFish is projected to have a levelized cost of approximately $51/MWh.

- Karn Solar Energy Project ("Karn") is an up to 85 MW solar facility that is currently under construction with a projected commercial operation date of January 2027. Capital costs for Karn are projected to be approximately $145 million. Karn is projected to have a levelized cost of approximately $59/MWh.

- A proxy 117 MW solar facility with a projected commercial operation date of January 2028. Capital costs for this facility are projected to be approximately $225 million with a projected levelized cost of approximately $60/MWh.

- A proxy 220 MW solar facility with a projected commercial operation date of January 2028. Capital costs for this facility are projected to be approximately $380 million with a projected levelized cost of approximately $59/MWh.

The remaining MW of VGP solar facilities is based on a proxy levelized cost model that is considered competitive with recent pricing for solar power purchase agreements. This model is escalated for future years with an inflation factor of approximately 2%. As a result, construction costs and levelized cost are increased as the year of commercial

operation date of each proxy facility moves further out in the future. The proxy facilities are expected to have a net capacity factor of 23%, capital costs of approximately $685 million in total, and a subscription rate ranging from $73.66 to $82.95. All VGP solar facilities are expected to qualify for 100% Production Tax Credits ("PTCs") and the total capital costs for all 1,000 MW is expected to be approximately $1.9 billion. Further support for these economic assumptions can be found in the testimony of Company witness Kenneth D. Johnston. The Company's RE Plan Amendment assumes these projects, once operational, will be 100% subscribed by VGP customers and will not have costs recovered through PSCR transfer costs.

In this filing, the Company also plans to expand on the existing Solar Gardens Community Solar Program by building, owning, and operating an incremental 5.5 MW of solar facilities. This expansion is projected based on proxy facilities with a net capacity factor of 24%, capital costs of approximately $15 million, and a levelized cost of approximately $98/MWh. The filing assumes the Solar Gardens expansion will consist of 2.5 MW in 2026 and additional 3.0 MW in 2030. All of the Solar Gardens expansion is expected to qualify for 100% PTCs and to be ultimately fully subscribed. Further details on the planned expansion of this program can be found in the testimony of Company witnesses Zachary S. Cole and Johnston.

Q. How did the Company calculate the forecasted recovery of capital invested for new wind energy systems?

A. The Company calculated the forecasted recovery of its in-service wind project capital by utilizing the actual depreciation rate for each asset currently in service and assumed that expense based on that rate will continue through the end of the RE Plan period. For wind

project capital not yet in service, a composite depreciation rate based on existing wind project assets was utilized for forecast future depreciation. The depreciation rate utilized for future wind capital is 3.35%.

Q. What depreciation rate does the Company propose to utilize for the solar facilities?

A. The solar depreciation rate assumed in the RE Plan is 3.97%, which is the prevailing depreciation rate for solar projects, as approved in Case No. U-20849.

Q. How did the Company project the O&M expenses for the new renewable energy systems?

A. The O&M projections for the existing renewable facilities are projected primarily on the Company's experience in operating several existing wind facilities which are already operational under the RE Plan. An inflation factor of approximately 2% is utilized for O&M expense beyond 2029. The O&M expenses for the new wind and solar facilities are estimated based on the cost projections in levelized cost models for projects currently under construction or proxy facilities in the future.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 3, are calculated.

A. This line includes the estimated costs from purchases of RECs. The Company would multiply the projected number of RECs purchased against the current or projected rate. This line reflects $14 million in this RE Plan Amendment for the purchase of RECs. Further discussion for these assumptions can be found in the testimony and exhibits of Company witness Chibuzo C. Obikwelu.

Q. Please describe how the costs in Exhibit A-4 (MRB-1), line 4, are calculated.

A. The values in this line include the following:

- Forecasted costs associated with contracts for long-term renewable energy supply under Renewable Energy Purchase Agreements ("REPAs"). These

costs are incurred as revenue requirements when the associated generation is used for Act 295 and Act 235 compliance. These projected costs are detailed in the testimony and exhibits of Company witness Cole.

- Forecasted costs associated with PPAs from the Company's VGP program. These projected costs are detailed in the testimony and exhibits of Company witness Cole.

- Forecasted costs associated with the FCM applied to all applicable PPAs. These projected costs are detailed in the testimony and exhibits of Company witness Cole.

- Forecasted costs associated with return applied to the REC inventory balance. The contracts and REC inventory balance are discussed further in the direct testimony and exhibits of Company witness Obikwelu.

Q. Please describe how the costs in Exhibit A-4 (MRB-1), line 5, are calculated.

A. These costs are an estimate of the fees required to be paid in order to access and utilize the Michigan Renewable Energy Certification System ("MIRECS"). These projected costs are detailed in the testimony and exhibits of Company witness Obikwelu.

Q. Please describe how the costs in Exhibit A-4 (MRB-1), line 6, are calculated.

A. This line includes estimated costs associated with the Company's Advanced Renewable Tariff, as part of the Company's Experimental Advanced Renewable Program ("EARP")-Solar and EARP-Anaerobic Digestion ("EARP-AD"). These projected costs are detailed in the testimony and exhibits of Company witness Cole.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 8, are calculated.

A. This line includes the estimated revenues from potential sales of RECs. The Company would multiply the projected number of RECs sold against the current or project rate. The Company has not made and does not project any future REC sales.

Q. Please describe how the values in Exhibit A-4 (MRB-1), line 9, are calculated.

A. This line includes the estimated value of federal tax credits designed to promote the development of renewable energy. The tax benefits reflected in line 9 are gross up for taxes in order to be a true offset to customer pre-tax revenue requirements.

Q. Has the Company received, or does the Company expect to receive, any federal tax credits or incentives?

A. Yes. As approved in Case No. U-16581, the Company elected to receive the Section 1603 Cash Grant ("Cash Grant") in lieu of tax credits for the 2012 Lake Winds project. In December 2010, Congress extended the Cash Grant Program by one year, to be available to projects for which physical construction commenced in 2011 and commercial operation began by December 31, 2012. The Lake Winds construction and commercial operation schedule met these new timing requirements, and a Cash Grant was received from the United States Treasury Department in January 2012 in the amount of approximately $69.2 million.

The Company is also receiving and will continue to receive PTCs for other wind facilities to meet the 15% RPS, which includes Cross Winds, Gratiot, Crescent, and Heartland. Additionally, all additional solar and wind facilities planned for the VGP Program, the expansion of the Solar Gardens program, and to comply with Act 235 also now qualify for PTCs under the Inflation Reduction Act ("IRA") of 2022. PTCs are projected to be available for every project in the RE Plan and estimated to increase for inflation through the RE Plan period. The RE Plan projects all assets will qualify for 100% PTCs except for Heartland, which currently receives a 110% PTC as the project qualifies

for the 10% Energy Community Tax Credit Bonus. The total of all federal tax credits assumed in the RE Plan is approximately $8.9 billion.

Q. Please describe how the values in Exhibit A-4 (MRB-1), line 10, are calculated.

A. This line includes the portion of the total costs of compliance that the Company has included as part of its transfer rate forecast and expects to recover as part of its Power Supply Cost Recovery ("PSCR") Plan cases. This is calculated by multiplying the projected energy generated from the Company's proposed projects and REPAs by the calculated Transfer Prices. Further discussion of these costs, including calculation of the Transfer Prices, can be found in the direct testimony and exhibits of Company witness Zachery S. Cole. It is projected that the PSCR transfer rate for unsubscribed facilities can once again be capped at the project's respective levelized cost of energy starting on January 1, 2034 to ensure the RE Plan remains in a regulatory liability position at the end of the RE Plan period included in this filing. However, the balance of the regulatory liability or asset will continue to be monitored for final determination of when the PSCR transfer rate cap can be restored. This will be discussed in greater detail later in my testimony.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 11, are calculated.

A. This line includes the projected revenue from wholesale renewable energy sales. Consistent with prior RE Plan amendments, the Company does not project to enter into wholesale renewable energy sale agreements.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 12, are calculated.

A. This line refers to any additional revenue considered by the Commission to be attributable to Act 235 compliance. The Company utilizes this line to forecast the subscription

payments received from participating customers in the Company's Solar Garden Program and the Renewable Energy Program. These revenues are detailed in the testimony and exhibits of Company witnesses Cole and Johnston.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 13, are calculated.

A. This line may be used in the future for any RE Plan-related revenues that could be mistakenly recovered in general rates. There are no costs included in this line for the years projected in this RE Plan.

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 15, are calculated.

A. The values in this line include the Company's forecast of interest paid to customers on projected regulatory liability balances or Company return on projected regulatory asset balances as included on Exhibit A-5 (MRB-2), line 3. Interest on a regulatory liability balance is charged at the Company's short-term average borrowing rate. The Company projects its average short-term borrowing rate for 2024 to be 5.2%, which is equal to the year-to-date average through August and a monthly estimate of 5.0% for the remainder of 2024. Short-term borrowing rates are projected to be 4.26% in 2025, 3.12% in 2026, 2.93% in 2027, 2.93% in 2028, and 2.89% thereafter. Projected rates from 2025 through 2029 are based on the average of projections from Blue Chip and IHS Markit. The 2029 projection is carried forward through the remaining years in the RE Plan period. The Company has applied the projected pre-tax WACC against projected regulatory asset balances, in accordance with MCL 460.1047(3).

Q. Please describe how the revenues in Exhibit A-4 (MRB-1), line 16 are calculated.

A. Line 16 is the ICC for the RE Plan Amendment. It is the sum of all the costs in lines 2 through 6, less the sum of all cost offsets in lines 8 through 13 and line 15.

Q. Please summarize the calculation of the regulatory balance performed in Exhibit A-5 (MRB-2).

A. The calculation begins with the annual ICC from line 14 of Exhibit A-4 (MRB-1), with a positive number indicating that there are incremental costs generated in the year to be collected. A net positive ICC in a given year would either decrease a liability balance or increase an asset balance.

Line 2 indicates if there is a surcharge to be collected. As described in the testimony of Company witness Johnston, however, the Company is not proposing a surcharge in this case. Therefore, there are no values in this line.

Line 3 calculates the amount of short-term interest or pre-tax WACC applied in the year if the balance is in a liability or asset position, respectively. Interest on a liability balance would decrease the liability balance while pre-tax WACC return would increase the asset position.

Line 4 shows the annual increase (more liability) or decrease (less liability) to the balance while line 5 shows the projected year-end balance.

Q. Please describe the projected regulatory balance associated with the Company's RE Plan, as calculated in Exhibit A-5 (MRB-2).

A. Due to the Company's position in this case to not implement a surcharge, the Company projects the balance to move from its current liability position into an asset position, peaking at approximately $0.6 billion in the early 2030s driven by the Company-owned portion of the RPS compliance portfolio. The Company then proposes that, in 2034, it will be in position to cap the PSCR transfer rates for its owned assets at the respective project LCOEs, and that this cap will have the effect of lowering the regulatory balance back into

a liability position by the late 2030s where it will remain for the rest of this RE Plan period. The projected regulatory liability is projected to also peak at approximately $0.7 billion in the early 2040s and is projected to be approximately $0.3 billion at the end of this RE Plan period. The Company sees this as a balanced approach which does not go too far into either a liability or asset position while minimizing upfront customer costs by not implementing a surcharge.

Q. Does this complete your direct 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. 202-26-16

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

Exhibit 22

Hahn 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 approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2025	))))))	Case No. U-21592

DIRECT TESTIMONY

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2024

Q. Please state your name and business address.

A. My name is Joshua W. Hahn, 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. In what capacity are you employed?

A. I am a Principal Engineer in the Electric Supply Operations and Power Supply Cost Recovery ("PSCR") Section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please briefly describe your educational background.

A. I received a Bachelor of Science Degree in Mechanical Engineering in 2008 from Michigan Technological University.

Q. Please describe your business and professional experience.

A. I joined the Company's Transactions and Resource Planning Department in January 2010. I was responsible for analysis of Financial Transmission Rights ("FTRs") and acquisition of FTRs through monthly and annual allocations and auctions, as well as maintaining the Company's short-term Load and Market Price models using MetrixIDR™. In June 2012, I assumed primary responsibilities for the maintenance of the PROMOD IV Full Transmission production cost model. From January to September 2013, I assumed temporary responsibility for maintenance of the PROMOD IV production cost model and all analyses developed using the tool, including all fuel and purchased and net interchange forecasting. Later, in June 2015, I was again assigned responsibility to maintain the model and perform all analyses developed using PROMOD IV. In January 2016, I assumed

responsibilities as the primary Production Cost modeler for near-term fuel and purchased power expenses using PROMOD IV. In 2022 PROMOD IV was replaced with the Aurora Production Costing Program as the primary production cost model.

Q. What are your present responsibilities and duties as a Principal Engineer?

A. I am responsible for modeling and analysis of fuel and purchased and net interchange power costs that are used in developing the PSCR Plan and updating the PSCR factor. Additionally, I am responsible for generation unit outage analyses.

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-17918-R 2016 PSCR Reconciliation case;
- Case No. U-18402 2018 PSCR Plan case;
- Case No. U-20068 2017 PSCR Reconciliation case;
- Case No. U-20219 2019 PSCR Plan case;
- Case No. U-20202 2018 PSCR Reconciliation case;
- Case No. U-20525 2020 PSCR Plan case;
- Case No. U-20220 2019 PSCR Reconciliation case;
- Case No. U-20649 2020 Voluntary Green Pricing case;
- Case No. U-20802 2021 PSCR Plan case;
- Case No. U-20526 2020 PSCR Reconciliation case;
- Case No. U-21009 2020 Renewable Energy Reconciliation case;
- Case No. U-21048 2022 PSCR Plan case;
- Case No. U-20803 2021 PSCR Reconciliation case;

- Case No. U-21257 2023 PSCR Plan case;
- Case No. U-21049 2022 PSCR Reconciliation case;
- Case No. U-21423 2024 PSCR Plan case; and
- Case No. U-21258 2023 PSCR Reconciliation case.

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

A. The purpose of my direct testimony is to forecast fuel costs, as well as purchased and net interchange power needed to fulfill the Company's system requirements for 2025 through 2029 in support of the Company's 2025 PSCR Plan.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-7 (JWH-1)	Monthly Summary of the Projected 2025 Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2025 through 2029 of Fuel and Purchased and Net Interchange Power Expenses; and
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2025 Rates.

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

A. Yes.

POWER SUPPLY COSTS

Q. What are the Company's forecasts of 2025 costs of fuel and purchased and net interchange power?

A. These forecasts are shown in Exhibit A-7 (JWH-1), pages 1 through 3.

Q. Do you consider the forecast data set forth in Exhibit A-7 (JWH-1) to be a reasonable forecast for 2025?

A. Yes. This plan was developed using an economic dispatch computer program which is used to produce the Company's budget and operating forecasts for purchased and net interchange power, and fuel costs. This 2025 forecast was produced using up-to-date assumptions and data reviewed by the responsible departments and input to the program. The results have been reviewed for reasonableness and for consistency with input and assumptions.

Q. Did you use the same economic dispatch program for this case as was used for the Company's 2024 PSCR Plan case, Case No. U-21423?

A. Yes. The Aurora Production Costing Program was used in both cases.

Q. Please further describe Exhibit A-7 (JWH-1).

A. This exhibit details the Company's planned sources and corresponding costs of energy to be supplied in 2025. Total system requirements (expressed in units of MWh) are shown on page 1, line 14; the corresponding annual non-capacity-related expenses, including fuel and variable purchased and net interchange PSCR expense (expressed in units of thousands of dollars) are shown on page 1, line 27. Page 1, lines 28 through 33, present the fixed and capacity-related costs included in PSCR expense. Additional information about page 1, lines 28 through 33, is provided in more detail below. Page 1, line 43, presents the expenses attributed to the Long-Term Industrial Load Retention Rate. Page 1, line 44, presents the expenses attributed to the Large Economic Development Rate.

Exhibit A-7 (JWH-1), pages 2 and 3, summarize the Purchased and Interchange ("P&I") power quantity and expense projected to be incurred by the Company in 2025.

These pages detail the expenses associated with purchases from (i) Power Purchase Agreements ("PPAs") and (ii) utilities and markets shown in the "Purchased (PPAs)" and "Net Interchange" categories shown on Exhibit A-7 (JWH-1), page 1.

Line 35 on Exhibits A-7 (JWH-1) and A-8 (JWH-2) are taken from Company witness Daniel S. Alfred's Exhibit A-1 (DSA-1).

Lines 36 and 38 through 40 on Exhibits A-7 (JWH-1) and A-8 (JWH-2) are taken from Company witness Nathan J. Hoffman's Exhibits A-12 (NJH-3) through A-15 (NJH-6).

Q. Explain how PSCR costs were allocated between capacity-related and non-capacity-related costs.

A. Certain expenses represent the cost of capacity in the form of purchasing Zonal Resource Credits ("ZRCs"). The actual price paid is allocated to each month for which the purchase applies. These expenses are shown on Exhibit A-7 (JWH-1), page 1, line 28.

For most Company-owned resources, there is no capacity-related cost included in PSCR expense. The exception to this generalization is presented on Exhibit A-7 (JWH-1), page 1, line 29, where the capacity component of the Transfer Price associated with the Company's owned renewable resources for which recovery is sought under Public Act 295 of 2008, complementing the energy (or non-capacity-related) component of the Transfer Price presented on Exhibit A-7 (JWH-1), page 1, line 19.

PPAs include both capacity-related and non-capacity-related costs. Some PPAs define payments as "capacity" payments, "fixed energy" payments, and "variable energy" payments. Capacity payments and fixed energy payments are generally regarded as fixed costs because they are expected to be incurred regardless of the amount of energy delivered

by the supplier. Non-capacity or variable energy payments generally reflect the cost of fuel and variable labor and, thus, vary depending on the amount of energy delivered.

Other PPAs provide for a single price to be paid for each unit of energy to be delivered based on a capacity price and a combined fixed and variable energy price. Generally, these types of contracts are not dispatchable by the Company and, thus, the amount to be paid is likely limited by the physical capability of the supplying facility. In these instances, we have estimated the fixed energy costs based on the rates upon which the contracts were originally modeled.

Other PPAs included in the Company's rates are based upon the amount of cost allowed to be transferred from the Company's Incremental Cost of Compliance in accordance with Public Act 295 of 2008 to its PSCR costs. To estimate the amount of capacity, fixed energy, and variable energy expense associated with these transfer expenses, the Company used the energy and capacity schedules approved by the Commission that resulted in the transfer expenses.

Non-capacity or variable cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on Exhibit A-7 (JWH-1), page 1, line 25. Capacity or fixed cost-related expense for the Company's PPAs (excluding the Palisades PPA) is shown on page 1, lines 31 and 32.

Q. How were these figures derived?

A. They were derived from Aurora, which simulates the dispatch of the Company's generating resources and P&I power resources to meet projected customer electric demand requirements. Exhibit A-7 (JWH-1), pages 1 through 3, show the monthly results for 2025, which were then totaled to obtain the annual results that are also shown on Exhibit A-8

(JWH-2), along with the years 2026 through 2029. The main inputs to Aurora were projected system loads, unit heat rates, maintenance schedules, unit random outage rates, fuel costs, unit net demonstrated capabilities, and P&I power availability and costs. The model used by Aurora is structured to align as closely as possible with the way that the Midcontinent Independent System Operator, Inc. ("MISO") operates and administers the Energy Market.

Q. Who provided you with the input data relating to projected system loads and system generation requirements?

A. The system load and system generation requirements data was provided to me by Company witness Eugène M.J.A. Breuring. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. Does Company witness Breuring's system load and system generation requirements data include any new rates which require adjustment on your Exhibit A-7 (JWH-1)?

A. Yes. Mr. Breuring's system load and system generation requirements data included deliveries for the Large Economic Development ("LED") rate. The energy rate for LED is based upon the MISO Real-Time Locational Marginal Price ("LMP") and the monthly transmission charge is based on the incremental transmission charges applicable to the load served under the LED rate. As such, I have created a specific line to reflect the relevant and cost amounts for the LED rate on line 44 of Exhibits A-7 (JWH-1) and A-8 (JWH-2).

Q. What was the source of your input information for fuel costs?

A. Coal, oil, and natural gas costs were provided by Company witness Kevin C. Lott. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

Q. Who provided input information for the Consumers Energy generating units?

A. That information was provided by Company witness Nathan J. Hoffman. His direct testimony and exhibits set forth and explain the relevant assumptions and calculations.

CONSUMERS ENERGY-OWNED GENERATING UNITS

Q. Are there any major changes to Consumers Energy's owned units for this PSCR Plan case?

A. Yes. There is one new owned solar unit, and five additional solar blocks are included and modeled as five units. The first "block" unit is a 300 MW block with a Commercial Operation Date ("COD") of 6/1/2028. This block is modeled as 100% PPA. The second unit is a 198.6 MW block with a COD of December 1, 2027, which is modeled as 74% owned and 24% PPA. The third unit is a 190 MW block with a COD of December 1, 2027, which is modeled as 50% owned and 50% PPA. The fourth unit is a 500 MW block with a COD of December 1, 2028, which is modeled as 50% owned and 50% PPA. The fifth unit is a 500 MW block with a COD of December 1, 2029, which is modeled as 50% owned and 50% PPA.

Spring Creek Solar was added as a new 140 MW owned solar unit with a COD of June 1, 2026.

The following CODs were revised for owned Solar units.

- Mustang Mile 150 MW unit: 12/31/2026
- Washtenaw 150 MW unit: 12/7/2026
- Muskegon 250 MW unit: 12/31/2025
- Sunfish 309 MW unit: 3/31/2026
- Karn 85 MW unit: 12/31/2026

Q. Please describe any limiting factors that could restrict the economic dispatch of the Jackson natural gas-fueled combined cycle plant.

A. Based on the Company's current operation of the unit in compliance with the state air permit,[1] the 7EA combustion turbine cannot exceed 113.1 tons of Nitrogen Oxide ("NO_x") emissions in a rolling 12-month period and each LM6000 combustion turbine cannot exceed 95 tons of NO_x emissions in a rolling 12-month period.[2]

Q. How has the limitation of NO_x emissions been modeled in AURORA?

A. Economic dispatch of the Jackson Plant has been limited using a price adder on the incremental cost of energy when necessary to comply with the state air permit. For modeling purposes, the Jackson Plant has been limited to an annual generation amount that corresponds to the annual NOx limit.

Q. Is this a reasonable approach to limiting the economic dispatch of the facility?

A. Yes. By including the dispatch fee in the incremental cost of energy, the commitment and dispatch of the facility will respond to price signals, which will result in increased production during periods of relatively high energy prices compared to the variable cost to produce power and decreased production during periods of relatively low energy prices compared to the variable cost to produce power.

Q. Have any costs associated with owned plants been removed?

A. Yes. The projected replacement power costs associated with certain limited outages expected at the Ludington pumped storage plant in 2025 that would likely be avoided but for Toshiba workmanship have been removed from the forecasted Net Interchange, excluding ZRC on line 26 of Exhibits A-7 (JWH-1) and A-8 (JWH-2).

[1] Renewable Operating Permit ("ROP") No.: MI-ROP-N6626-2014a.
[2] Page 20 of 56 and page 25 of 56 in ROP No.: MI-ROP-N6626-2014a.

Q. Does this filing include any other Ludington outages to address the Toshiba workmanship?

A. Yes. The Company's five-year PSCR forecast includes several additional outages that are currently planned for the purpose of correcting Toshiba's workmanship on certain components at Ludington. In subsequent PSCR plan cases, the Company anticipates that it will remove projected replacement power costs associated with those outages from the projected costs for the relevant plan year, consistent with what it has done for 2025 in this case. The Company notes that it also expects additional Ludington outages in the next five years, to address and correct Toshiba workmanship, which are not reflected in the current five-year PSCR forecast included in this case. Those anticipated additional outages are not yet included in the modeled forecast because the Company has not yet finalized the dates and exact projected duration of those outages. Once the outage dates and lengths are finalized, the model will reflect the outages in future filings, however there are currently no plans for any of these outages, beyond the outages mentioned in the previous question and answer above, to be conducted in 2025.

POWER PURCHASE AGREEMENTS

Q. On Exhibit A-7 (JWH-1), page 1, line 12, you use the term "Purchased (PPAs)." Please explain that term.

A. That term refers to forecasted purchases of energy and capacity from PPAs. A list of the entities from which power is projected to be purchased for the years 2025 through 2029 is found on Exhibit A-9 (JWH-3), pages 1 through 5, under the headings "Existing Energy-Only Agreements," "Green Generation Program Agreements," "Existing Energy &

Capacity Agreements," and "Renewable Energy Plan Agreements." This exhibit also outlines the rates for such purchases and the current duration of the contracts.

Q. How were purchases from the suppliers listed on Exhibit A-9 (JWH-3) estimated?

A. The estimate was made using one of two methods:

(1) For non-dispatchable suppliers, the Company has a history of deliveries, so the historical monthly average was used; and

(2) For dispatchable suppliers, the respective PPAs state that the Company can vary the hourly energy purchased from the supplier from a stated minimum up to the amount of capacity available at the time, not to exceed the contract capacity. These suppliers were dispatched in a manner similar to the Company's own generating units and interchange sources.

Q. Are there any changes in the existing sources of purchased power for this PSCR Plan case?

A. Yes. The following contract COD were updated:

- Thorn Lake Solar: 20MW unit terminated
- Addle Solar: 20MW unit terminated
- Olivier Solar: 20MW unit terminated
- Puck Solar: 20MW unit terminated
- Sunbelievable Solar: 12MW unit terminated

The Company has also incorporated placeholder units into the model to estimate the energy and capacity expenses associated with any contract in which the contract termination date falls within the planning period but said contract would qualify for a new contract, as provided for in Case Nos. U-18090 and U-20165.

Q. Are there any new sources of purchased power for this PSCR Plan case?

A. Yes. As described above in the Consumers Energy-Owned Generating Units section, five additional solar blocks are included.

Three storage units and one solar unit have also been added into the model:

- Tibbits Energy Storage 100 MW unit: COD of 5/31/2025
- Century Oaks Energy Storage 200 MW unit: COD of 6/1/2026
- Voyager Energy Storage 100 MW unit: COD of 5/31/2027
- Freshwater Solar 300 MW unit: COD of 6/1/2027

Q. Are the Renewable Resource Program suppliers included in this PSCR Plan case?

A. Yes, the Renewable Resource Program (or Green Generation Program) approved by the Commission in its January 25, 2005 Order in Case No. U-14843 is modeled in this case. The suppliers are comprised of wind and landfill gas units and are shown on Exhibit A-9 (JWH-3), listed under the category of Green Generation Program Agreements. The energy charge for all the Green Generation contracts that are recoverable in the PSCR plan utilize the average PSCR rate for the year.

Q. What is the impact of the Reduced Dispatch Agreements ("RDAs") in place with Cadillac, Genesee, Grayling, and the Ada Cogeneration Facility?

A. As in last year's PSCR Plan, Case No. U-21257, the Cadillac, Genesee, and Grayling wood-fueled units are dispatched on the cost of production based on a wood price, instead of the 12-month rolling average coal price that is the contract dispatch price for these units. The RDAs for the wood-fired units were most recently included as Exhibit A-38 (DFR-12) in Case No. U-15001-R. The Ada RDA is priced based on an annual fixed price of natural gas, as approved in Case No. U-16045. The projected hold-harmless amount resulting from this dispatch is $578,000 and the projected customer benefit (offset to PSCR) is $1,439,000. These amounts are included as credits on Exhibit A-7 (JWH-1) and Exhibit A-8 (JWH-2), page 1, line 25, and page 3, line 56.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 57.

A. Line 57 represents the projected payments to the Biomass Merchant Plants in excess of the Company's avoided cost as required under Public Act 286 of 2008 and the Commission's August 11, 2009 Order in Case No. U-16048.

NET INTERCHANGE POWER

Q. On Exhibit A-7 (JWH-1), page 1, line 13, you use the term "Net Interchange." Please explain this term.

A. This term refers to purchases from, and sales to, other entities for energy and capacity. The details are shown on Exhibit A-7 (JWH-1) and on Exhibit A-8 (JWH-2), pages 2 and 3. Exhibit A-7 (JWH-1), page 2, lines 46 and 47, detail the energy received and Exhibit A-7 (JWH-1), page 2, lines 50 through 51, detail the energy delivered. Exhibit A-7 (JWH-1), page 3, lines 54 and 55, detail the costs for energy received and page 3, lines 59 through 60, detail the revenues for energy delivered.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 60.

A. Page 3, line 60, represents revenue from the sale of capacity, although no sale of capacity is projected in this case.

Q. Does the Company have agreements with other entities that involve transactions classified as "Purchased and Interchange Power"?

A. No.

Q. Does this complete your direct testimony?

A. Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 23

Bilsback 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.
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Consumers Energy Company
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Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

STATE OF MICHIGAN
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.	))))))))	Docket No. U-21090 Administrative Law Judge Sally L. Wallace

DIRECT TESTIMONY OF

KELSEY BILSBACK, PHD

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER, THE ECOLOGY CENTER, THE UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

October 28, 2021

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I. Name and Qualifications

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

A. My name is Kelsey Bilsback. I am a senior scientist at Physicians, Scientists, and Engineers for Healthy Energy. My business address is 1440 Broadway, Suite 750, Oakland, California, 94612.

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

A. The Environmental Law & Policy Center, the Ecology Center, the Union of Concerned Scientists, and Vote Solar.

Q. Can you please summarize your educational background?

A. I received a BA in Physics from Boston University and a PhD in Mechanical Engineering from Colorado State University. My PhD dissertation was focused on characterizing emissions from residential cookstoves.

Q. Can you please summarize your work experience?

A. My work experience is outlined in detail in my resume, Exhibit CEO-6 (KB-1). Briefly, I am a senior scientist at PSE Healthy Energy with a background in mechanical engineering and atmospheric science. My expertise is in emissions, aerosols, air pollution, air quality measurements, atmospheric modeling, and data and statistical analyses. Prior to joining PSE, I was a postdoctoral researcher in Atmospheric Science at Colorado State University, where my work was focused on implementing process-level models for secondary organic aerosol in atmospheric models and using chemical-transport models to assess the air quality, health, and climate impacts of energy transition policies. Additionally, as a graduate researcher at Colorado State University, I characterized the health- and climate-relevant properties of smoke from the solid-fuel cookstoves, which are primarily used in

low- and middle-income countries. This research included a series of large-scale laboratory- and field-testing campaigns. I have authored 17 peer-reviewed publications, reviewed journal publications and scientific proposals for funding agencies, and presented at various national and international scientific conferences such as the American Association for Aerosol Research, the American Geophysical Union, and the International Society for Environmental Epidemiology.

Q. Have you ever testified before this Commission?

A. No.

Q. Have you testified in other proceedings?

A. No.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit CEO-6 (KB-1) – Resume of Kelsey Bilsback
- Exhibit CEO-6 (KB-2) – COBRA metrics for Karn, JH Campbell, and Dearborn

II. Purpose and Summary

Q. What is the purpose of your Testimony?

A. The purpose of my testimony is to quantify the public health and equity dimensions of gas, coal, and biomass-fired power plants in Consumers Energy Company's ("Consumers" or the "Company") Integrated Resource Plan (IRP). Specifically, I estimated the *total* emissions, *rate* of emissions, and fine particulate matter ($PM_{2.5}$)-related health impacts of nine total plants. These included the existing Dan E Karn, JH Campbell, Jackson Generating Station, and Zeeland Generating Station plants as well as the plants that Consumers has proposed buying (i.e., Kalamazoo River Generating Station, Livingston

Generating Station, New Covert Generating Project, and Dearborn Industrial Generation). Further, I estimated the emissions and health impacts of Midland Cogeneration Venture, since Consumers has a significant purchasing agreement with this plant. Finally, I calculated the *total* emissions and emissions *rates* for the following biomass plants that Consumers has a purchasing agreement with: Cadillac Renewable Energy, Genesee Power Station, Grayling Generating Station, Viking Energy of Lincoln, and Hillman Power Company.

Q: What process do you use to reach these estimates?

A: First, I compiled emissions of fine particulate matter ($PM_{2.5}$) and $PM_{2.5}$ precursors from each of the power plants from various sources. Then, I used two different scientific models to translate the emissions from each of these plants to the $PM_{2.5}$-related health impacts. I analyzed *total* health impacts, the *rate* of health impacts, and the *spatial* distribution of the health impacts from each of the power plants. The latter provides insights into whether certain communities may be disproportionately impacted by air pollution from the nine plants discussed above (see Elena Krieger's testimony). Finally, based on these analyses, I discuss the potential benefits and risks of the Consumers IRP.

Q. Please summarize your conclusions.

A. My conclusions are summarized below:

- Retiring the Campbell and Karn coal plants will save 40 to 90 lives per year and $430-$972 million per year. Campbell is particularly important to retire because it leads to greater total health impacts than any other individual plant.
- Dearborn, Kalamazoo, Livingston, and Covert—plants Consumers plans to purchase—lead to 9-19 mortalities per year ($93-209 million per year). Dearborn is particularly

harmful, because it is responsible for most of these mortalities (7.5-17 premature mortalities per year) and Dearborn leads to *per capita* health impacts that are 2.5 times higher for Black people than the overall population.

- All nine of the plants examined in detail here have substantial health impacts. The only way to eliminate the health impacts of these plants is to rapidly transition to zero-emissions energy sources (e.g., solar, wind, hydroelectric) coupled with energy storage. The health metrics described above are given on an annual basis. Thus, for every year that these fossil fuel power plants are retired early, health benefits are realized.
- Finally, biomass power plants are likely to have higher air pollutant emissions *rates* per unit energy produced. Thus, while these plants may be considered to have climate benefit under certain policies, they may have substantial health impacts and should be considered from a public health perspective.

III. Background and Methods

Q: What are the public health hazards, risks, and impacts associated with fossil fuel combustion in power plants?

A: Fossil fuel combustion in power plants emits air pollutants that have negative impacts on air quality and human health.[1,2,3] Air pollutants from fossil fuel plants include primary air pollutants, i.e., constituents that are emitted directly by the power plant, and precursors of

[1] Murray, C. J., Aravkin, A. Y., Zheng, P., Abbafati, C., Abbas, K. M., Abbasi-Kangevari, M., ... & Borzouei, S. (2020). Global burden of 87 risk factors in 204 countries and territories, 1990–2019: a systematic analysis for the Global Burden of Disease Study 2019. *The Lancet*, *396*(10258), 1223-1249. https://doi.org/10.1016/S0140-6736(20)30752-2

[2] Vohra, K., Vodonos, A., Schwartz, J., Marais, E. A., Sulprizio, M. P., & Mickley, L. J. (2021). Global mortality from outdoor fine particle pollution generated by fossil fuel combustion: Results from GEOS-Chem. *Environmental Research*, *195*, 110754. https://doi.org/10.1016/j.envres.2021.110754

[3] Thurston, G. D., Burnett, R. T., Turner, M. C., Shi, Y., Krewski, D., Lall, R., ... & Pope III, C. A. (2016). Ischemic heart disease mortality and long-term exposure to source-related components of US fine particle air pollution. *Environmental health perspectives*, *124*(6), 785-794. http://dx.doi.org/10.1289/ehp.1509777

secondary air pollutants, i.e., constituents that react chemically in the atmosphere and form harmful air pollutants downwind from the power plant. Primary air pollutants addressed here include $PM_{2.5}$ and $PM_{2.5}$ precursors include nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOCs), which can chemically react to form ozone and $PM_{2.5}$. Some of these air pollutants—including SO_2, NO_2, ozone, and $PM_{2.5}$—are Criteria Air Pollutants that are regulated by the U.S. Environmental Protection Agency (U.S. EPA) to protect human health and the environment.

Certain sensitive populations are particularly susceptible to the effects of air pollution. These groups include children, the elderly, people with underlying health conditions (such as asthma), and people with higher cumulative socioeconomic, health, and environmental burdens, among others (see Elena Krieger's testimony).

Air pollution can be transported over long distances before it is deposited on the Earth's surface either directly or through precipitation.[4] Thus, air pollution from power plants will impact both people who live near an emission source, such as a power plant, and people who live downwind from the source. This can include people living over a relatively large geographic area. Furthermore, because air pollution may travel far downwind, power plants can impact populated areas even if they are far away from the source.

Q: How do you evaluate the health impacts of power plants?

A: Air quality models are used to represent the transport and chemical fate of emissions in the atmosphere as well as the impacts of changes in emissions on human health. Our modeling efforts focused on $PM_{2.5}$ because there are numerous models that are widely used to

[4] National Research Council. (2010). *Global sources of local pollution: An assessment of long-range transport of key air pollutants to and from the United States*. National Academies Press. https://doi.org/10.17226/12743

represent atmospheric $PM_{2.5}$[5] and there is overwhelming epidemiological evidence that supports the relationship between $PM_{2.5}$ and human health.[6,7,8] The air quality models employed here use scientific methods to estimate the air quality and health impacts of emissions sources (such as a power plant). Air quality models take into account factors including the amount of emissions from a source, the physical characteristics of the emissions source, meteorology, atmospheric chemistry, and the epidemiological relationship between $PM_{2.5}$ and human health.

Q: Can you describe the models you used?

A: Two models were used to evaluate the $PM_{2.5}$-related health impacts of the power plants in the Consumers IRP. The first model was the U.S. EPA's CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool, or COBRA.[9] This model was first released in 2001, has precedent for use in policy decisions, and has been implemented widely in the scientific literature.[10] COBRA uses emissions data for pollutants that include $PM_{2.5}$, NO_x, SO_2, and VOCs and physical information about a source (e.g., stack height, fuel type) as inputs. Then, COBRA conducts a series of scientific calculations to translate the information about the source and emissions to a marginal change in annual-averaged

[5] Tessum, C. W., Hill, J. D., & Marshall, J. D. (2017). InMAP: A model for air pollution interventions. *PloS one*, 12(4), e0176131. https://doi.org/10.1371/journal.pone.0176131

[6] Dockery, D. W., Pope, C. A., Xu, X., Spengler, J. D., Ware, J. H., Fay, M. E., ... & Speizer, F. E. (1993). An association between air pollution and mortality in six US cities. *New England Journal of Medicine*, *329*(24), 1753-1759.

[7] Krewski, D., Jerrett, M., Burnett, R. T., Ma, R., Hughes, E., Shi, Y., ... & Tempalski, B. (2009). Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. *Res Rep Health Eff Inst*(140), 5-114; discussion 115-136.

[8] Lepeule, J., Laden, F., Dockery, D., & Schwartz, J. (2012). Chronic exposure to fine particles and mortality: an extended follow-up of the Harvard Six Cities study from 1974 to 2009. *Environmental Health Perspectives*, *120*(7), 965-970.

[9] COBRA information page: https://www.epa.gov/cobra

[10] List of publications that cite COBRA: https://www.epa.gov/system/files/documents/2021-10/cobra-publications_9.14.21.pdf

atmospheric $PM_{2.5}$ (from both primary pollutants and secondary precursors). Finally, COBRA uses concentration-response relationships from the peer-reviewed epidemiological literature to translate changes in $PM_{2.5}$ to health and monetary impacts. Metrics from COBRA are given on a county basis and are presented both as the number and monetary value of each health outcome.

Q: What about the second model?

A: The second model was the Intervention Model for Air Pollution or InMAP. This model is an independent air quality model that has been published in the peer-reviewed scientific literature.[11] InMAP uses pre-processed chemical and meteorological information from a state-of-the-science atmospheric model to estimate the marginal impacts of an emissions source on annual-averaged atmospheric $PM_{2.5}$. Like COBRA, InMAP takes primary emissions, secondary precursor emissions, and physical information about the emissions source as inputs. However, compared to COBRA, InMAP provides increased spatial granularity (up to 1 kilometer resolution) and integrates demographic data, providing the opportunity to quantify the spatial and environmental justice impacts of emissions shifts.

Q: Are there any health impacts that these models do not account for?

A: Both COBRA and InMAP only capture the health impacts from atmospheric (or outdoor) $PM_{2.5}$ that is emitted directly or is formed as a secondary pollutant from other pollutants emitted directly from the power plant itself. However, there are many other aspects of these power plants that impact human health, meaning our models underestimate the health impacts of the power plants evaluated here. For example, these models do not capture the

[11] Tessum, C. W., Hill, J. D., & Marshall, J. D. (2017). InMAP: A model for air pollution interventions. *PloS One*, 12(4), e0176131. https://doi.org/10.1371/journal.pone.0176131

direct impacts of volatile organic compounds (VOCs), many of which are carcinogenic.[12] There is evidence that sources across the entire oil and gas supply chain emit health-damaging VOCs, including during extraction and transmission, but lifecycle emissions are not incorporated into our models.[13] These models also do not capture the impacts of ozone, which forms through atmospheric reactions with precursors such as VOCs and NO_x and is the second most harmful outdoor air pollutant after $PM_{2.5}$ in terms of total impact.[14,15] Further, our models also do not capture the health impacts of other factors such as the on-site disposal of toxic materials or additional hazardous air pollutants near plants (see Elena Krieger's testimony).

Q: Are the models still valuable if they don't capture all of the health impacts?

A: While our models do not capture all health impacts, there is still sufficient evidence to make conclusions about which plants impact outdoor air quality the most and how the impacts of the plants are distributed spatially. Further, these models are frequently used in modeling, analysis, and decision making.

[12] U.S. Enivronmental Protection Agency's National Air Toxics Assessment (NATA): https://www.epa.gov/national-air-toxics-assessment

[13] Drew R. Michanowicz DR, Eric D. Lebel ED, Domen JK, Hill LAL, Jaeger, JM, Schiff JE, Krieger EM, Banan Z, Goldman JSW, Nordgaard CL, Shonkoff SBC. 2021. Methane and Health-Damaging Air Pollutants From the Oil and Gas Sector: Bridging 10 Years of Scientific Understanding. PSE Healthy Energy. Available at: https://www.psehealthyenergy.org/our-work/publications/archive/methane-and-health-damaging-air-pollutants-from-the-oil-and-gas-sector-bridging-10-years-of-scientific-understanding/.

[14] Lelieveld, J., Evans, J. S., Fnais, M., Giannadaki, D., & Pozzer, A. (2015). The contribution of outdoor air pollution sources to premature mortality on a global scale. *Nature*, 525(7569), 367-371. https://doi.org/10.1038/nature15371

[15] Murray, C. J., Aravkin, A. Y., Zheng, P., Abbafati, C., Abbas, K. M., Abbasi-Kangevari, M., ... & Borzouei, S. (2020). Global burden of 87 risk factors in 204 countries and territories, 1990–2019: a systematic analysis for the Global Burden of Disease Study 2019. *The Lancet*, *396*(10258), 1223-1249. https://doi.org/10.1016/S0140-6736(20)30752-2

IV. Power Plant Emissions

Q: What is the magnitude of total pollutants emitted from coal plants in the Consumers IRP, and which plants have the highest emission rates?

A: The *total* emissions (tons) and emissions *rates* (tons per MWh or tons per MMBtu) for nine of the plants outlined in the Consumers IRP are given in Tables 1 and 2, respectively. Data were collated data from a variety of sources to compile these estimates. NO_x, SO_2, CO_2, gross load, and steam load data are primarily from the U.S. EPA's Air Markets Program Database (AMPD).[16] CO_2 data for Midland and Dearborn are from the U.S. Energy Information Administration (EIA).[17] $PM_{2.5}$ emissions factors for the plants are from the Michigan Department of Environment, Great Lakes, and Energy (EGLE)[18] or the U.S. EPA's Emissions and Generation Resource Integrated Database (eGRID).[19] Total emissions were calculated using the emissions factors and gross and steam load data. Similarly, VOC data were derived using gross and steam load data and emissions factors from the scientific literature[20] or the U.S. EPA's Compilation of Air Pollutant Emissions Factors.[21] Emission rates were calculated by dividing the total emissions by the gross load of the plant or the heat input (for both the electricity and steam producing units) in the case of steam producing plants.

[16] U.S. EPA's Air Markets Program Database Tool (AMPD): https://ampd.epa.gov/ampd/
[17] U.S. Energy Information Administration (EIA): https://www.eia.gov/electricity/data.php
[18] Michigan Department of Environment, Great Lakes, and Energy (EGLE): https://www.michigan.gov/egle/
[19] U.S. EPA's Emissions and Generation Resource Integrated Database (eGRID): https://www.epa.gov/egrid
[20] Peng, Y., Yang, Q., Wang, L., Wang, S., Li, J., Zhang, X., ... & Fantozzi, F. (2021). VOC emissions of coal-fired power plants in China based on life cycle assessment method. *Fuel*, *292*, 120325.
[21] U.S. EPA's Compilation of Air Pollutant Emissions Factors: https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors

Table 1: Total emissions per year of fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs), and carbon dioxide (CO_2). Energy production per year in gross load and steam load. Emissions are from 2019 and are summed across units. Data are given in gigawatt-hours, 1,000 lbs, and metric tons.

Power Plant	Gross Load (GWh)	Steam Load (1,000 lbs)	$PM_{2.5}$ (tons)	VOCs (tons)	NO_x (tons)	SO_2 (tons)	CO_2 (megatons)
Dan E Karn[C, G]	1,976	690,359	47	2.9	557	516	2.0
J H Campbell[C]	9,025		538	13	2,918	5,244	8.2
Jackson Generating Station[G]	2,237		0.8	10	504	4.7	0.9
Zeeland Generating Station[G]	4,162		2.6	20	197	8.8	1.7
Midland Cogeneration Venture[G]	7,316	93,545	3.3	33	3,524	21	4.0
Kalamazoo River Generating Station[G]	60		0.6	0.5	17	0.2	0.04
Livingston Generating Station[G]	13		1.2	0.1	22	0.1	0.01
New Covert Generating Project[G]	7,616		71	34	177	14	2.8
Dearborn Industrial Generation[G,O]	3,665	4,614,373	70	20	535	610	1.9

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Total emissions (Table 1) indicate which plants have the highest overall pollutant emissions, while the emissions *rates* (Table 2, below) reflect which plants have the highest emissions per unit of energy generated or heat input (for the steam producing plants). Plants that have lower total emissions may have higher emissions rates, indicating that taking that plant offline would displace a larger proportion of overall emissions per energy produced.

Table 2: Emissions rates of fine particulate matter ($PM_{2.5}$), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2). Data are from 2019 and are summed across units. Values are in metric tons per terawatt hour of gross load or metric tons per metric trillion British thermal units (tons/MTBtu), to account for both electricity and steam production in the emissions rates.

Power Plant	$PM_{2.5}$ (tons/TWh)	VOCs (tons/TWh)	NO_x (tons/TWh)	SO_2 (tons/TWh)	CO_2 (megatons/TWh)
J H Campbell[C]	60	1.5	323	581	0.9
Jackson Generating Station[G]	0.3	5	225	2.1	0.4
Zeeland Generating Station[G]	0.6	4.8	47	2.1	0.4
Kalamazoo River Generating Station[G]	9.2	8.3	278	3.4	0.7
Livingston Generating Station[G]	93	8.5	1,724	4.3	0.8
New Covert Generating Project[G]	9.3	4.5	23	1.8	0.4
Power Plant	**$PM_{2.5}$ (tons/MTBtu)**	**VOCs (tons/MTBtu)**	**NO_x (tons/MTBtu)**	**SO_2 (tons/MTBtu)**	**CO_2 (megatons/MTBtu)**
Dan E Karn[C, G]	2.2	0.1	26	24	0.1
Midland Cogeneration Venture[G]	0.04	0.4	44.8	0.3	0.1
Dearborn Industrial Generation[G,O]	1.5	0.4	12	14	0.04

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Q: What are your findings with respect to emissions?

A: All nine power plants, including coal and gas plants, have health-damaging emissions (Table 1). The JH Campbell coal plant has the highest *total* emissions of $PM_{2.5}$ and SO_2. Retiring this plant would eliminate 538 tons of $PM_{2.5}$, 13 tons of VOCs, 2,918 tons of NO_x, 5,244 tons of SO_2, and 8.2 megatons of CO_2 per year. The Karn coal plant also had higher *total* $PM_{2.5}$ and SO_2 emissions than the natural gas plants that Consumers already owns or

purchases power from (i.e., Jackson, Zeeland, Midland). This finding supports the plan outlined in the Consumer's IRP to retire the Karn and Campbell coal plants earlier than their rated lifetime.

Several gas plants also have high emissions. For example, Midland has the highest NO_x emissions overall—a pollutant that has both primary health impacts and contributes to the formation of ozone and $PM_{2.5}$. Covert and Dearborn have the highest emissions out of the four plants that Consumers has proposed purchasing. In fact, the Dearborn gas plant has higher annual emissions than the Karn coal plant for all pollutant types analyzed except NO_x and CO_2. Depending on how Dearborn is operated, this plant may offset much of the emissions benefits from retiring Karn early.

Q: What does Table 2 show?

A: The emissions *rates* for the nine plants are in Table 2. Comparing the emissions rates on a per MWh basis, the Livingston gas plant has the highest emissions rate for all pollutants except for SO_2, which is higher from JH Campbell. This indicates that for every MWh of energy generated by Livingston there will be higher emissions of these pollutants than from any of the other plants, including the coal plants. Furthermore, the Karn and JH Campbell coal plants had some of the highest emissions rates of $PM_{2.5}$ and SO_2, although the gas plants generally had higher emissions rates for NO_x and VOCs. The emissions rate metrics highlight that, from an emissions perspective, the procurement of gas plants outlined in the Consumers IRP will not necessarily offset coal co-pollutant emissions per MWh of energy produced. This could be problematic, depending on how the energy load is balanced across the gas plants when the coal plants are retired. A better option would be to accelerate the transition to zero-emissions energy production (e.g., wind, solar, hydroelectric) coupled

with energy storage (see Elena Krieger's testimony) rather than purchasing new gas plants to ensure that emissions are not just shifted to a different plant.

Q: How can it be that a gas plant has as much emissions as a coal plant?

A: There are several ways a gas plant can have as much or more air pollutant emissions than a coal plant. For example, if a fuel other than natural gas is used at the facility this can increase *total* emissions or emissions *rates*. Dearborn uses waste gas from a steel plant in a blast furnace to produce steam in addition to pipeline natural gas. This blast furnace produces much higher emissions of $PM_{2.5}$ and SO_2 than the other pipeline natural gas units. Thus, using other fuels, in addition to natural gas, may increase emissions. Additionally, the chemical nature of the fuel and the conditions under which it is combusted (i.e., temperature, fuel-air ratio) can lead to changes in total emissions or emissions rates. For example, coal fuel itself contains sulfur, while natural gas only contains trace amounts of SO_2, unless sulfur-containing odorants are added. Meanwhile, there are several pathways that can lead to NO_x and VOCs being emitted when natural gas is combusted. [22] Depending on the combustion conditions and technology being used, VOCs or NO_x may be higher in natural gas combustion, relative to coal combustion. Finally, different plants may be outfitted with different emission control technologies at their stacks, leading to varying emission rates even for the same combustion technology and fuel type.

[22] Emissions from natural gas combustion: https://www.epa.gov/sites/default/files/2020-09/documents/1.4_natural_gas_combustion.pdf

V. Total Power Plant Health Impacts

Q: What are the overall public health impacts of these power plant emissions?

A: A summary of the annual $PM_{2.5}$-related health impacts from the nine plants in the Consumers IRP are given in Table 3. The full metrics given by COBRA are in Exhibit CEO-6 (KB-2) for Karn, JH Campbell, and Dearborn. Metrics are given for the total health impacts per plant and the health impacts per unit of energy generated or heat input (for the steam producing plants). These data are from the COBRA model, which uses a Source-Receptor Matrix to calculate the impacts of changes in emissions on $PM_{2.5}$ levels across the U.S.[23] COBRA then translates changes in $PM_{2.5}$ to health impacts using peer-reviewed epidemiological studies and population-level health metrics. The ranges given are the "low" and "high" estimates from COBRA, which capture the uncertainty associated with the relationship between $PM_{2.5}$ and health impacts. The two values are derived from two different epidemiological studies.

Table 3: National public health benefits of retiring power plants in 2019. Results are from COBRA using a 3% discount rate for the monetized health impacts.

[23] COBRA user manual: https://www.epa.gov/cobra/users-manual-co-benefits-risk-assessment-cobra-screening-model

Power Plant	Mortalities (cases, annual)	Mortalities (cases per TWh, annual)	Monetary Value of Total Health Impacts ($, annual)
J H Campbell[C]	36-81	4.0-9.0	$389-$879 million
Jackson Generating Station[G]	0.6-1.3	0.3-0.6	$6-14 million
Zeeland Generating Station[G]	0.2-0.5	0.05-0.12	$2-$5 million
Kalamazoo River Generating Station[G]	0.03-0.06	0.4-0.9	$0.27-$0.62 million
Livingston Generating Station[G]	0.02-0.05	1.6-3.5	$0.22-$0.50 million
New Covert Generating Project[G]	1.0-2.2	0.1-0.3	$11-$24 million

Power Plant	Mortalities (cases, annual)	Mortalities (cases per MTBtu, annual)	Monetary Value* ($, annual)
Dan E Karn[C, G]	3.8-8.6	0.2-0.4	$40-$92 million
Midland Cogeneration Venture[G]	2.5-5.7	0.03-0.07	$27-$62 million
Dearborn Industrial Generation[G,O]	7.5-17	0.2-0.4	$82-$184 million

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Q: Can you summarize your findings, as represented in the tables?

A: All nine plants evaluated here lead to premature mortalities, respiratory and cardiovascular impacts, and a substantial financial burden associated with these impacts (Table 3 and Exhibit CEO-6 (KB-2)). Further, all the plants have non-fatal respiratory and cardiovascular health impacts, affecting people's lives and livelihood both near and downwind from the plant. Greatly reducing, if not eliminating these impacts by converting to zero-emissions energy sources (e.g., wind, solar, hydroelectric) as soon as possible should be prioritized.

Q: Can you summarize the impact of Consumers retiring their coal plants?

A: Retiring the Karn and JH Campbell coal plants, as described in the Consumers IRP, will save approximately 40 to 90 lives per year and save $430-$972 million per year. JH Campbell is particularly important to retire as soon as possible because it has the highest total health impacts and the highest impacts on a per-MWh basis. Thus, converting the energy production of JH Campbell to zero-emission energy sources will lead to the most health benefit per MWh converted.

Q: Can you summarize the impact of the purchase of the gas plants?

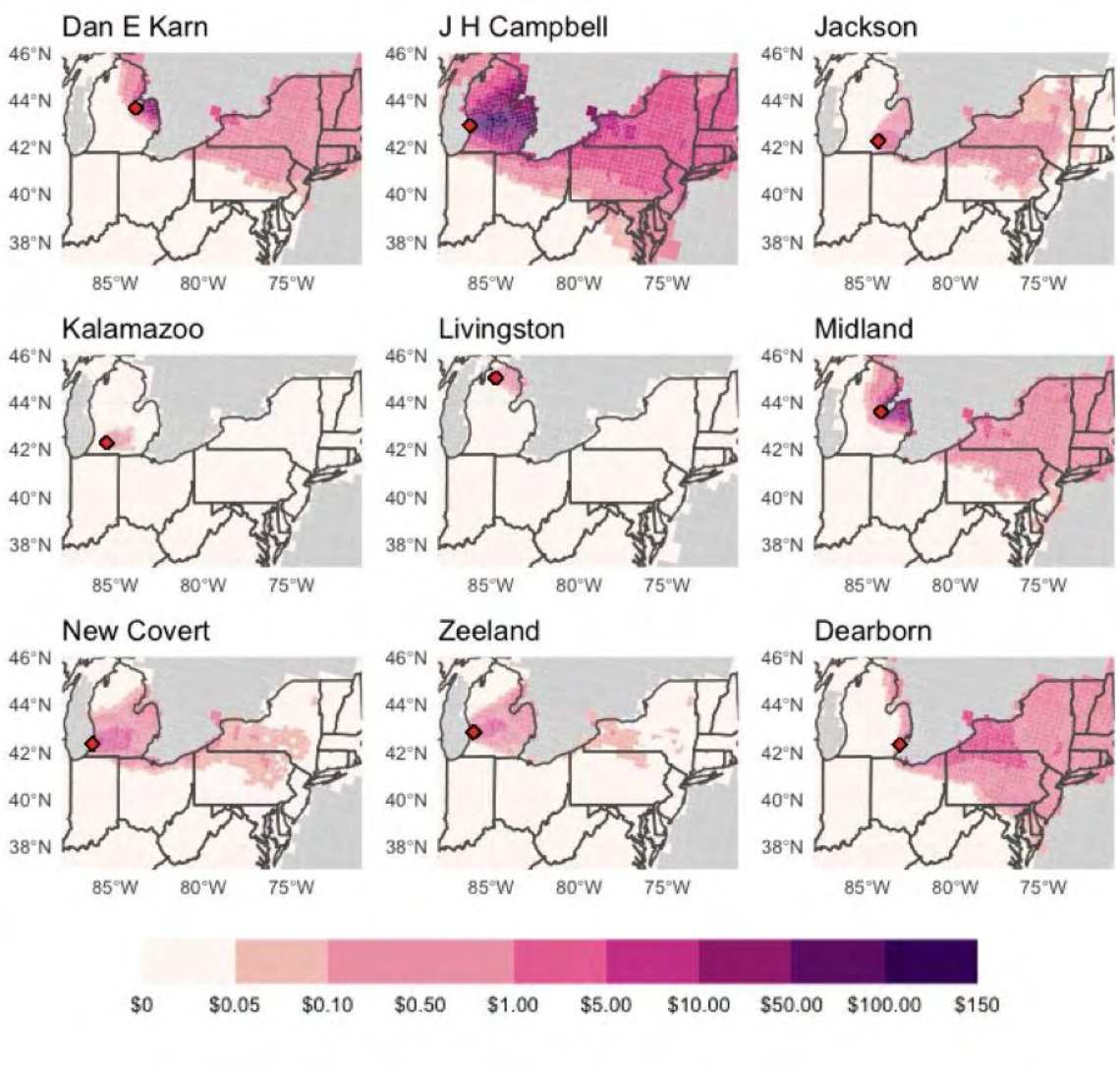
A: Operating Dearborn, Covert, Kalamazoo, and Livingston, the gas plants Consumers plans to purchase, at current levels, contributes to 9-19 premature mortalities per year and costs $93-209 million per year. Dearborn has the highest total health impacts of these four plants (7.5-17 mortalities per year) and cases per-MMBtu that are similar to the Karn coal plant. This is due in part to the disproportionately high levels of primary and secondary precursor pollutants—such as SO_2—being emitted from Dearborn and its proximity to high-density populations. Purchasing Dearborn to offset coal power in the near term could potentially counteract some of the benefits of retiring the Karn and JH Campbell plants early. Even though some of the fuel consumed at Dearborn is used to co-produce steam, rather than just electricity, purchasing the electricity produced at this plant will support its ongoing operation—and ongoing health impacts. Livingston has particularly high impacts per-MWh of energy produced (1.6-3.5 mortalities per-MWh per year), and any increase in operation at this plant would therefore have a higher impact on public health than a commensurate increase in generation at many other plants.

VI. Spatial Health Impacts

Q: Who is most affected by the emissions from these power plants?

A: Maps showing the spatial distribution of the public health impacts of nine of the power plants outlined are given below (Figures 1 and 2). Like COBRA, InMAP estimates the changes in primary and secondary $PM_{2.5}$ on an annual basis and uses a concentration-response function derived from epidemiological data to relate marginal changes in $PM_{2.5}$ to health impacts. Compared to COBRA, the InMAP modeling was conducted at a higher spatial resolution and incorporated demographic information; however, the InMAP modeling only included mortality as a health outcome.

Figure 1: Per capita public health impacts of each of the nine power plants. Values are given in $ per 100 people. The location of each plant is shown as a red dot. Health impacts were only evaluated in the contiguous U.S. Grid cells. Cells outside of the U.S. are shaded in gray. (Note: Data are from InMAP model runs. The analysis only included mortality as a health outcome and did not include a discount rate in the economic valuation.)



Q: What does Figure 1 show?

A: Figure 1 illustrates the fate of $PM_{2.5}$ in the atmosphere, both from primary $PM_{2.5}$ emissions and secondary precursors that react chemically in the atmosphere to form $PM_{2.5}$. The data

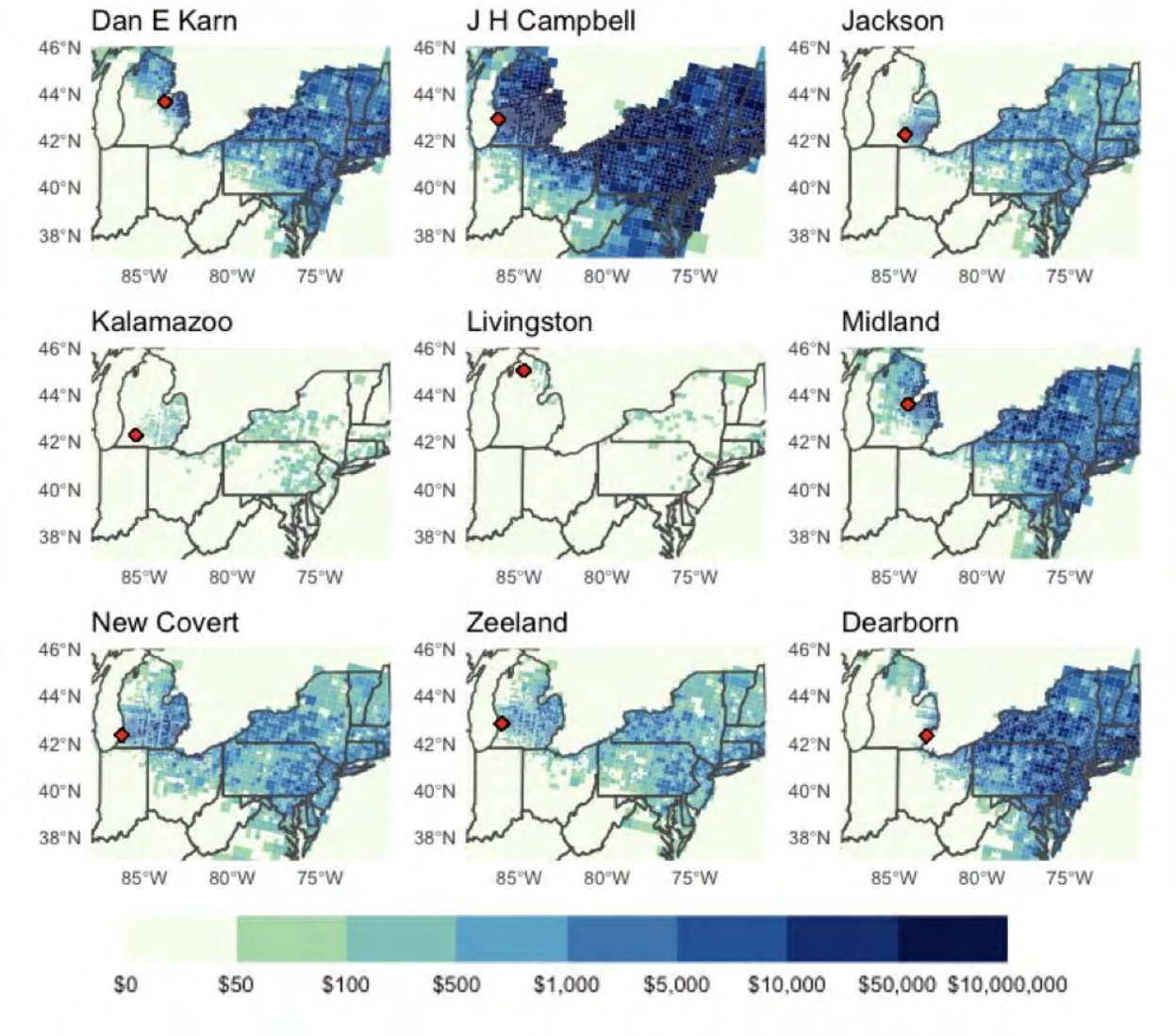
are normalized by population (e.g., $ per 100 people), so the health impacts scale with changes in atmospheric $PM_{2.5}$. The largest per-capita health impacts are near and directly downwind of the plants, because that is where the emissions from each plant impact air quality the most. However, $PM_{2.5}$ may stay suspended in the atmosphere for an extended period, travelling long distances downwind in the process. This is demonstrated by health effects experienced in outside of Michigan (e.g., New York and Pennsylvania). Although the impacts of the power plants on atmospheric $PM_{2.5}$ are lower downwind, there is still enough change in power-plant derived $PM_{2.5}$ to see health impacts.

Q: Where are the largest total impacts of the emissions from the power plants?

A: The largest *total* impacts from the power plants tended to be in the most densely populated areas that are typically downwind from each plant (Figure 2). Because these areas have larger populations, there is a higher statistical probability that someone will be impacted by $PM_{2.5}$ from a particular power plant. Even though states like New York are farther away from the Michigan-based power plants, they are heavily populated. Therefore, even small changes in $PM_{2.5}$ can have meaningful health impacts in this region.

The Karn and JH Campbell coal plants have far-reaching impacts, including substantial impacts outside of Michigan (e.g., in New York and Pennsylvania). Therefore, retiring these plants early, as proposed in the Consumers IRP, would have substantial public health benefits. The Midland gas plant, which Consumers purchases power from, also has substantial *total* health impacts, in part due to its proximity to populous areas. Following the Consumers IRP and retiring this plant early would have substantial public health benefits.

Figure 2: Cumulative public health impacts of each of the nine power plants in the Consumers IRP. Values are given in $. The location of each plant is shown as a red dot. Health impacts were only evaluated in the contiguous U.S. Grid cells outside of the U.S. are shown as zero. (Note: Data are from InMAP model runs. The analysis only included mortality as a health outcome and did not include a discount rate in the economic valuation.)



Q: What do you recommend based on your analysis of total health impacts?

A: As described earlier, the Dearborn gas plant has high *total* health impacts, likely because of the plant's proximity to Detroit and because the plant contributes to $PM_{2.5}$ in populated states such as New York. As mentioned in response to the previous question, depending

on how Dearborn is operated, acquiring Dearborn (as suggested by the Consumers IRP) could offset some of the benefits of retiring other plants early due to the higher emissions of Dearborn compared to the other plants. Thus, in addition to retiring the JH Campbell and Karn coal plants early, I recommend that Consumers does not purchase the Dearborn gas plant to offset energy production. Instead, better options from a public health perspective could include accelerating the zero-emissions energy sources or improving energy efficiency (see Elena Krieger's testimony).

Q: Do any of the power plants pose environmental justice concerns?

A: Per capita health impacts across race and ethnicity are given in Table 4. These data can be used to demonstrate the potential inequity of $PM_{2.5}$ exposures and related health impacts from the Michigan power plants. However, these metrics do not capture how these inequities will manifest themselves. For example, these data do not capture that people who have higher cumulative socioeconomic, health, and environmental burdens may be more sensitive to air pollution and poor air quality (see Elena Krieger's testimony).

Table 4: Per capita health impacts by race and ethnicity. Values given in $ per 100 people. (Note: Data are from InMAP model runs. The analysis only included mortality as a health outcome and did not include a discount rate in the economic valuation.)

Power Plant	Black	Latino	Native	Asian	White*	Overall
Dan E Karn[C,G]	2.5	2.0	1.8	2.9	4.8	3.9
J H Campbell[C]	153	58	67	97	180	150
Jackson Generating Station[G]	4.8	1.2	1.7	2.6	4.8	4
Zeeland Generating Station[G]	1.2	0.8	0.8	1.0	2.3	1.8
Midland Cogeneration Venture[G]	6.1	4.1	6.3	5.4	18	13
Kalamazoo River Generating Station[G]	0.1	0.05	0.07	0.08	0.2	0.2
Livingston Generating Station[G]	0.01	0.01	0.05	0.01	0.05	0.03
New Covert Generating Project[G]	3.4	1.4	1.8	1.9	4.2	3.5
Dearborn Industrial Generation[G,O]	57	18	9.4	14	18	23

* White, not including Latino
C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Q: Can you summarize your findings in Table 4?

A: All the plants in Table 4 except Dearborn have moderately higher per-capita health impacts for White people than the overall population. Additionally, the JH Campbell, Jackson, and Dearborn plants have higher health impacts per capita for Black people than the overall population. Dearborn has especially disproportionate impacts for Black people (2.5 times higher impacts per capita than the overall population), likely due to the plant's location at the edge of Detroit (see Elena Krieger's testimony).

Q: Are there any public concerns related to the use of fuels other than coal and natural gas?

A: The Dan E Karn Units 1 and 2 burn diesel oil and units 3 and 4 burn residual oil fuel as secondary fuels. These fuels, in addition to coal, have been linked to adverse health outcomes[24] and emit harmful pollutants beyond those discussed earlier, such as heavy metals.

Consumers also has several power purchase agreements for biomass power plants that primarily burn wood-derived and burn some tire-derived fuels. The total emissions (tons) and emissions rates (tons per MWh or tons per MMBtu) for the plants outlined in the Consumers IRP are given in Tables 1 and 2, respectively. Data were collated from a variety of sources following the methods described earlier. Emissions for NO_x and SO_x for Cadillac, Genesee, and Grayling were obtained from the EPA's AMPD. For most plants, $PM_{2.5}$, CO_2, and load data were obtained from the EPA's Power Plants and Neighboring Communities Tool; however, $PM_{2.5}$ data for Genesee were from EGLE, while gross load data for Grayling was from the U.S. EIA and steam load for Grayling was from the EPA's AMPD. All emissions for Viking Energy of Lincoln and Hillman Power Station were from the Power Plants and Neighboring Communities Tool.[25] The total emissions and emissions rates were derived in the same way as the fossil fuel plants, described above.

[24] Casey, J. A., Karasek, D., Ogburn, E. L., Goin, D. E., Dang, K., Braveman, P. A., & Morello-Frosch, R. (2018). Retirements of coal and oil power plants in California: association with reduced preterm birth among populations nearby. *American Journal of Epidemiology*, *187*(8), 1586-1594.

[25] U.S. EPA's Power Plants and Neighboring Communities Tool: https://www.epa.gov/airmarkets/power-plants-and-neighboring-communities

Table 5: Total emissions per year of fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Energy production in gross load and steam load per year. Emissions are from 2019 and are summed across units. Data are given gigawatt hours, 1,000 lbs, and metric tons.

Power Plant	Gross Load (GWh)	Steam Load (1,000 lb)	$PM_{2.5}$ (tons)	NO_x (tons)	SO_2 (tons)	CO_2 (megatons)
Cadillac Renewable Energy	96		3.1	119	39	0.19
Genesee Power Station	97		48	121	27	0.15
Grayling Generating Station	171	1,645,376	9.4	135	8.0	0.26
Viking Energy of Lincoln	144		20	191	18	0.18
Hillman Power Company	94		14	53	14	0.13

Table 6: Emissions rates of fine particulate matter ($PM_{2.5}$), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2). Values are in metric tons per terawatt hour of gross load or metric tons per metric trillion British thermal units (tons/MTBtu), to account for both electricity and steam production in the emissions rates.

Power Plant	$PM_{2.5}$ (tons/TWh)	NO_x (tons/TWh)	SO_2 (tons/TWh)	CO_2 (megatons/TWh)
Cadillac Renewable Energy	32	1,249	404	2.0
Genesee Power Station	496	1,242	282	1.6
Viking Energy of Lincoln	174	1,675	155	1.6
Hillman Power Company	150	565	152	1.3
Power Plant	**$PM_{2.5}$ (tons/MTBtu)**	**NO_x (tons/MTBtu)**	**SO_2 (tons/MTBtu)**	**CO_2 (megatons/MTBtu)**
Grayling Generating Station	3.7	53	3.2	0.1

Q: What conclusions do you reach from Tables 5 and 6?

A: The emissions *rates* of the biomass plants are comparable to the fossil-fuel power plants. For example, Genesee, Viking, and Hillman have higher $PM_{2.5}$ emissions than the JH Campbell coal plant per MWh generated. Although these fuels may be considered "renewable" they could have important health impacts. This could be because biomass tends to have lower heating values compared to other types of generation, which leads to less energy produced, as well as the fact the biomass is more likely to combust under poor fuel-oxygen conditions. Thus, transitioning to "renewable" fuel sources rather than zero-emissions energy production may still be problematic from a public health perspective.

VII. Benefits and Risks of the Consumers IRP

Q: From a public health standpoint, what are the public health risks and benefits of the proposed Consumers IRP?

A: I will summarize the risks and benefits of the Consumers IRP below:

Benefits:

- Rapidly retiring the Karn and JH Campbell coal plants as proposed will have substantial health benefits, saving approximately 40 to 91 lives and $430-$972 million for every year that the coal plants are retired early. JH Campbell especially should be prioritized, because it has the highest total health impacts of the coal and gas plant investigated here.
- The plan to transition fossil-fuel plants to zero-emissions energy sources (e.g., wind, solar) ahead of their rated lifetimes is a strong health benefit of the Consumers IRP.

Risks:

- All coal and natural gas plants have emissions resulting in $PM_{2.5}$-related health risks, hazards, and impacts. These impacts range from premature mortality to shorter term

impacts on the respiratory and cardiovascular health of people living near and downwind from the power plants. Only a swift and complete transitioning to zero-emissions energy (e.g., wind, solar, hydroelectric) coupled with energy storage, will eliminate potential air quality and public health impacts.

- Procuring new gas plants will increase the public health impacts of Consumers as compared to meeting this electricity demand with zero-emissions energy production. Purchasing Dearborn, Kalamazoo, Livingston, and Covert will increase the health burden of Consumers by 9-19 annual premature mortalities per year ($93-209 million per year).
- Procuring Dearborn, in particular, will have substantial health and equity impacts (7.5-17 annual premature mortalities). In fact, depending on how Dearborn is operated, this plant could potentially counteract some of the benefits of retiring the coal plants early. Furthermore, Dearborn poses substantial environmental justice and equity concerns. For example, Dearborn leads to *per capita* health impacts that are 2.5 times higher for Black people, compared to the overall population.
- Finally, the biomass plants that Consumers purchases power from have high emissions *rates*, which may lead to substantial health impacts.

Q: Is there anything else you would like to add to your testimony?

A: Recent epidemiological studies have identified health impacts at very low atmospheric concentrations of $PM_{2.5}$ as low as 2 $\mu g\ m^{-3}$.[26] The more quickly Consumers transitions to zero-emissions energy production coupled with battery storage, the more quickly the public health benefits described above can be realized. While the rapid retirement of the Karn and

[26] Christidis, T., Erickson, A. C., Pappin, A. J., Crouse, D. L., Pinault, L. L., Weichenthal, S. A., ... & Brauer, M. (2019). Low concentrations of fine particle air pollution and mortality in the Canadian Community Health Survey cohort. *Environmental Health*, *18*(1), 1-16.

JH Campbell coal plants aims to achieve this goal, the continued use of natural gas and the procurement of any new natural gas plants will continue to impact public health. Finally, biomass plants tend to have high emissions *rates*. Thus, while biomass plants may have climate benefits, if they have neutral or negative CO_2 emissions over the entire lifecycle, they are likely to have substantial health impacts due to their high emissions *rates*.

Q: Does this complete your testimony?

A: Yes.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 24

Mic. Pub. Power Agency Petition to Intervene

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of its Integrated Resource Plan pursuant to MCL 460.60t and for other relief.	))))))	Case No. U-21090

MICHIGAN PUBLIC POWER AGENCY'S PETITION TO INTERVENE

Michigan Public Power Agency ("MPPA"), by its counsel Dickinson Wright PLLC, respectfully submits this Petition to Intervene ("Petition") in Consumers Energy Company's ("Consumers") Integrated Resource Plan ("IRP") filing in Case No. U-21090 pursuant to Rule 410(1) and (2) of the Practice and Procedure Before the Commission, R.792.10410. In support of this Petition, MPPA states as follows:

1. MPPA is a public body politic and corporate of the State of Michigan created under 1976 PA 448, as amended, that exists to help its municipally owned members realize the benefits of joint action in the planning, development, acquisition and management of energy-related assets and services. Among other things, MPPA supplies wholesale electric power to many of its members, presently consisting of 22 Michigan community-owned electric utility systems that supply electric power at retail.

2. The Commission traditionally recognizes two bases for intervention by parties in contested case proceedings. The first type of intervention is where the party has standing to intervene as of right, which requires that the party: (i) will have suffered an injury in fact as a result of the outcome of the case; and (ii) be within the "zone of interest" to be protected by

statute. See, *Association of Data Processing Service Organizations, Inc v Camp*, 397 US 150 (1970); *Drake v Detroit Edison*, 453 F Supp 1123, 1127 (WD Mich 1978).

3. Consumers' Application indicates that through this proceeding, Consumers is specifically seeking approval of a Proposed Course of Action that includes the accelerated retirement of the J.H. Campbell Generating Plant No. 3, a 770 MW coal-fired generating plant ("Campbell Unit #3"), from December 31, 2039, to May 31, 2025. Application at ¶ 5(i).

4. MPPA owns a 4.80% undivided interest in Campbell Unit #3, as well as the common and joint facilities, among other interests.

5. MPPA was not given advance notice and as a result was unable to effectively plan for the loss of critical electric capacity and energy in its supply portfolio resulting from the 15-year acceleration in the retirement of Campbell Unit #3.

6. As an owner of Campbell Unit #3, whose accelerated retirement date is a subject of these proceedings, MPPA has a direct and immediate interest in this proceeding that cannot be adequately represented by another party.

7. MPPA will suffer an injury in fact if the accelerated retirement of Campbell Unit #3 impacts its ability to comply with the capacity demonstration requirement in MCL 460.6w and/or poses financial risk to its Member Participants associated with the sudden need and cost of replacing the capacity and/or energy from this power supply resource. Accordingly, MPPA is within the "zone of interest" to be protected by these proceedings.

8. The second type of intervention is permissive. The Commission exercises discretion to permit a party to intervene in the case where that party can provide useful information to the Commission or unique perspective on the issues to be resolved in the case.

See, e.g., *In re DTE Electric Co*, MPSC Case No. U-17319, p 10 (March 6, 2014), quoting, MPSC Case No. U-11057, pp 2-3 (June 5, 1996); see also, R792.10410 and 10412.

9. As a partial owner in Campbell Unit #3, MPPA can provide the Commission with useful information and/or a unique perspective that no other party can provide.

10. In sum, MPPA's timely intervention is in the public's interest and should be granted.

WHEREFORE, MPPA requests that the Commission:

(a) Grant MPPA's Petition to Intervene and that MPPA be treated as a party to this proceeding;

(b) Grant MPPA any other and further relief that it determines to be just and appropriate.

Respectfully submitted,

DICKINSON WRIGHT PLLC
Attorneys for Michigan Public Power Agency

By: Nolan J. Moody Digitally signed by Nolan J. Moody Date: 2021.07.19 09:23:32 -04'00'

Peter H. Ellsworth (P23657)
Nolan J. Moody (P77959)
123 W. Allegan Street, Suite 900
Lansing, MI 48933

Dated: July 19, 2021

4841-5231-0769 v1 [31402-89]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 25

2026 Consumers Energy Capacity Demonstration

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*Washington Office:
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Secretary and Chief
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General Counsel

Emerson J. Hilton
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Don A. D'Amato
Gary A. Gensch, Jr.
Matthew D. Hall
Georgine R. Hyden
Katie M. Knue
Robert F. Marvin
Jason M. Milstone
Rhonda M. Morris
Deborah A. Moss*
Chantez L. Pattman
Michael C. Rampe
Scott J. Sinkwitts
Spencer A. Sattler
Theresa A.G. Staley
Maribeth Tabaka
Janae M. Thayer
Anne M. Uitvlugt
Aaron L. Vorce
Attorney

December 21, 2022

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

Re: MPSC Case No. U-21225 – In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan, to file their capacity demonstrations as Required by MCL 460.6w.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2026**. A confidential version of this filing is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Digitally signed by
Gary A. Gensch, Jr.
Date: 2022.12.21
16:18:52 -05'00'

Gary A. Gensch, Jr.

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion to open a docket for load serving entities in Michigan, to file their capacity demonstrations as Required by MCL 460.6w.	)))))	Case No. U-21225

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

AFFIDAVIT OF TIMOTHY J. SPARKS

Timothy J. Sparks, being duly sworn, states that the following information and attached exhibits are true and accurate to the best of my reasonable knowledge and belief, regarding Consumers Energy Company's ("Consumers Energy" or the "Company") satisfaction of its Michigan capacity demonstration requirements:

1. I am the Vice President of Electric Supply for Consumers Energy. My responsibilities include, in part, overall responsibility for the Company's long-term and short-term electric supply planning, investments, and strategy. I am a registered professional engineer with the State of Michigan and a senior member of the Institute of Electrical and Electronics Engineers.

2. Consumers Energy is a public utility engaged in the generation, purchase, distribution, and sale of electric energy to approximately 1.9 million retail electric customers in the lower peninsula of the state of Michigan. For 136 years, Consumers Energy has provided reliable, affordable electricity to advance its customers' quality of life. Consumers Energy remains committed to planning for and providing an adequate electric supply to meet the needs of Michigan homes and businesses, with reliable, flexible, and cost-effective energy. The

Company's impact extends beyond supplying a commodity — Consumers Energy is a vital part of Michigan's economic, social, and environmental fabric as reflected in our Triple Bottom Line commitment to people, planet, and prosperity.

3. The information provided in this Affidavit is based on my first-hand knowledge of the Company's long-term and short-term electric supply planning, investments, and strategy. Pursuant to Section 6w of 2016 PA 341, and as required by the Michigan Public Service Commission's ("MPSC" or the "Commission") June 23, 2022 Order in Case Nos. U-21099 and U-21225, this Affidavit is a demonstration to the Commission that the Company has sufficient electric capacity arrangements for Planning Year[1] ("PY") 2026/2027. The remainder of this Affidavit discusses the Planning Reserve Margin Requirement ("PRMR"), peak demand outlook, and the capacity resources planned to fulfill customer need.

4. Consumers Energy remains dedicated to meeting the needs of its full-service electric customers over the four-year planning period while maintaining adequate reserve margins, as detailed in this filing, with:

- Demand Response ("DR") consistent with the Company's 2021 Integrated Resource Plan ("IRP") Proposed Course of Action ("PCA") as approved in MPSC Case No. U-21090 ("IRP Settlement"). As DR programs evolve, there may be shifting of DR levels among the different programs;
- Offered capacity generated from existing resources in the applicable Michigan Zone;
- Contracted amounts of Power Purchase Agreements ("PPA") in accordance with the terms of the applicable agreements; and
- Renewable capacity from existing and new resources, as identified in this filing consistent with the Company's Renewable Energy Plan and IRP PCA.

[1] Planning Year, as defined by the Midcontinent Independent System Operator, Inc. ("MISO"), is the 12-month period commencing on June 1 of each year and concluding on May 31 of the following year

Specifically, some key aspects reflected in this filing include:

- Continued and expanded use of the Company's Energy Waste Reduction ("EWR") Programs and DR resources to help reduce customer demand;

- Continued use of existing resources including the J.H. Campbell Plant (through retirement in May 2025), D.E. Karn ("Karn") Units 1 and 2 (through retirement in May 2023), Karn Units 3 and 4 (through retirement in May 2031), the Ludington Pumped Storage Plant, the newly acquired Covert Generating Plant (target June 2023), Zeeland and Jackson Generating Plants, the Cross Winds, Lake Winds, Gratiot Farms Wind, and Crescent Wind Energy Parks, and the planned Heartland Wind Farm.

- Power supply contracts with Midland Cogeneration Venture Limited Partnership and other non-utility generators; and

- Renewable additions to meet the 2016 PA 342 Renewable Portfolio Standard of 15% and in support of the state's 35% goal for renewable energy and EWR, and as consistent with Case No. U-21090.

5. Consumers Energy plans to sufficiently serve its full-service customers with safe, affordable, reliable, and sustainable energy for the next four years and beyond. The Company's plans are outlined in the following paragraphs, covering PYs 2023 through 2026, and address each of the required capacity areas:

- Exhibit 1 — Utility Bundled Service Peak Demand for Michigan MISO LRZ 7;

- Exhibit 2 — Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC);

- Exhibit 3 — Demand Response—Capacity Resources;

- Exhibit 4 — Company-Owned Electric Generation Resources (Confidential);

- Exhibit 5 — New or Upgraded Generation Owned;

- Exhibit 6 — Generation Resources Under PPA or Other Capacity Contract (Confidential); and

- Exhibit 7 — New or Upgraded Purchased Power.

6. Midcontinent Independent System Operator, Inc. ("MISO") Module E Reports for Planning Year 2022/23:

Reports from the MISO Module E Capacity Tracking tool demonstrating the unforced[2] capacity ("UCAP") confirmed by the Company for Planning Year 2022/23 are provided as Exhibits 8 through 11.

- Exhibit 8 — Existing Owned Generation (Confidential);
- Exhibit 9 — Demand Response Programs—Not Netted Against Load (Confidential);
- Exhibit 10 — Existing Purchased Power Agreements (Confidential); and
- Exhibit 11 — Existing Transactions (Confidential).

7. Tariffs

Relevant tariffs are included in this filing as Exhibit 12. In lieu of filing a copy of the customer supply contracts with this capacity demonstration, the Company agrees to make available the customer supply contracts relevant to the Commercial and Industrial Demand Response ("C&I DR") Program and Interruptible Service ("Rate GI") Provision for the Commission Staff's ("Staff") review upon request, without Staff retaining a copy. Exhibit 13 contains the contact information of the persons designated to make available the customer supply contracts and copies of any of the Company's PPAs for review by Staff.

8. PRMR

The capacity planning reserve margin target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to ensure that sufficient capacity exists to provide adequate electric supply in each PY period. The Company relies on MISO to determine the appropriate capacity Planning Reserve Margin ("PRM") that Consumers Energy should maintain.

[2] MISO's evaluation of Loss of Load Expectation for PY 2022/23 utilized net demonstrated capacity less the three-year Equivalent Forced Outage Rate on demand, or "EFORd." The resulting capacity value is commonly referred to as "unforced."

For PY 2023, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. MISO's Planning Year 2023-2024 Loss of Load Expectation Study Report was published on November 1, 2022. Upon determining the amount of generation resources that would be necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

MISO's new seasonal construct, accepted by the Federal Energy Regulatory Commission in September 2022, introduces seasonal requirements to the Planning Resource Auction ("PRA"). As a result, MISO's LOLE study sets the system-wide capacity Planning Reservice Margin Unforced Capacity ("PRM UCAP") and the zonal Local Reliability Requirements ("LRR") for each season for the upcoming 2023/224 Planning Year. Under the MISO new seasonal construct, the annual planning year will be divided into 4 distinct seasons between June 1, 2023, and May 31, 2024, and for subsequent planning years moving forward. The seasons are summer from June 1 – August 31, fall from September 1 – November 30, winter from December 1 – February 28, and spring from March 1 and May 31.

On November 1, 2022, MISO determined seasonal PRM UCAP planning reserve margin targets for PY 2023/2024 of 7.4% for Summer, 14.9% for Fall, 25.5% for Winter, and 24.5% for Spring (as opposed to seasonal installed capacity ("ICAP") planning reserve margin targets for PY 2023/2024 of 15.9% for Summer, 25.8% for Fall, 41.2 % for Winter, and 39.3% for Spring.[3] While MISO provided PRM UCAP data for each season, the Commission issued an Order in

[3] As presented in MISO's report titled "Planning Year 2023-2024 Loss of Load Expectation Study Report", page 35.https://cdn.misoenergy.org/PY%202023%202024%20LOLE%20Study%20Report626798.pdf The Total PRMR for Consumers Energy is shown on Exhibit 2, line 8.

MPSC Case No. U-21225 stating that all Michigan LSEs shall file capacity demonstrations for PY 2026/2027 either by using the prompt year summer season capacity obligation and resource credit assumptions for the entire planning year or by providing a demonstration based on each individual season's capacity obligation and resource credits for the prompt year (see the November 18, 2022 order in MPSC Case No. U-21225, page 5). The Company is filing this capacity demonstration for PY 2026/2027 using the prompt year summer season capacity obligation and resource credit assumptions for the entire planning year. The Company also forecasted load requirements for the 2026/2027 PY as it has done for prior capacity demonstrations. The Company will plan to meet the Company's PRMR and thus maintain resources to meet full-service customer capacity needs throughout the PY, including during peak load periods.

9. Peak Demand

The Company's historical and forecasted peak demands are shown in Exhibit 1. The values provided in Exhibit 1 are not weather-normalized. The peak demands shown in Exhibit 1 include supplying demand associated with Bundled (full-service) customers, Choice customers through Retail Open Access, and the summation of Bundled and Choice customers denoted as Service Territory peak demand.

Existing DR or EWR resources netted against load are detailed in the section below and can be found in Exhibit 2, line 2.

The Company must plan for capacity during periods when MISO experiences its peak demand. The Company's forecast of peak bundled demand is adjusted to align with MISO's peak demand, which requires application of a -3.96% diversity factor as shown in Exhibit 2, lines 4 and 5. The Company's forecast of peak bundled demand is also adjusted to include transmission

losses, which requires application of a transmission loss factor of 4.50% as shown in Exhibit 2, line 6.

Consumers Energy plans to draw on a diverse portfolio of resources to meet its annual PRMR obligation. Those resources include utility-owned generation, long-term supply contracts, EWR, and DR resources.

10. Existing Generation — Owned

Consumers Energy currently owns, operates, and manages resources all located within Michigan and within MISO Zone 7 and plans to offer the load serving entity capacity from these resources in the applicable Michigan Zone throughout the four-year planning period. A summary of the Company's forecast for its owned resources — including resource type, installed capacity, and Installed Seasonal Accreditation Capacity ("ISAC") — is provided in Exhibit 2 (by category) and Exhibit 4 (by unit).

The total Seasonal Accreditation Capacity ("SAC") associated with the Company's owned resources is expected to stay relatively consistent (between approximately 4,500 and 5,600 Zonal Resource Credits ("ZRCs")) through PY 2026 due to the replacement of Karn Units 1-2 with Covert Generating Station, and steady growth in renewable capacity.

11. Existing DR or EWR Resources (Not Netted Against Load)

Consumers Energy offers a suite of Demand-Side Management programs available for residential, commercial, and industrial customer classes to deliver and manage significant peak load reductions. Existing programs offered by the Company that are not netted against load and can be offered into MISO as a capacity resource include:

- Air Conditioning Peak Cycling ("ACPC") Program;

- Energy Intensive Primary Rate ("Rate EIP");[4]
- Commercial & Industrial Demand Response;
- Rate GI/GI Long Term Industrial Load Retention Rate ("LTILRR");
- Smart Thermostat Program; and
- Business Smart Thermostat Program.

Existing Demand-Side Management programs not netted against load result in total load-modifying resources as shown in Exhibit 2, line 18. Exhibit 3 provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio. Exhibit 9 summarizes these DR programs with data from the MISO Module E Report for PY 2022/2023. Growth in these Demand-Side Management programs (in combination with those netted against load) is consistent with the IRP Settlement.

Transmission losses and the planning reserve margin (on a UCAP basis) were applied per MISO standard practice for registered DR capacity, as detailed in (BPM-011-r25).[5]

Existing DR resources will continue to be renewed with MISO through the Resource Adequacy process. Consumers Energy plans to maintain this level of resources throughout the four-year planning period, plus the growth noted further below.

12. Existing DR or EWR Resources (Netted Against Load)

Existing DR and EWR programs netted against load include Dynamic Peak Pricing, Residential Summer on-peak rate RSP, EWR, and Conservation Voltage Reduction (Exhibit 2, line 2, less new DR or EWR resources netted against load). Growth in these Demand-Side

[4] Rate EIP was offered as a capacity resource in the past but was then discontinued. The Company plans to include this program as a capacity resource starting with PY 2024.
[5] https://www.misoenergy.org/legal/business-practice-manuals/

Management programs (in combination with those not netted against load) is consistent with the IRP Settlement. The applicable tariff sheets are included in Exhibit

13. New or Upgraded Utility-Owned Generation

New or upgraded utility-owned generation planned for 2023 through 2026 includes new renewable resources in accordance with the Company's Renewable Energy Plan and the IRP Settlement. Details for these resources including planned in-service dates, expected regulatory approval dates, and expected dates for a MISO Generator Interconnection Agreement can be found in Exhibit 5. The addition of these resources in the Company's capacity planning projections are reflected in the annual values shown in Exhibit 2 (in combination with existing units) and Exhibit 4 (by individual unit) and are based on the construction and Commercial Operation Dates identified in Exhibit 5.

14. New DR or EWR Resources (Not Netted Against Load)

Starting in PY 2023, the Company plans to add a new DR program called Business DPP that is not netted against load and can be offered into MISO as a capacity resource. Exhibit 3 provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio for Business DPP and other existing Company DR or EWR programs.

15. New DR or EWR Resources (Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would be netted against load.

16. Existing Generation Capacity Contracts

The Company has a number of PPAs in place for the purchase of energy, capacity, and renewable energy credits. The majority of Consumers Energy's PPAs are sourced within Michigan and within MISO Zone 7—the exception being the Heritage Garden Wind Farm, which

is located in MISO Zone 2. The Company has several contracts in place with facilities that have, or are expected to, meet the requirements of Qualifying Facilities ("QFs"), in accordance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"), that will terminate from 2023 to 2027. Exhibit 6 presents a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations. New PPAs where there were existing PURPA facilities are identified on page 2 of Exhibit 6.

17. New or Upgraded Purchased Power

The Company's New or Upgraded Purchased Power resources are presented in Exhibit 7. There are three types of resources detailed in this exhibit. First, the Company has forecasted that existing PURPA-based contracts will be replaced with new PURPA-based agreements.[6] Obligations for these contracts are projected to remain throughout the four-year planning period. The ZRCs associated with new PURPA-based contracts are identified in Exhibit 6, line 48. Second, the Company has contracted PPAs for new solar PURPA capacity per the Settlement Agreement in Case No. U-20615 ("PURPA Settlement"). Exhibits 6 and 7 present a forecast of the PURPA Settlement solar projects expected to achieve commercial operation through PY 2026. Because interconnection agreements and full construction schedules for many of these resources are not yet finalized, the expected construction dates presented in Exhibit 7 are subject to change. Third, Exhibit 6, line 1, and Exhibit 7, line 44, summarizes new solar capacity expected to be online starting in PY 2026, consistent with the IRP Settlement Finally, Exhibit 6, lines 2 through 4, and Exhibit 7, lines 1 through 3, show the details for 700 ZRCs from the One-Time Solicitation as agreed to in the IRP Settlement.

[6] Except the contract with Hillman Power Company, which includes a provision for the supplier to decommission the plant at the end of the current contract, as approved by the Commission in MPSC Case No. U-20496.

To reduce potential risks associated with mid-PY retirements of generation assets, the Company has assumed the ZRCs associated with existing generation capacity contracts terminating before the end of each PY are not included in that PY's contracted capacity.

Consumers Energy plans to maintain the contracted amounts of these PPAs as shown in the attached exhibits and in accordance with the terms of the applicable agreements throughout the four-year planning period.

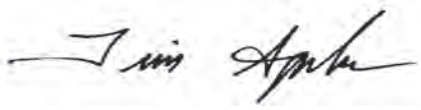
18. Forward ZRC Contracts

The Company has no forward ZRC contracts in PYs 2023 through 2026.

19. Planning Resource Auction Purchases

The Company does not project Planning Resource Auction purchases for PYs 2023 through 2026 as shown in Exhibit 2.

If sworn as a witness, I would testify as set forth above.



Timothy J. Sparks

Subscribed and sworn to before me this 21st day of December 2022.

Jennifer Joy Yocum, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 12/17/24
Acting in the County of Jackson

Case No:	U-21225
Utility:	Consumers Energy Company
Date:	December 21, 2022
Season	Summer
Exhibit:	1 of 13 - Peak Demand Bundled Service

Exhibit 1—Utility Bundled Service Peak Demand for Michigan MISO LRZ 7

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
		PY 2020-21	**PY 2021-22**	**PY 2022-23**	**PY 2023-24**	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**
		Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)							
1	Service Territory	8,215	7,951	8,061	8,171	8,228	8,253	8,349
2	Choice, Coincident to Service Territory	540	581	585	503	497	456	480
3	Bundled (line 1 - line 2)	7,675	7,370	7,476	7,667	7,730	7,797	7,869
	Coincident to MISO Sys.Peak Demand (MW)							
4	Service Territory	7,738	7,951	7,989	7,847	7,902	7,926	8,018
5	Choice, Coincident to Service Territory	535	581	542	483	478	438	461
6	Bundled (line 4 - line 5)	7,203	7,370	7,447	7,364	7,424	7,488	7,557

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

Case No:	U-21225
Utility:	Consumers Energy Company
Date:	December 21, 2022
Season	Summer
Exhibit:	2 of 13 - Planning Resources

Exhibit 2—Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC)

Line	(a)	(b) PY 2023-24	(c) PY 2024-25	(d) PY 2025-26	PY 2026-27
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,667	7,730	7,797	7,869
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	874	952	1,042	1,152
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	6,794	6,778	6,755	6,717
4	Load Diversity Factor coincident to MISO, %.	96.04%	96.04%	96.04%	96.04%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,525	6,510	6,488	6,451
6	Transmission Losses, %	4.50%	4.50%	4.50%	4.50%
7	Planning Reserve Margin % UCAP Basis	7.40%	7.40%	7.40%	7.40%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,323	7,306	7,282	7,240
9	Company Owned, In-State, Non-Intermittent, ZRC	5,387	5,376	4,191	4,194
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	18	18	18	18
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	79	186	265	525
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	15	15	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,498	5,594	4,489	4,751
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	558	606	692	702
19	PPA, In-State, Non-Intermittent, ZRC	1,595	1,588	1,999	1,999
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	32	32	27	23
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	121	221	558	683
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	3	3	18	18
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	0	0	3	9
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	109	222	328	328
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,861	2,067	2,933	3,060
32	Net Load Switching, ZRC	-	-	-	-
33	Planned Auction Purchases, ZRC	-	-	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	7,916	8,267	8,114	8,513
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	594	960	833	1,273

Case No.:	U-21225
Utility:	Consumers Energy Company
Date:	December 21, 2022
Season	Summer
Exhibit No.:	3 of 13 - DR Program Resources

Exhibit 3—Demand Response—Capacity Resources

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2023-SAC**	Air Conditioning Peak Cycling(ACPC)	44	5	49
2		Rate EIP	-	-	-
3		C&I DR 5	200	25	225
4		Rate GI/Rate GI LTILRR	199	24	223
5		Small Business DPP	18	2	20
6		Smart Thermostat Program (STP)	35	4	39
7		Business STP	1.0	0	1.1
8					-
9	**Total Demand Response - Capacity Resources PY 2023-2024 (ZRC)**				557.5
10	**PY 2024-SAC**	Air Conditioning Peak Cycling(ACPC)	45	6	51
11		Rate EIP	10	1	11
12		C&I DR 5	220	27	247
13		Rate GI / Rate GI LTILRR	199	24	223
14		Small Business DPP	15	2	17
15		Smart Thermostat Program (STP)	40	5	45
16		Business STP	11.0	1	12.3
17					-
18					-
19	**Total Demand Response - Capacity Resources PY 2024-2025 (ZRC)**				605.6
20	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	47	6	53
21		Rate EIP	10	1	11
22		C&I DR 5	290	36	326
23		Rate GI / Rate GI LTILRR	199	24	223
24		Small Business DPP	15	2	17
25		Smart Thermostat Program (STP)	43	5	48
26		Business STP	13.0	2	14.6
27					-
28					-
29	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				692.1
30	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	48	6	54
31		Rate EIP	10	1	11
32		C&I DR 5	295	36	331
33		Rate GI / Rate GI LTILRR	199	24	223
34		Small Business DPP	15	2	17
35		Smart Thermostat Program (STP)	46	6	52
36		Business STP	13.0	2	14.6
37					-
38					-
39	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				702.2

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21225
Utility: Consumers Energy Company
Date: 12/21/2022
Season: Summer
Exhibit: 5 of 13 - New Electric Generation List

Exhibit 5—New or Upgraded Generation Owned

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	Heartland Wind Farm	Wind	201	81.90%	36	12/31/2023	complete	complete	August 2022	July 2024	
2	Parkview Battery	Battery Storage	0.3	5.00%	0.3	6/1/2022	complete	N/A	May 2021	May 2022	
3	Circuit West Battery	Battery Storage	0.2	5.00%	0.2	6/1/2022	complete	N/A	May 2021	May 2022	
4	Muskegon Solar	Solar	250	50.00%	125	12/31/2025	complete	complete	August 2023	December 2025	
5	Covert	Natural Gas	1128	2.77%	1097	6/1/2023	complete	March 2023	n/a	n/a	[1]
6	Mustang Mile Solar Project	Solar	150	50.00%	75	5/31/2024	complete	complete	October 2022	May 2024 (Estimated)	[2]
7	Washtenaw Solar Project	Solar	150	50.00%	75	5/31/2024	complete	complete	Q2 2023	May 2024 (Estimated)	[3]
8	250 MW 2025 Solar - Owned	Solar	250	50.00%	125	1/1/2026	December 2023	March 2024	August 2024	December 2025	
9	2024 Settlement E+C Storage	Battery Storage	3	5.00%	3	12/1/2024	N/A	N/A	Q4 2023	Q4 2024	[4]
10	2024 Settlement DAD Storage	Battery Storage	2	13.30%	2	12/1/2024	N/A	N/A	Q4 2023	Q4 2024	[4]
11	2025 Settlement E+C Storage	Battery Storage	8	5.00%	8	12/1/2025	N/A	N/A	Q4 2024	Q4 2025	[4]
12	2025 Settlement DAD Storage	Battery Storage	2	13.30%	2	12/1/2025	N/A	N/A	Q4 2024	Q4 2025	[4]

Source:
MISO LOLE report: 2023-2024 Pooled EFORd Class Averages

Notes:
[1] Covert capacity credit % is not class average, as the unit has only changed ownership and has historical data for a calculated accreditation
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP byQ2 2023
[4] Battery solicitation entries have estimated construction dates

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21225
Utility: Consumers Energy Company
Date: 12/21/2022
Season: Summer
Exhibit: 7 of 13 - New PPA Resource List

Exhibit 7—New or Upgraded Purchased Power

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date	
1	500 ZRC dispatchable solicitation	Natural Gas	528	94.46%	499	June 2025	Q2 2023	N/A	N/A	N/A	N/A	[1]
2	IRP settlement 200 ZRC intermittent solicitation - 50% solar portion	Solar	200	50.00%	100	June 2025	Q2 2023	Q1 2023	Q1 2024	March 2024	May 2025	[2]
3	IRP settlement 200 ZRC intermittent solicitation - 50% storage portion	battery storage	105	95.00%	100	June 2025	Q2 2023	Q1 2023	Q1 2024	March 2024	May 2025	[2]
4	Addle	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	September 2023	November 2024	
5	Allegheny Solar	Solar	11	50.00%	5	December 2024	Complete	n/a	n/a	September 2023	November 2024	
6	Aluminum Solar	Solar	8	50.00%	4	December 2024	Complete	n/a	n/a	March 2024	November 2024	
7	Aurthur Solar Farm, LLC	Solar	2	50.00%	1	December 2023	Complete	n/a	n/a	January 2023	November 2023	
8	Blue Elk Solar I	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	May 2023	November 2024	
9	Blue Elk Solar II	Solar	10	50.00%	5	December 2023	Complete	n/a	n/a	March 2023	November 2023	
10	Blue Elk Solar III	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023	
11	Blue Elk Solar IV	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023	
12	Blue Elk Solar VII	Solar	12	50.00%	6	December 2023	Complete	n/a	n/a	November 2022	November 2023	
13	Byrne Solar	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	March 2022	September 2023	
14	Calhoun Solar Energy	Solar	140	50.00%	70	May 2023	Complete	Complete	Complete	July 2021	May 2023	
15	Cement City	Solar	20	50.00%	10	December 2022	Complete	n/a	n/a	April 2021	December 2022	
16	Cereal City	Solar	100	50.00%	50	December 2023	Complete	Complete	Q3 2023	July 2023	December 2023	
17	Copenhagen	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	September 2023	November 2024	
18	Golden Solar Farm, LLC	Solar	2	50.00%	1	December 2023	Complete	n/a	n/a	January 2023	November 2023	
19	Greenstone Solar, LLC	Solar	0.2	50.00%	0.1	August 2023	Complete	n/a	n/a	January 2022	July 2023	
20	Heartwood Solar	Solar	150	50.00%	75	December 2024	Complete	Q1 2023	April 2023	June 2023	December 2024	
21	Heathlands Solar	Solar	30	50.00%	15	December 2024	Complete	n/a	n/a	October 2022	December 2024	
22	Heritage Garden Solar II	Solar	1	50.00%	1	June 2022	Complete	n/a	n/a	January 2021	June 2022	
23	Hogan Solar	Solar	12	50.00%	6	December 2024	Complete	n/a	n/a	September 2023	November 2024	
24	Holly	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	September 2023	November 2024	
25	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Q3 2023	September 2023	May 2025	
26	Johnsfield Solar	Solar	10	50.00%	5	June 2024	Complete	n/a	n/a	January 2021	May 2024	
27	Lake City Solar	Solar	2	50.00%	1	December 2023	Complete	n/a	n/a	January 2023	November 2023	
28	Letts Creek	Solar	15	50.00%	8	December 2022	Complete	n/a	n/a	April 2021	November 2022	
29	Lightfoot Solar	Solar	10	50.00%	5	August 2023	Complete	n/a	n/a	September 2022	July 2023	
30	Midcontinent Solar, LLC	Solar	20	50.00%	10	September 2023	Complete	n/a	n/a	November 2022	August 2023	
31	Olivier	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	September 2023	November 2024	
32	Puck	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	September 2023	November 2024	
33	Pullman	Solar	20	50.00%	10	December 2022	Complete	n/a	n/a	April 2021	November 2022	
34	River Fork Solar	Solar	100	50.00%	50	March 2024	Complete	Complete	Complete	November 2021	March 2024	
35	Robert Swift Solar Farm, LLC	Solar	2	50.00%	1	December 2023	Complete	n/a	n/a	January 2023	November 2023	
36	Shipsterns Solar	Solar	20	50.00%	10	September 2023	Complete	n/a	n/a	September 2022	August 2023	
37	Shoreline (new Pine Gate)	Solar	20	50.00%	10	December 2024	Complete	n/a	n/a	November 2023	November 2024	
38	Sunbelievable	Solar	12	50.00%	6	December 2024	Complete	n/a	n/a	May 2023	November 2024	
39	Surbrook Solar	Solar	10	50.00%	5	January 2024	Complete	n/a	n/a	July 2023	January 2024	
40	Surrey Road Solar	Solar	2	50.00%	1	December 2023	Complete	n/a	n/a	January 2023	November 2023	
41	Thorn Lake	Solar	20	50.00%	10	October 2024	Complete	n/a	n/a	March 2024	September 2024	
42	Topanga Solar	Solar	20	50.00%	10	January 2024	Complete	n/a	n/a	March 2023	January 2024	
43	Wilford Solar	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	September 2022	October 2023	
44	250 MW 2025 Solar - PPA	Solar	250	50.00%	125	January 2026	July 2023	Q1 2023	Q1 2024	June 2024	December 2025	[2]
45												

[1] 500 ZRC dispatchable solicitation is assumed to be an existing facility
[2] Unsolicited Expansion Plan Resources have estimated approval and construction dates based on the published MISO Interconnection Queue

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.058841*	$ *0.041238*	$*0.100079*	per kWh for Off-Peak kWh between June 1 and September 30
$ *0.087901*	$ *0.061354*	$*0.149255*	per kWh for On-Peak kWh between June 1 and September 30
$ *0.058608*	$ *0.040126*	$*0.098734*	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.059076*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-15.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise RIA and LIAC)

Second Revised Sheet No. D-15.00
Cancels First Revised Sheet No. D-15.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the *total* household *income does not exceed 150% of the Federal Poverty level*, a credit shall be applied during all billing months. *The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:*

1. *A Home Heating Credit energy draft*
2. *State Emergency Relief*
3. *Assistance from a Michigan Energy Assistance Program (MEAP)*
4. *Medicaid*

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision *(RIA)* shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need *and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:*

1. Customers *whose* total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who *have received assistance from a Michigan Energy Assistance Program (MEAP)*
3. Customers who have received a Home Heating Credit *energy draft*
4. *A* State Emergency Relief *program*
5. Medicaid
6. *Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.*

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

(Continued on Sheet No. D-16.00)

Issued June 15, 2021 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after June 10, 2021

Issued under authority of the Michigan Public Service Commission dated June 9, 2021 in Case No. U-21043

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To rename Device Cycling Program)

Second Revised Sheet No. D-16.00
Cancels First Revised Sheet No. D-16.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Peak Power Savers:

Customers can elect to participate in the *Device* Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the *total credit earned under the Device* Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.

***Device* Cycling Program**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – *Device* Cycling Program for load management of eligible electric equipment, *including central air conditioning, water heaters, generators and other qualifying equipment.* Customer eligibility to participate is determined solely by the Company. *Device Cycling Program Credits may be taken in conjunction with one another.* The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment as the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers - *Device* Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers - *Device* Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – *Device* Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – *Device* Cycling Program.

The monthly credit*(s)* for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	*$(3.20)*	*per customer per month for all billing months*
Generator Credit:	*$(22.40)*	*per customer per month for all billing months*

(Continued on Sheet No. D-17.00)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 1, 2022

Issued under authority of the Michigan Public Service Commission dated December 22, 2021 in Case No. U-20963

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(*0.015226*)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-18.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To combine and cancel tariff sheets)

First Revised Sheet No. D-19.00
Cancels Original Sheet No. D-19.00

These sheets have been cancelled and are reserved for future use:

Original Sheet No. D-20.00 is cancelled; First Revised Sheet No. D-20.00 is reserved for future use
Original Sheet No. D-21.00 is cancelled; First Revised Sheet No. D-21.00 is reserved for future use
Original Sheet No. D-22.00 is cancelled; First Revised Sheet No. D-22.00 is reserved for future use
First Revised Sheet No. D-23.00 is cancelled; Second Revised Sheet No. D-23.00 is reserved for future use
Original Sheet No. D-24.00 is cancelled; First Revised Sheet No. D-24.00 is reserved for future use
Original Sheet No. D-25.00 is cancelled; First Revised Sheet No. D-25.00 is reserved for future use
Original Sheet No. D-26.00 is cancelled; First Revised Sheet No. D-26.00 is reserved for future use
First Revised Sheet No. D-27.00 is cancelled; Second Revised Sheet No. D-27.00 is reserved for future use
First Revised Sheet No. D-28.00 is cancelled; Second Revised Sheet No. D-28.00 is reserved for future use
Original Sheet No. D-29.00 is cancelled; First Revised Sheet No. D-29.00 is reserved for future use
Original Sheet No. D-30.00 is cancelled; First Revised Sheet No. D-30.00 is reserved for future use
Original Sheet No. D-31.00 is cancelled; First Revised Sheet No. D-31.00 is reserved for future use
First Revised Sheet No. D-32.00 is cancelled; Second Revised Sheet No. D-32.00 is reserved for future use
Original Sheet No. D-33.00 is cancelled; First Revised Sheet No. D-33.00 is reserved for future use
Original Sheet No. D-34.00 is cancelled; First Revised Sheet No. D-34.00 is reserved for future use
First Revised Sheet No. D-35.00 is cancelled; Second Revised Sheet No. D-35.00 is reserved for future use

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2021

Issued under authority of the
Michigan Public Service Commission
dated December 17, 2020
in Case No. U-20697

RESIDENTIAL SMART HOURS RATE RSH

Availability:

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$*0.058841*	$*0.041238*	$*0.100079*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak – Summer	$*0.087901*	$*0.061354*	$*0.149255*	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak – Winter	$*0.057841*	$*0.038554*	$*0.096395*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak – Winter	$*0.062689*	$*0.043857*	$*0.106546*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.059076*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-37.00)

M.P.S.C. No. 14 – Electric **Third Revised Sheet No. D-37.00**
Consumers Energy Company **Cancels Second Revised Sheet No. D-37.00**
(To revise Device Cycling Program)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Monthly Rate: (Contd)

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principle Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Peak Power Savers:

Customers can elect to participate in the *Device* Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the *total credit earned under the Device* Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers.

***Device* Cycling Program:**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – *Device* Cycling Program for load management of eligible electric equipment, *including central air conditioning, water heaters, generators and other qualifying equipment*. Customer eligibility to participate in this program is determined solely by the Company. *Device Cycling Program Credits may be taken in conjunction with one another.* The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers – *Device* Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers – *Device* Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

(Continued on Sheet No. D-38.00)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2022

Issued under authority of the
Michigan Public Service Commission
dated December 22, 2021
in Case No. U-20963

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Device Cycling Program: (Contd)

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – *Device* Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – *Device* Cycling Program.

The monthly credit*(s)* for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit	*$(3.20)*	*per customer per month for all billing months*
Generator Credit:	*$(22.40)*	*per customer per month for all billing months*

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(*0.015226*)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Distributed Generation Program)

Second Revised Sheet No. D-39.00
Cancels First Revised Sheet No. D-39.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2021

Issued under authority of the
Michigan Public Service Commission
dated December 17, 2020
in Case No. U-20697

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	$*0.044644*	$*0.025656*	$*0.070300*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	$*0.068618*	$*0.042143*	$*0.110761*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	$*0.087901*	$*0.061354*	$*0.149255*	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	$*0.049569*	$*0.028881*	$*0.078450*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	$*0.065438*	$*0.040268*	$*0.105706*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	$*0.062689*	$*0.043857*	$*0.106546*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.059076*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-41.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the household will be billed under the Residential Summer On-Peak Basic Rate or the Residential Smart Hours Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: These charges are applicable to Full Service Customers.

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Peak Power Savers:

Customers can elect to participate in the *Device* Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the *total credit earned under the Device* Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.

(Continued on Sheet No. D-42.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

***Device* Cycling Program:**

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – *Device* Cycling Program for load management of eligible electric equipment, *including central air conditioning, water heaters, generators and other qualifying equipment.* Customer eligibility to participate in this program is determined solely by the Company. *Device Cycling Program Credits may be taken in conjunction with one another.* The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers – *Device* Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers – *Device* Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – *Device* Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – *Device* Cycling Program.

The monthly credit*(s)* for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit:	*$(3.20)*	*per customer per month for all billing months*
Generator Credit:	*$(22.40)*	*per customer per month for all billing months*

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Second Revised Sheet No. D-43.00
Cancels First Revised Sheet No. D-43.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Critical Peak Price:

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. Customers must have a transmitting meter to participate in Peak Power Savers.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(*0.015226*)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2022

Issued under authority of the
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RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-44.10
Cancels Third Revised Sheet No. D-44.10

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.063176*	$ *0.040126*	$*0.103302*	per kWh for the first 600 kWh per month during the billing months of June - September
$ *0.082252*	$ *0.049223*	$*0.131475*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$ *0.058608*	$ *0.040126*	$*0.098734*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.059076*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-44.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise RIA and LIAC)

Third Revised Sheet No. D-44.20
Cancels Second Revised Sheet No. D-44.20

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the *total* household *income does not exceed 150% of the Federal Poverty level,* a credit shall be applied during all billing months. *The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:*

1. *A Home Heating Credit energy draft*
2. *State Emergency Relief*
3. *Assistance from a Michigan Energy Assistance Program (MEAP)*
4. *Medicaid*

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision *(RIA)* shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(*8.00*) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need *and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:*

1. Customers *whose* total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who *have received assistance from a Michigan Energy Assistance Program (MEAP)*
3. Customers who have received a Home Heating Credit *energy draft*
4. *A* State Emergency Relief *program*
5. Medicaid
6. *Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.*

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA).

(Continued on Sheet No. D-44.30)

Issued June 15, 2021 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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Issued under authority of the Michigan Public Service Commission dated June 9, 2021 in Case No. U-21043

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page)

First Revised Sheet No. D-44.30
Cancels Original Sheet No. D-44.30

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.20)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

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Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2021

Issued under authority of the
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rates)

Third Revised Sheet No. D-45.00
Cancels Second Revised Sheet No. D-45.00

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.057748*	$*0.031308*	$*0.089056*	per kWh for all kWh during the billing months of June-September
$*0.058918*	$*0.032564*	$*0.091482*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.046251*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Third Revised Sheet No. D-46.00
Cancels Second Revised Sheet No. D-46.00

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $(*0.000747*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

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GENERAL SERVICE SECONDARY RATE GS
(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.*2*., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.*2*.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.*2*., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.039055*	$*0.019268*	$*0.058323*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	$*0.058524*	$*0.029857*	$*0.088381*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	$*0.075629*	$*0.035935*	$*0.111564*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	$*0.049938*	$*0.028107*	$*0.078045*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	$*0.063327*	$*0.037621*	$*0.100948*	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.046251*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-49.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rate)

Third Revised Sheet No. D-49.00
Cancels Second Revised Sheet No. D-49.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit: $(*0.000747*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

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President and Chief Executive Officer,
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Third Revised Sheet No. D-50.00
Cancels Second Revised Sheet No. D-50.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $(*0.017094*) per kWh for all kWh

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-50.10)

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GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$*8.40*	$*11.69*	$*20.09*	per kW for all kW of Peak Demand during the billing months of June-September
$*6.47*	$*10.41*	$*16.88*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.037842*	per kWh for all kWh during the billing months of June-September
$*0.038330*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$*0.74*	per kW for all kW of Peak Demand
Distribution Charge:	$0.033256	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-52.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-51.00)

Monthly Rate: (Contd)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	***Penalty***
0.800 to 0.849	*0.50%*
0.750 to 0.799	*1.00%*
0.700 to 0.749	*2.00%*
Below 0.700	*3% first 2 months*

Adjustment for Power Factor shall not be applied when the Peak Demand is based a Minimum Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Peak Demand:

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-53.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: $ (*0.000598*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-54.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.056134*	$*0.027796*	$*0.083930*	per kWh for all kWh during the billing months of June-September
$*0.057255*	$*0.028896*	$*0.086151*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.055617*	$*0.027455*	$*0.083072*	per kWh for all kWh during the billing months of June-September
$*0.056726*	$*0.028542*	$*0.085268*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.054883*	$*0.027036*	$*0.081919*	per kWh for all kWh during the billing months of June-September
$*0.055977*	$*0.028106*	$*0.084083*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $*0.017343* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $*0.010250* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $*0.005968* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$ (*0.001483*)	per kWh for all kWh
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$ (*0.001018*)	per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit:	$(0.000492)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, or (v) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-59.00
Cancels Second Revised Sheet No. D-59.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.94*	$*6.30*	$*18.24*	per kW of On-Peak Billing Demand during the billing months of June-September
$*11.07*	$5.44	$*16.51*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$7.62	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.09*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.038163*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.024315*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.030767*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.028461*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-60.00
Cancels Second Revised Sheet No. D-60.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service customers. (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.79*	$*6.25*	$*18.04*	per kW of On-Peak Billing Demand during the billing months of June-September
$*10.94*	$5.40	$*16.34*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$7.52	per kW of On-Peak Billing Demand during the billing months of June-September
$7.01	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.037853*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.024117*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.030517*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.028229*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.61*	$*6.17*	$*17.78*	per kW of On-Peak Billing Demand during the billing months of June-September
$*10.77*	$5.33	$*16.10*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$*7.41*	per kW of On-Peak Billing Demand during the billing months of June-September
$6.90	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.037382*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.023817*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.030137*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.027878*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

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Third Revised Sheet No. D-61.00
Cancels Second Revised Sheet No. D-61.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*4.71*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$2.48	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.69*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

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Fourth Revised Sheet No. D-62.00
Cancels Third Revised Sheet No. D-62.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$(0.61)	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$(*0.41*)	per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
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Second Revised Sheet No. D-63.00
Cancels First Revised Sheet No. D-63.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $(*0.000240*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

(Continued on Sheet No. D-64.00)

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M.P.S.C. No. 14 – Electric **Third Revised Sheet No. D-64.00**
Consumers Energy Company **Cancels Second Revised Sheet No. D-64.00**
(To revise Interruptible Service Provision)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate. All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may *adjust* the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company’s ability to implement emergency electrical procedures as described in the Company’s Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer’s annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer’s contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company’s control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company’s Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

(Continued on Sheet No. D-65.00)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2022

Issued under authority of the
Michigan Public Service Commission
dated December 22, 2021
in Case No. U-20963

M.P.S.C. No. 14 – Electric **First Revised Sheet No. D-65.00**
Consumers Energy Company **Cancels Original Sheet No. D-65.00**
(To reformat page and revise GI2 Provision)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

Interruptible Service Provision – Market-Price Option (GI2):

Availability:

This provision is available to any Full Service GPD customer account willing to *designate* at least 3,000 kW of On-Peak Billing Demand as *Defined Interruptible Capacity*. The Company reserves the right to limit the amount of *designated interruptible* load *available to any single customer*, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to *designate* less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm* Capacity and *Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December *10th* of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

Issued December 30, 2020 by
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-66.00
Cancels Third Revised Sheet No. D-66.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.024111*	per kWh for all kWh during the billing months of June-September
	$*0.024284*	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 2 (CVL 2)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.022910*	per kWh for all kWh during the billing months of June-September
	$*0.022264*	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 1 (CVL 1)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.020497*	per kWh for all kWh during the billing months of June-September
	$*0.019632*	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	0.999%
Customer Voltage Level 2	1.324%	2.338%
Customer Voltage Level 3	3.175%	7.605%

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise meter loss percentages)

First Revised Sheet No. D-67.00
Cancels Original Sheet No. D-67.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-68.00)

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Garrick J. Rochow,
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Jackson, Michigan

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M.P.S.C. No. 14 – Electric **Second Revised Sheet No. D-68.00**
Consumers Energy Company **Cancels First Revised Sheet No. D-68.00**
(To reformat page and add Distributed Generation Program)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-69.00)

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LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate: (Contd)

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, or (vi)at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. *Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.*

This rate is not available for Standby service with generators that exceed 550kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 12:00 PM and 7:00 PM to 11:00 PM
Mid-Peak Hours:	12:00 PM to 2:00 PM and 5:00 PM to 7:00 PM
High-Peak Hours:	2:00 PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to 2:00 PM and 9:00 PM to 12:00 AM
Mid-Peak Hours:	2:00 PM to 4:00 PM and 7:00 PM to 9:00 PM
High-Peak Hours:	4:00 PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-71.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-71.00
Cancels Second Revised Sheet No. D-71.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.042207*	$*0.023029*	$*0.065236*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.059721*	$*0.034094*	$*0.093815*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.076399*	$*0.042451*	$*0.118850*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.085234*	$*0.044469*	$*0.129703*	per kWh during the calendar months of June-September
Off-Peak -Winter	$*0.052396*	$*0.020680*	$*0.073076*	per kWh during the calendar months of October-May
Mid-Peak -Winter	$*0.057312*	$*0.024029*	$*0.081341*	per kWh during the calendar months of October-May
High-Peak -Winter	$*0.060120*	$*0.024039*	$*0.084159*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.041810*	$*0.022747*	$*0.064557*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.059156*	$*0.033676*	$*0.092832*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.075678*	$*0.041931*	$*0.117609*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.084438*	$*0.043924*	$*0.128362*	per kWh during the calendar months of June-September
Off-Peak - Winter	$*0.051922*	$*0.020427*	$*0.072349*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.056789*	$*0.023734*	$*0.080523*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.059575*	$*0.023744*	$*0.083319*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.041253*	$*0.022400*	$*0.063653*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.058366*	$*0.033162*	$*0.091528*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.074670*	$*0.041291*	$*0.115961*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.083317*	$*0.043254*	$*0.126571*	per kWh during the calendar months of June-September
Off-Peak - Winter	$*0.051243*	$*0.020115*	$*0.071358*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.056045*	$*0.023372*	$*0.079417*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.058796*	$*0.023382*	$*0.082178*	per kWh during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*4.71*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$2.48	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.69*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.61) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.41*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: $ (0.000240) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-73.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate *may* require a written contract with a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Nature of Service)

Third Revised Sheet No. D-74.00
Cancels Second Revised Sheet No. D-74.00

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing or former metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

The Company may elect to install devices that can enable direct load management, power metering, data collection, near real-time data communication and internet based monitoring. There shall be no cost to the customer associated with the system equipment or installation of the system equipment. The Company reserves the right to remove the system equipment if the customer moves from Rate EIP to another primary rate.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

Critical Peak Event Determination

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources and Load Management Measures - Stage 1. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at the greater of 150% of the High Peak Energy Charge or the average market price during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

(Continued on Sheet No. D-75.00)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2022

Issued under authority of the
Michigan Public Service Commission
dated December 22, 2021
in Case No. U-20963

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.042296*	$*0.004379*	$*0.046675*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.063684*	$*0.006842*	$*0.070526*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.079646*	$*0.008319*	$*0.087965*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.087138*	$*0.008511*	$*0.095649*	per kWh during the calendar months of June-September
Critical Peak-Summer				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	$*0.051873*	$*0.003690*	$*0.055563*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.058570*	$*0.004211*	$*0.062781*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.061458*	$*0.004268*	$*0.065726*	per kWh during the calendar months of October-May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-76.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-76.00
Cancels Second Revised Sheet No. D-76.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$*0.041898*	$*0.004325*	$*0.046223*	per kWh during the calendar months of June-September
Low-Peak - Summer	$*0.063082*	$*0.006758*	$*0.069840*	per kWh during the calendar months of June-September
Mid-Peak - Summer	$*0.078895*	$*0.008217*	$*0.087112*	per kWh during the calendar months of June-September
High-Peak - Summer	$*0.086324*	$*0.008406*	$*0.094730*	per kWh during the calendar months of June-September
Critical Peak - Summer				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak - Winter	$*0.051406*	$*0.003645*	$*0.055051*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.058041*	$*0.004159*	$*0.062200*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.060906*	$*0.004215*	$*0.065121*	per kWh during the calendar months of October - May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 1(CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.041340*	$*0.004259*	$*0.045599*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.062239*	$*0.006655*	$*0.068894*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.077843*	$*0.008092*	$*0.085935*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.085179*	$*0.008278*	$*0.093457*	per kWh during the calendar months of June-September
Critical Peak-Summer				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak - Winter	$*0.050735*	$*0.003589*	$*0.054324*	per kWh during the calendar months of October - May
Mid-Peak - Winter	$*0.057284*	$*0.004096*	$*0.061380*	per kWh during the calendar months of October - May
High-Peak - Winter	$*0.060112*	$*0.004151*	$*0.064263*	per kWh during the calendar months of October - May
Critical Peak-Winter				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $*4.71* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $2.48 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $*0.69* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-77.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(0.61) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.41*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-77.00)

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate *may* require a written contract with a minimum term of one year.

LARGE ECONOMIC DEVELOPMENT RATE LED

Availability:

At the Company's discretion, the Large Economic Development Rate is available to (1) new Full Service primary electric customers locating permanent operations within the Company's service territory or (2) existing Full Service primary customers expanding their permanent operations.

The minimum new or expanded incremental electric service required to contract under the Large Economic Development Rate is 35,000 kW. This rate requires a written contract specifying the terms of the electric service. Upon mutual agreement between the customer and the Company, up to 60 months from the effective date of the contract may be granted for the customer to meet the contracted amount.

This rate is not available to a new customer resulting from a change in ownership of an existing establishment located within the Company's service area. However, if a change in ownership occurs after the customer contracts for service under this rate, the successor may be allowed to fulfill the remainder of the contract.

Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities served by the Company, for standby service, for new or expanded service for resale or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

Terms and Conditions:

This rate requires a contract term, the minimum term under this rate is fifteen (15) years from the date initial service is provided under this rate, extending thereafter from month-to-month until terminated by mutual consent or on twelve months' written notice by either party.

If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:

Up to 50% of the contract term	100%
More than 50 to 60% of the contract term	83%
More than 60 to 70% of the contract term	67%
More than 70 to 80% of the contract term	50%
More than 80 to 90% of the contract term	33%
More than 90% to 99.9% of the contract term	17%

For existing customers expanding their operations, the Company will install, operate, and maintain the metering equipment necessary to measure the incremental load to be billed under this rate. The customer will provide the Company with access to its metering equipment. The Company is not obligated to extend, expand, or rearrange its facilities if it determines the existing facilities are adequate to serve the customer's load.

(Continued on Sheet D-78.20)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:		
Customer Voltage Level 1	$4.73	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$4.81	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$4.86	per kW of On-Peak Billing Demand for all calendar months
Transmission Charge:		
Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh).

Line losses applied to Energy Charge	
Voltage Level 1	2.90%
Voltage Level 2	4.16%
Voltage Level 3	4.99%

(Continued on Sheet No. D-78.30)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

First Revised Sheet No. D-78.30
Cancels Original Sheet No. D-78.30

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$*0.69*	per kW of Maximum Demand
Customer Voltage Level 2:	$2.48	per kW of Maximum Demand
Customer Voltage Level 3:	$*4.71*	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.61) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $*(0.41)* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision: (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-78.50)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update reference to Rate RSM)

First Revised Sheet No. D-79.00
Cancels Original Sheet No. D-79.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

Availability:

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company**:**

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company**:**

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Power Plant Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company's electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

"Standby" service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer's generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

"Standby Demand" is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this Rate Schedule.

This rate is not available to Retail Open Access.

Nature of Service

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B., Parallel Operation Requirements. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-Hertz, single-phase or three-phase (as governed by Rule B8., Electric Interconnection and Net Metering Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 Volts or less but equal to or greater than 2,400 Volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-82.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-82.00
Cancels Second Revised Sheet No. D-82.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of *1.92%* plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	0.999%
Customer Voltage Level 2	1.324%	2.338%
Customer Voltage Level 3	3.175%	7.605%

Delivery Standby Charges

System Access Charge:

Generator that does not meet or exceed load:	$100.00	per generator installation per month
Generator that meets or exceeds load:	$200.00	per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge:	$*4.71*	per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$2.48	per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$*0.69*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-83.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Third Revised Sheet No. D-83.00
Cancels Second Revised Sheet No. D-83.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(0.61) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.41*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-84.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $ (*0.69*) per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year.

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

Availability:

Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.

A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.

The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.

Contracted Capacity and Annual Nominations:

The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.

The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.

At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.

(Continued on Sheet D-84.20)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.

Monthly Rate:

System Access Charge:	*Fixed charge per billing month as specified in the customer's written agreement for electric service*

Power Supply Charges:

Capacity Charge:	*$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Reserved Capacity Charge:	*$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Excess Capacity Charge:	*$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level*
Interruptible Credit:	*Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge*
Energy Charge:	*The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service*

(Continued on Sheet No. D-84.30)

M.P.S.C. No. 14 – Electric **Original Sheet No. D-84.30**
Consumers Energy Company
(To add Rate LTILRR)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.20)

Power Supply Charges: (Contd)

Excess Energy Charge:	*$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges*

Transmission Charges:

Transmission Charge:	*Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service*

Delivery Charges:

Distribution Charges:	*Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00

Interruptible Service Provision

The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO issues a Maximum Generation Emergency Event Step 2b order or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-84.40)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Annual Power Test Requirement)

First Revised Sheet No. D-84.40
Cancels Original Sheet No. D-84.40

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.30)

Interruptible Service Provision (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.

A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-84.50)

Issued October 15, 2021 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after September 25, 2021

Issued under authority of the
Michigan Public Service Commission
dated September 24, 2021
in Case No. U-21038

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.40)

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.

Definitions Applicable to the Long Term Industrial Load Retention Rate:

Annual Forecast Capacity
Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.

Annual Load Factor
Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.

Average Demand
Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.

Capacity Charge
The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.

Energy Charge
The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.

Excess Capacity
The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.

(Continued on Sheet No. D-84.60)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.50)

Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)

Firm Contracted Capacity
The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.

Interruptible Peak Billing Demand
The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.

Interruptible Service Capacity
Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.

Interval Data Meters
Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.

Maximum Contracted Capacity
The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.

Maximum Monthly Demand
The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.

MISO Planning Year
MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.

Reserved Capacity
The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR

Site
An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.051846*	$0.000000	$*0.051846*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-86.00
Cancels Third Revised Sheet No. D-86.00

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$*0.054795*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.025444*	$0.000000	$*0.025444*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.041758*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-86.00)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule.

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines, supply the energy, control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaries, the Company shall furnish, install and own all equipment comprising the unmetered lighting system. The Company shall supply the energy, and renew and maintain the entire equipment. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be furnished, owned, installed and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company's general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

M.P.S.C. No. 14 – Electric **Original Sheet No. D-89.00**
Consumers Energy Company
(To reformat Rate Book)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall install new luminaires and associated facilities under this rate, or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.

B. At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest standard size high-pressure sodium luminaire at no cost to the customer. If requirements for installations make it necessary for the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain due to federal or state requirements, the Company shall cover the cost of the bulb and the customer shall be responsible for all other expenses as a contribution. For conversions completed with normal Company maintenance such as replacement of bulbs on a routine schedule or due to failure, then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution. If other light upgrading is also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

   Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.

C. Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company, the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.

D. Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.

E. For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.

F. For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

G. If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.

(Continued on Sheet No. D-90.00)

Issued December 13, 2019 by
Patti Poppe,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.00
Cancels Third Revised Sheet No. D-90.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-89.00)

Monthly Rate

Transitional Rates, effective *March 18, 2022* through June 30, 2022:

The charge per luminaire per month shall be

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)			Service Charge per Luminaire (4)			
Type of Luminaire	Watts	Watts Including Ballast (2)	Lumens	Non-Capacity	Capacity	Total	Fixture Charge per Luminaire (4)
Mercury Vapor (3)	100	128	3,500	$9.72	$0.00	$9.72	$3.00
Mercury Vapor (3)	175	209	7,500	13.28	0.00	13.28	3.00
Mercury Vapor (3)	250	281	10,000	16.45	0.00	16.45	3.00
Mercury Vapor (3)	400	458	20,000	*24.23*	0.00	*24.23*	3.00
Mercury Vapor (3)	700	770	35,000	37.96	0.00	37.96	3.00
Mercury Vapor (3)	1,000	1,080	50,000	*51.59*	0.00	*51.59*	3.00
High-Pressure Sodium (3)	70	83	5,000	7.74	0.00	7.74	3.00
High-Pressure Sodium	100	117	8,500	9.23	0.00	9.23	3.00
High-Pressure Sodium	150	171	14,000	11.61	0.00	11.61	3.00
High-Pressure Sodium (3)	200	247	20,000	*14.96*	0.00	*14.96*	3.00
High-Pressure Sodium	250	318	24,000	*18.07*	0.00	*18.07*	3.00
High-Pressure Sodium	400	480	45,000	*25.20*	0.00	*25.20*	3.00
Fluorescent (3)	380	470	20,000	*24.76*	0.00	*24.76*	3.00
Incandescent (3)	202	202	2,500	*12.98*	0.00	*12.98*	3.00
Incandescent (3)	305	305	4,000	17.51	0.00	17.51	3.00
Incandescent (3)	405	405	6,000	*21.90*	0.00	*21.90*	3.00
Incandescent (3)	690	690	10,000	*34.44*	0.00	*34.44*	3.00
Metal Halide (3)	150	170	9,750	*11.56*	0.00	*11.56*	3.00
Metal Halide (3)	175	210	10,500	13.33	0.00	13.33	3.00
Metal Halide (3)	250	290	15,500	*16.84*	0.00	*16.84*	3.00
Metal Halide (3)	400	460	24,000	24.33	0.00	24.33	3.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *22.6*% Power Supply Charge and a *77.4*% Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 15.6% Power Supply Charge and a 84.4% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-90.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add revise prices)

First Revised Sheet No. D-90.10
Cancels Original Sheet No. D-90.10

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after July 1, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$7.73*	*$8.07*
25-34 W	Per Light	$0.51	$0.00	$0.51	$8.09	$8.60
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$8.45	*$9.13*
45-54 W	Per Light	$0.86	$0.00	$0.86	$8.80	$9.66
55-64 W	Per Light	$1.03	$0.00	$1.03	$9.16	$10.19
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$9.51	*$10.71*
75-84 W	Per Light	$1.38	$0.00	$1.38	$9.87	$11.25
85-94 W	Per Light	$1.55	$0.00	$1.55	$10.22	$11.77
95-104 W	Per Light	*$1.72*	$0.00	*$1.72*	$10.58	*$12.30*
105-114 W	Per Light	$1.90	$0.00	$1.90	*$10.93*	*$12.83*
115-124 W	Per Light	*$2.07*	$0.00	*$2.07*	$11.29	*$13.36*
125-134 W	Per Light	*$2.24*	$0.00	*$2.24*	$11.65	*$13.89*
135-144 W	Per Light	$2.42	$0.00	$2.42	$12.00	$14.42
145-154 W	Per Light	*$2.59*	$0.00	*$2.59*	$12.36	*$14.95*
155-164 W	Per Light	*$2.76*	$0.00	*$2.76*	$12.71	*$15.47*
165-174 W	Per Light	$2.94	$0.00	$2.94	$13.07	$16.01
175-184 W	Per Light	*$3.11*	$0.00	*$3.11*	$13.42	*$16.53*
185-194 W	Per Light	*$3.28*	$0.00	*$3.28*	$13.78	*$17.06*
195-204 W	Per Light	$3.46	$0.00	$3.46	$14.14	$17.60
205-214 W	Per Light	*$3.63*	$0.00	*$3.63*	$14.49	*$18.12*
215-224 W	Per Light	*$3.80*	$0.00	*$3.80*	$14.85	*$18.65*
225-234 W	Per Light	*$3.98*	$0.00	*$3.98*	$15.20	*$19.18*
235-244 W	Per Light	*$4.15*	$0.00	*$4.15*	$15.56	*$19.71*
245-254 W	Per Light	*$4.32*	$0.00	*$4.32*	$15.91	*$20.23*
255-264 W	Per Light	*$4.50*	$0.00	*$4.50*	$16.27	*$20.77*
265-274 W	Per Light	*$4.67*	$0.00	*$4.67*	*$16.63*	$21.30
275-284 W	Per Light	*$4.84*	$0.00	*$4.84*	$16.98	*$21.82*
285-294 W	Per Light	*$5.02*	$0.00	*$5.02*	$17.34	*$22.36*
295-304 W	Per Light	*$5.19*	$0.00	*$5.19*	$17.69	*$22.88*
305-314 W	Per Light	*$5.36*	$0.00	*$5.36*	$18.05	*$23.41*
315-324 W	Per Light	*$5.54*	$0.00	*$5.54*	$18.40	*$23.94*
325-334 W	Per Light	*$5.71*	$0.00	*$5.71*	$18.76	*$24.47*
335-344 W	Per Light	*$5.88*	$0.00	*$5.88*	*$19.12*	*$25.00*
345-354 W	Per Light	*$6.06*	$0.00	*$6.06*	$19.47	*$25.53*
355-364 W	Per Light	*$6.23*	$0.00	*$6.23*	*$19.83*	$26.06
365-374 W	Per Light	*$6.40*	$0.00	*$6.40*	$20.18	*$26.58*
375-384 W	Per Light	*$6.57*	$0.00	*$6.57*	$20.54	*$27.11*
385-394 W	Per Light	*$6.75*	$0.00	*$6.75*	$20.89	*$27.64*
395-404 W	Per Light	*$6.92*	$0.00	*$6.92*	$21.25	*$28.17*
405-414 W	Per Light	*$7.09*	$0.00	*$7.09*	*$21.61*	*$28.70*
415-424 W	Per Light	*$7.27*	$0.00	*$7.27*	$21.96	*$29.23*
425-434 W	Per Light	*$7.44*	$0.00	*$7.44*	*$22.32*	*$29.76*
435-444 W	Per Light	*$7.61*	$0.00	*$7.61*	*$22.67*	*$30.28*
445-454 W	Per Light	*$7.79*	$0.00	*$7.79*	*$23.03*	*$30.82*
455-464 W	Per Light	*$7.96*	$0.00	*$7.96*	$23.38	*$31.34*
465-474 W	Per Light	*$8.13*	$0.00	*$8.13*	$23.74	*$31.87*
475-484 W	Per Light	*$8.31*	$0.00	*$8.31*	*$24.10*	*$32.41*

(Continued on Sheet No. D-90.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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Consumers Energy Company
(To revise rates)

First Revised Sheet No. D-90.20
Cancels Original Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after July 1, 2022:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$4.73*	*$5.07*
25-34 W	Per Light	$0.51	$0.00	$0.51	$5.09	$5.60
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$5.45	*$6.13*
45-54 W	Per Light	$0.86	$0.00	$0.86	$5.80	$6.66
55-64 W	Per Light	$1.03	$0.00	$1.03	$6.16	$7.19
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$6.51	*$7.71*
75-84 W	Per Light	$1.38	$0.00	$1.38	$6.87	$8.25
85-94 W	Per Light	$1.55	$0.00	$1.55	$7.22	$8.77
95-104 W	Per Light	*$1.72*	$0.00	*$1.72*	$7.58	*$9.30*
105-114 W	Per Light	$1.90	$0.00	$1.90	*$7.93*	*$9.83*
115-124 W	Per Light	*$2.07*	$0.00	*$2.07*	$8.29	*$10.36*
125-134 W	Per Light	*$2.24*	$0.00	*$2.24*	$8.65	*$10.89*
135-144 W	Per Light	$2.42	$0.00	$2.42	$9.00	$11.42
145-154 W	Per Light	*$2.59*	$0.00	*$2.59*	$9.36	*$11.95*
155-164 W	Per Light	*$2.76*	$0.00	*$2.76*	$9.71	*$12.47*
165-174 W	Per Light	$2.94	$0.00	$2.94	$10.07	$13.01
175-184 W	Per Light	*$3.11*	$0.00	*$3.11*	$10.42	*$13.53*
185-194 W	Per Light	*$3.28*	$0.00	*$3.28*	$10.78	*$14.06*
195-204 W	Per Light	$3.46	$0.00	$3.46	$11.14	$14.60
205-214 W	Per Light	*$3.63*	$0.00	*$3.63*	$11.49	*$15.12*
215-224 W	Per Light	*$3.80*	$0.00	*$3.80*	$11.85	*$15.65*
225-234 W	Per Light	*$3.98*	$0.00	*$3.98*	$12.20	*$16.18*
235-244 W	Per Light	*$4.15*	$0.00	*$4.15*	$12.56	*$16.71*
245-254 W	Per Light	*$4.32*	$0.00	*$4.32*	$12.91	*$17.23*
255-264 W	Per Light	*$4.50*	$0.00	*$4.50*	$13.27	*$17.77*
265-274 W	Per Light	*$4.67*	$0.00	*$4.67*	*$13.63*	$18.30
275-284 W	Per Light	*$4.84*	$0.00	*$4.84*	$13.98	*$18.82*
285-294 W	Per Light	*$5.02*	$0.00	*$5.02*	$14.34	*$19.36*
295-304 W	Per Light	*$5.19*	$0.00	*$5.19*	$14.69	*$19.88*
305-314 W	Per Light	*$5.36*	$0.00	*$5.36*	$15.05	*$20.41*
315-324 W	Per Light	*$5.54*	$0.00	*$5.54*	$15.40	*$20.94*
325-334 W	Per Light	*$5.71*	$0.00	*$5.71*	$15.76	*$21.47*
335-344 W	Per Light	*$5.88*	$0.00	*$5.88*	*$16.12*	*$22.00*
345-354 W	Per Light	*$6.06*	$0.00	*$6.06*	$16.47	*$22.53*
355-364 W	Per Light	*$6.23*	$0.00	*$6.23*	*$16.83*	$23.06
365-374 W	Per Light	*$6.40*	$0.00	*$6.40*	$17.18	*$23.58*
375-384 W	Per Light	*$6.57*	$0.00	*$6.57*	$17.54	*$24.11*
385-394 W	Per Light	*$6.75*	$0.00	*$6.75*	$17.89	*$24.64*
395-404 W	Per Light	*$6.92*	$0.00	*$6.92*	$18.25	*$25.17*
405-414 W	Per Light	*$7.09*	$0.00	*$7.09*	*$18.61*	*$25.70*
415-424 W	Per Light	*$7.27*	$0.00	*$7.27*	$18.96	*$26.23*
425-434 W	Per Light	*$7.44*	$0.00	*$7.44*	*$19.32*	*$26.76*
435-444 W	Per Light	*$7.61*	$0.00	*$7.61*	$19.67	*$27.28*
445-454 W	Per Light	*$7.79*	$0.00	*$7.79*	*$20.03*	*$27.82*
455-464 W	Per Light	*$7.96*	$0.00	*$7.96*	$20.38	*$28.34*
465-474 W	Per Light	*$8.13*	$0.00	*$8.13*	$20.74	*$28.87*
475-484 W	Per Light	*$8.31*	$0.00	*$8.31*	*$21.10*	*$29.41*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-91.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. *D-90.20*)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms, Surcharges, Power Supply Cost Recovery (PSCR) Factor and Power Plant Securitization Charges:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00, Surcharges shown on Nos. D-2.00 through D-5.00, PSCR Factor shown on Sheet No. D-6.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

(Continued on Sheet No. D-92.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Streetlighting Outage Credit language)

First Revised Sheet No. D-92.00
Cancels Original Sheet No. D-92.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-91.00)

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the capacity requirements in watts of the lamp(s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

Issued August 12, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after August 12, 2022

Issued under authority of the Michigan Public Service Commission dated August 11, 2022 in Case No. U-21203

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Rate GU-LED)

First Revised Sheet No. D-93.00
Cancels Original Sheet No. D-93.00

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

Nature of Service:

Company-Owned Option

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:

Company-Owned Option

Following execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company. *A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-94.00)

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2021

Issued under authority of the
Michigan Public Service Commission
dated December 17, 2020
in Case No. U-20697

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Company-Owned Conversion Credit)

Third Revised Sheet No. D-94.00
Cancels Second Revised Sheet No. D-94.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December *2028* billing month:

Fixture Credit per Luminaire: $(*4.96*) per month

(Continued on Sheet No. D-94.10)

Issued January 14, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2022

Issued under authority of the
Michigan Public Service Commission
dated December 22, 2021
in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Second Revised Sheet No. D-94.10
Cancels First Revised Sheet No. D-94.10

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.00)

Monthly Rate (Contd)

Transitional Unmetered Lighting Rate GU-LED Charges, effective *March 18, 2022* through June 30, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$8.32	$8.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$8.98	$9.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$9.64	$10.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$10.31	$11.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$10.97	$12.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$11.63	$12.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$12.30	$13.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$12.96	$14.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$13.62	$15.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$14.28	$16.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$14.95	$17.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$15.61	$17.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$16.27	$18.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$16.94	$19.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$17.60	$20.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$18.26	$21.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$18.93	$22.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$19.59	$22.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$20.25	$23.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$20.92	$24.51

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$5.32	$5.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$5.98	$6.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$6.64	$7.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$7.31	$8.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$7.97	$9.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$8.63	$9.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$9.30	$10.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$9.96	$11.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$10.62	$12.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$11.28	$13.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$11.95	$14.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$12.61	$14.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$13.27	$15.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$13.94	$16.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$14.60	$17.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$15.26	$18.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$15.93	$19.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$16.59	$19.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$17.25	$20.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$17.92	$21.51

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-94.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rates)

First Revised Sheet No. D-94.20
Cancels Original Sheet No. D-94.20

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after July 1, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$7.73*	*$8.07*
25-34 W	Per Light	$0.51	$0.00	$0.51	$8.09	$8.60
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$8.45	*$9.13*
45-54 W	Per Light	$0.86	$0.00	$0.86	$8.80	$9.66
55-64 W	Per Light	$1.03	$0.00	$1.03	$9.16	$10.19
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$9.51	*$10.71*
75-84 W	Per Light	$1.38	$0.00	$1.38	$9.87	$11.25
85-94 W	Per Light	$1.55	$0.00	$1.55	$10.22	$11.77
95-104 W	Per Light	*$1.72*	$0.00	*$1.72*	$10.58	*$12.30*
105-114 W	Per Light	$1.90	$0.00	$1.90	*$10.93*	*$12.83*
115-124 W	Per Light	*$2.07*	$0.00	*$2.07*	$11.29	*$13.36*
125-134 W	Per Light	*$2.24*	$0.00	*$2.24*	$11.65	*$13.89*
135-144 W	Per Light	$2.42	$0.00	$2.42	$12.00	$14.42
145-154 W	Per Light	*$2.59*	$0.00	*$2.59*	$12.36	*$14.95*
155-164 W	Per Light	*$2.76*	$0.00	*$2.76*	$12.71	*$15.47*
165-174 W	Per Light	$2.94	$0.00	$2.94	$13.07	$16.01
175-184 W	Per Light	*$3.11*	$0.00	*$3.11*	$13.42	*$16.53*
185-194 W	Per Light	*$3.28*	$0.00	*$3.28*	$13.78	*$17.06*
195-204 W	Per Light	$3.46	$0.00	$3.46	$14.14	$17.60
205-214 W	Per Light	*$3.63*	$0.00	*$3.63*	$14.49	*$18.12*
215-224 W	Per Light	*$3.80*	$0.00	*$3.80*	$14.85	*$18.65*
225-234 W	Per Light	*$3.98*	$0.00	*$3.98*	$15.20	*$19.18*
235-244 W	Per Light	*$4.15*	$0.00	*$4.15*	$15.56	*$19.71*
245-254 W	Per Light	*$4.32*	$0.00	*$4.32*	$15.91	*$20.23*
255-264 W	Per Light	*$4.50*	$0.00	*$4.50*	$16.27	*$20.77*
265-274 W	Per Light	*$4.67*	$0.00	*$4.67*	*$16.63*	$21.30
275-284 W	Per Light	*$4.84*	$0.00	*$4.84*	$16.98	*$21.82*
285-294 W	Per Light	*$5.02*	$0.00	*$5.02*	$17.34	*$22.36*
295-304 W	Per Light	*$5.19*	$0.00	*$5.19*	$17.69	*$22.88*
305-314 W	Per Light	*$5.36*	$0.00	*$5.36*	$18.05	*$23.41*
315-324 W	Per Light	*$5.54*	$0.00	*$5.54*	$18.40	*$23.94*
325-334 W	Per Light	*$5.71*	$0.00	*$5.71*	$18.76	*$24.47*
335-344 W	Per Light	*$5.88*	$0.00	*$5.88*	*$19.12*	*$25.00*
345-354 W	Per Light	*$6.06*	$0.00	*$6.06*	$19.47	*$25.53*
355-364 W	Per Light	*$6.23*	$0.00	*$6.23*	*$19.83*	$26.06
365-374 W	Per Light	*$6.40*	$0.00	*$6.40*	$20.18	*$26.58*
375-384 W	Per Light	*$6.57*	$0.00	*$6.57*	$20.54	*$27.11*
385-394 W	Per Light	*$6.75*	$0.00	*$6.75*	$20.89	*$27.64*
395-404 W	Per Light	*$6.92*	$0.00	*$6.92*	$21.25	*$28.17*
405-414 W	Per Light	*$7.09*	$0.00	*$7.09*	*$21.61*	*$28.70*
415-424 W	Per Light	*$7.27*	$0.00	*$7.27*	$21.96	*$29.23*
425-434 W	Per Light	*$7.44*	$0.00	*$7.44*	*$22.32*	*$29.76*
435-444 W	Per Light	*$7.61*	$0.00	*$7.61*	*$22.67*	*$30.28*
445-454 W	Per Light	*$7.79*	$0.00	*$7.79*	*$23.03*	*$30.82*
455-464 W	Per Light	*$7.96*	$0.00	*$7.96*	$23.38	*$31.34*
465-474 W	Per Light	*$8.13*	$0.00	*$8.13*	$23.74	*$31.87*
475-484 W	Per Light	*$8.31*	$0.00	*$8.31*	*$24.10*	*$32.41*

(Continued on Sheet No. D-94.30)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rates)

First Revised Sheet No. D-94.30
Cancels Original Sheet No. D-94.30

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)
Universal Unmetered Streetlighting Rates, effective for service rendered on and after July 1, 2022:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$4.73*	*$5.07*
25-34 W	Per Light	$0.51	$0.00	$0.51	$5.09	$5.60
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$5.45	*$6.13*
45-54 W	Per Light	$0.86	$0.00	$0.86	$5.80	$6.66
55-64 W	Per Light	$1.03	$0.00	$1.03	$6.16	$7.19
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$6.51	*$7.71*
75-84 W	Per Light	$1.38	$0.00	$1.38	$6.87	$8.25
85-94 W	Per Light	$1.55	$0.00	$1.55	$7.22	$8.77
95-104 W	Per Light	*$1.72*	$0.00	*$1.72*	$7.58	*$9.30*
105-114 W	Per Light	$1.90	$0.00	$1.90	*$7.93*	*$9.83*
115-124 W	Per Light	*$2.07*	$0.00	*$2.07*	$8.29	*$10.36*
125-134 W	Per Light	*$2.24*	$0.00	*$2.24*	$8.65	*$10.89*
135-144 W	Per Light	$2.42	$0.00	$2.42	$9.00	$11.42
145-154 W	Per Light	*$2.59*	$0.00	*$2.59*	$9.36	*$11.95*
155-164 W	Per Light	*$2.76*	$0.00	*$2.76*	$9.71	*$12.47*
165-174 W	Per Light	$2.94	$0.00	$2.94	$10.07	$13.01
175-184 W	Per Light	*$3.11*	$0.00	*$3.11*	$10.42	*$13.53*
185-194 W	Per Light	*$3.28*	$0.00	*$3.28*	$10.78	*$14.06*
195-204 W	Per Light	$3.46	$0.00	$3.46	$11.14	$14.60
205-214 W	Per Light	*$3.63*	$0.00	*$3.63*	$11.49	*$15.12*
215-224 W	Per Light	*$3.80*	$0.00	*$3.80*	$11.85	*$15.65*
225-234 W	Per Light	*$3.98*	$0.00	*$3.98*	$12.20	*$16.18*
235-244 W	Per Light	*$4.15*	$0.00	*$4.15*	$12.56	*$16.71*
245-254 W	Per Light	*$4.32*	$0.00	*$4.32*	$12.91	*$17.23*
255-264 W	Per Light	*$4.50*	$0.00	*$4.50*	$13.27	*$17.77*
265-274 W	Per Light	*$4.67*	$0.00	*$4.67*	*$13.63*	$18.30
275-284 W	Per Light	*$4.84*	$0.00	*$4.84*	$13.98	*$18.82*
285-294 W	Per Light	*$5.02*	$0.00	*$5.02*	$14.34	*$19.36*
295-304 W	Per Light	*$5.19*	$0.00	*$5.19*	$14.69	*$19.88*
305-314 W	Per Light	*$5.36*	$0.00	*$5.36*	$15.05	*$20.41*
315-324 W	Per Light	*$5.54*	$0.00	*$5.54*	$15.40	*$20.94*
325-334 W	Per Light	*$5.71*	$0.00	*$5.71*	$15.76	*$21.47*
335-344 W	Per Light	*$5.88*	$0.00	*$5.88*	*$16.12*	*$22.00*
345-354 W	Per Light	*$6.06*	$0.00	*$6.06*	$16.47	*$22.53*
355-364 W	Per Light	*$6.23*	$0.00	*$6.23*	*$16.83*	$23.06
365-374 W	Per Light	*$6.40*	$0.00	*$6.40*	$17.18	*$23.58*
375-384 W	Per Light	*$6.57*	$0.00	*$6.57*	$17.54	*$24.11*
385-394 W	Per Light	*$6.75*	$0.00	*$6.75*	$17.89	*$24.64*
395-404 W	Per Light	*$6.92*	$0.00	*$6.92*	$18.25	*$25.17*
405-414 W	Per Light	*$7.09*	$0.00	*$7.09*	*$18.61*	*$25.70*
415-424 W	Per Light	*$7.27*	$0.00	*$7.27*	$18.96	*$26.23*
425-434 W	Per Light	*$7.44*	$0.00	*$7.44*	*$19.32*	*$26.76*
435-444 W	Per Light	*$7.61*	$0.00	*$7.61*	$19.67	*$27.28*
445-454 W	Per Light	*$7.79*	$0.00	*$7.79*	*$20.03*	*$27.82*
455-464 W	Per Light	*$7.96*	$0.00	*$7.96*	$20.38	*$28.34*
465-474 W	Per Light	*$8.13*	$0.00	*$8.13*	$20.74	*$28.87*
475-484 W	Per Light	*$8.31*	$0.00	*$8.31*	*$21.10*	*$29.41*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-95.00)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

M.P.S.C. No. 14 – Electric **Fourth Revised Sheet No. D-95.00**
Consumers Energy Company **Cancels Third Revised Sheet No. D-95.00**
(To revise Streetlighting Outage Credit language)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.30)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered LED Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered LED Lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.054118*	$*0.019589*	$*0.073707*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.021864*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-97.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-96.00)

Monthly Rate: (Contd)

Determination of kWh:

The monthly charge shall be the per kWh total of the Power Supply and Delivery Charges as shown above based on the capacity requirements in Kilowatts of the lamp(s), associated ballast(s) and control equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption. At the Company's option, such service may be metered and the metered kWh used as the basis for billing. The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

For dusk to midnight service for energy-only unmetered lighting, the monthly charge per kWh shall be 130% of the sum of the Secondary Energy Charge and Distribution Charge per kWh for secondary service. The annual kWh shall be based on the actual burning hours. The monthly kWh for billing shall be the annual kWh adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be 50% of the total kWh so calculated. The kWh for continuous, nonintermittent devices shall be 100% of the total kWh so calculated. No reduction in kWh shall be made for devices not operated 24 hours per day, or not operated every day.

The kWh of devices used for the control of school traffic, and operated not more than six hours per day during the school year only, shall be 10% of the continuous or cyclical kWh calculated.

The kWh for CATV Power Supply Units shall be 50% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The kWh for Wireless Access and Security Camera Power Supply Units shall be 100% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The Company may, at its option, install test meters for the purpose of determining the monthly kWh usage to be used for billing purposes.

(Continued on Sheet No. D-98.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-97.00)

Monthly Rate (Contd)

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, plus any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

Case No: U-21225
Utility: Consumers Energy
Date: December 21, 2021
Exhibit 13: Designees for Copies of Contracts

The Company designates a primary and secondary contact to assist with requested customer contract review. The designated contacts are:

Primary Designee:

Name: Kenneth Selander
Email: Kenneth.Selander@cmsenergy.com
Office Phone: (248) 433-5986

Secondary Designee:

Name: Sarah Jorgensen
Email: sarah.jorgensen@cmsenergy.com
Office Phone: (517) 740-1372

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 26

2027/2028 Consumers Energy Capacity Demonstration

February 22, 2024

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

Re: MPSC Case No. U-21393 – In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2027/2028 planning year as required by MCL 460.6w.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2027/2028**. A confidential version of this filing is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2024.02.22 14:59:14 -05'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion to open a docket for load serving entities in Michigan, to file their capacity demonstrations for the 2027/2028 planning year as required by MCL 460.6w.	))))))	Case No. U-21393

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

AFFIDAVIT OF SRIKANTH MADDIPATI

Srikanth Maddipati, being duly sworn, states that the following information and attached exhibits are true and accurate to the best of my reasonable knowledge and belief, regarding Consumers Energy Company's ("Consumers Energy" or the "Company") satisfaction of its Michigan capacity demonstration requirements:

1. I am the Vice President of Electric Supply for Consumers Energy. My responsibilities include, in part, overall responsibility for the Company's long-term and short-term electric supply planning, investments, and strategy. I received a Bachelor of Science Degree in Computer Engineering from the University of Michigan in 2004 and, concurrently, completed my Master of Science Degree in Engineering with a specialization in Signal Processing. I received a Master of Business Administration Degree from the Ross School of Business at the University of Michigan in 2008, where I focused on Finance and Accounting.

2. Consumers Energy is a public utility engaged in the generation, purchase, distribution, and sale of electric energy to approximately 1.9 million retail electric customers in the lower peninsula of the state of Michigan. Consumers Energy remains committed to planning

for and providing an adequate electric supply to meet the needs of Michigan homes and businesses, with reliable, flexible, and cost-effective energy. The Company's impact extends beyond supplying a commodity — Consumers Energy is a vital part of Michigan's economic, social, and environmental fabric as reflected in our Triple Bottom Line commitment to people, planet, and prosperity.

3. The information provided in this Affidavit is based on my first-hand knowledge of the Company's long-term and short-term electric supply planning, investments, and strategy. Pursuant to Section 6w of 2016 PA 341, and as required by the Michigan Public Service Commission's ("MPSC" or the "Commission") July 26, 2023 Order in Case Nos. U-21099, U-21225, and U-21393, this Affidavit is a demonstration to the Commission that the Company has sufficient electric capacity arrangements for Planning Year[1] ("PY") 2027/2028. The remainder of this Affidavit discusses the Planning Reserve Margin Requirement ("PRMR"), peak demand outlook, and the capacity resources planned to fulfill customer need.

4. Consumers Energy remains dedicated to meeting the needs of its full-service electric customers over the four-year planning period while maintaining adequate reserve margins, as detailed in this filing, with:

- Demand Response ("DR") consistent with the Company's 2021 Integrated Resource Plan ("IRP") Proposed Course of Action ("PCA") as approved in MPSC Case No. U-21090 ("IRP Settlement"). As DR programs evolve, there may be shifting of DR levels among the different programs;
- Offered capacity generated from existing resources in the applicable Michigan Zone;
- Contracted amounts of Power Purchase Agreements ("PPA") in accordance with the terms of the applicable agreements;
- Renewable capacity from existing and new resources, as identified in this filing consistent with the Company's Renewable Energy Plan and IRP PCA; and

[1] Planning Year, as defined by the Midcontinent Independent System Operator, Inc. ("MISO"), is the 12-month period commencing on June 1 of each year and concluding on May 31 of the following year.

- Continued use of existing resources including the J.H. Campbell Plant (through retirement in May 2025), D. E. Karn Units 3 and 4 (through retirement in May 2031), the Ludington Pumped Storage Plant, the newly acquired Covert Generating Plant, Zeeland and Jackson Generating Plants, the Cross Winds, Lake Winds, Gratiot Farms Wind, and Crescent Wind Energy Parks, and Heartland Wind Farm.

5. Consumers Energy plans to sufficiently serve its full-service customers with safe, affordable, reliable, and sustainable energy for the next four years and beyond. The Company's plans are outlined in the following paragraphs, covering PYs 2024/2025 through 2027/2028, and address each of the required capacity areas:

- Exhibit 1 — Utility Bundled Service Peak Demand for Michigan Midcontinent Independent System Operator, Inc. ("MISO") LRZ 7;
- Exhibit 2 — Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC);
- Exhibit 3 — Demand Response—Capacity Resources;
- Exhibit 4 — Company-Owned Electric Generation Resources (Confidential);
- Exhibit 5 — New or Upgraded Generation Owned;
- Exhibit 6 — Generation Resources Under PPA or Other Capacity Contract (Confidential); and
- Exhibit 7 — New or Upgraded Purchased Power.

6. MISO Module E Reports for PY 2023/2024:

Reports from the MISO Module E Capacity Tracking tool demonstrating the unforced[2] capacity ("UCAP") confirmed by the Company for Planning Year 2023/2024 are provided as Exhibits 8 through 11.

- Exhibit 8 — Existing Owned Generation (Confidential);
- Exhibit 9 — Demand Response Programs—Not Netted Against Load (Confidential);

[2] MISO's evaluation of Loss of Load Expectation for PY 2023/24 utilized net demonstrated capacity less the three-year Equivalent Forced Outage Rate on demand, or "EFORd." The resulting capacity value is commonly referred to as "unforced."

- Exhibit 10 — Existing Purchased Power Agreements (Confidential); and
- Exhibit 11 — Existing Transactions (Confidential).

7. Tariffs

Relevant tariffs are included in this filing as Exhibit 12. In lieu of filing a copy of the customer supply contracts with this capacity demonstration, the Company agrees to make available the customer supply contracts relevant to the Commercial and Industrial Demand Response ("DR Contracts") Program and Interruptible Service ("Rate GI") Provision for the Commission Staff's ("Staff") review upon request, without Staff retaining a copy. Exhibit 13 contains the contact information of the persons designated to make available the customer supply contracts and copies of any of the Company's PPAs for review by Staff.

8. PRMR

The capacity planning reserve margin target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to ensure that sufficient capacity exists to provide adequate electric supply in each PY period. The Company relies on MISO to determine the appropriate capacity Planning Reserve Margin ("PRM") that Consumers Energy should maintain. For PY 2024, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

MISO's seasonal construct, accepted by the Federal Energy Regulatory Commission in September 2022, introduces seasonal requirements to the Planning Resource Auction ("PRA").

As a result, MISO's LOLE study sets the system-wide capacity PRM Unforced Capacity ("PRM UCAP") and the zonal LRR for each season for the upcoming 2024/2025 PY. Under the MISO seasonal construct, the annual planning year is divided into four distinct seasons between June 1, 2024, and May 31, 2025, and for subsequent planning years moving forward. The seasons are Summer from June 1 – August 31, Fall from September 1 – November 30, Winter from December 1 – February 28, and Spring from March 1 - May 31.

On October 17, 2023, MISO determined seasonal PRM UCAP planning reserve margin targets for PY 2024/2025 of 9.0% for Summer, 14.2% for Fall, 27.4% for Winter, and 26.7% for Spring. The exhibits will be labeled by season (Summer, Fall, Winter, Spring) respectively for each season. The Company also forecasted load requirements for the 2027/2028 PY as it has done for prior capacity demonstrations. The Company will plan to meet the Company's PRMR and thus maintain resources to meet full-service customer capacity needs throughout the PY, including during peak load periods.

9. Peak Demand

The Company's historical and forecasted peak demands are shown in Exhibit 1. The values provided in Exhibit 1 are not weather-normalized. The peak demands shown in Exhibit 1 include supplying demand associated with Bundled (full-service) customers, Choice customers through Retail Open Access, and the summation of Bundled and Choice customers denoted as Service Territory peak demand.

Existing DR or Energy Waste Reduction ("EWR") resources netted against load are detailed in the section below and can be found in Exhibit 2, line 2.

The Company must plan for capacity during periods when MISO experiences its peak demand. The Company's forecast of peak bundled demand is adjusted to align with MISO's peak

demand, which requires application of a -3.96% diversity factor as shown in Exhibit 2, lines 4 and 5. The Company's forecast of peak bundled demand is also adjusted to include transmission losses, which requires application of a transmission loss factor of 4.50% as shown in Exhibit 2, line 6.

Consumers Energy plans to draw on a diverse portfolio of resources to meet its annual PRMR obligation. Those resources include utility-owned generation, long-term supply contracts, EWR, and DR resources.

10. Existing Generation — Owned

Consumers Energy currently owns, operates, and manages resources all located within Michigan and within MISO Zone 7 and plans to offer the LSE capacity from these resources in the applicable Michigan Zone throughout the four-year planning period. A summary of the Company's forecast for its owned resources — including resource type, installed capacity, and Installed Seasonal Accreditation Capacity ("ISAC") — is provided in Exhibit 2 (by category) and Exhibit 4 (by unit).

11. Existing DR or EWR Resources (Not Netted Against Load)

Consumers Energy offers a suite of Demand-Side Management programs available for residential, commercial, and industrial customer classes to deliver and manage significant peak load reductions. Existing programs offered by the Company that are not netted against load and can be offered into MISO as a capacity resource include:

- Air Conditioning Peak Cycling ("ACPC") Program;
- Commercial & Industrial Demand Response ("DR Contracts");
- Rate GI/GI 2 (DR Rate GI Reduce By/DR Rate GI Reduce to); and
- Smart Thermostat Program.

Existing Demand-Side Management programs not netted against load result in total load-modifying resources as shown in Exhibit 2, line 18. Exhibit 3 provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio. Exhibit 9 summarizes these DR programs with data from the MISO Module E Report for PY 2023/2024.

Transmission losses and the PRM (on a UCAP basis) were applied per MISO standard practice for registered DR capacity, as detailed in (BPM-011-r29).[3]

12. Existing DR or EWR Resources (Netted Against Load)

Existing DR and EWR programs netted against load include Dynamic Peak Pricing, Residential Summer on-peak rate RSP, EWR, and Conservation Voltage Reduction (Exhibit 2, line 2, less new DR or EWR resources netted against load). Growth in these Demand-Side Management programs (in combination with those not netted against load) is consistent with the IRP Settlement. The applicable tariff sheets are included in Exhibit 12.

13. New or Upgraded Utility-Owned Generation

New or upgraded utility-owned generation planned for 2024 through 2027 includes new renewable resources in accordance with the Company's Renewable Energy Plan and the IRP Settlement. Details for these resources including planned in-service dates, expected regulatory approval dates, and expected dates for a MISO Generator Interconnection Agreement can be found in Exhibit 5. The addition of these resources in the Company's capacity planning projections are reflected in the annual values shown in Exhibit 2 (in combination with existing units) and Exhibit 4 (by individual unit) and are based on the construction and Commercial Operation Dates identified in Exhibit 5.

[3] https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

14. New DR or EWR Resources (Not Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would not be netted against load.

15. New DR or EWR Resources (Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would be netted against load.

16. Existing Generation Capacity Contracts

The Company has a number of PPAs in place for the purchase of energy, capacity, and renewable energy credits. The majority of Consumers Energy's PPAs are sourced within Michigan and within MISO Zone 7—the exception being the Heritage Garden Wind Farm, which is located in MISO Zone 2. The Company has several contracts in place with facilities that meet, or are expected to meet, the requirements of Qualifying Facilities, in accordance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"), that will terminate from 2023 to 2027. Exhibit 6 presents a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations. New PPAs where there were existing PURPA facilities are identified on Exhibit 6.

17. New or Upgraded Purchased Power

The Company's New or Upgraded Purchased Power resources are presented in Exhibit 7. There are three types of resources detailed in this exhibit. First, the Company has forecasted that existing PURPA-based contracts will be replaced with new PURPA-based agreements.[4] Obligations for these contracts are projected to remain throughout the four-year planning period. The ZRCs associated with new PURPA-based contracts are identified in Exhibit 6, line 41.

[4] Except the contract with Hillman Power Company, which includes a provision for the supplier to decommission the plant at the end of the current contract, as approved by the Commission in MPSC Case No. U-20496.

Second, the Company has contracted PPAs for new solar PURPA capacity per the Settlement Agreement in Case No. U-20615 ("PURPA Settlement"). Exhibits 6 and 7 present a forecast of the PURPA Settlement solar projects expected to achieve commercial operation through PY 2027. Because interconnection agreements and full construction schedules for many of these resources are not yet finalized, the expected construction dates presented in Exhibit 7 are subject to change. Finally, Exhibit 6, line 2, and Exhibit 7, line 1, show the details for the remainder of the 200 ZRCs to be awarded from tranche 2 of the One-Time Solicitation as agreed to in the IRP Settlement.

Consumers Energy plans to maintain the contracted amounts of these PPAs as shown in the attached exhibits and in accordance with the terms of the applicable agreements throughout the four-year planning period.

18. Forward ZRC Contracts

The Company has no forward ZRC contracts in PYs 2024 through 2027.

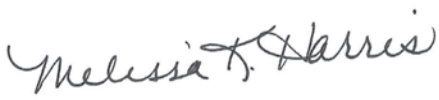
19. Planning Resource Auction Purchases

The Company projects Planning Resource Auction purchases for the PY 2025 as shown in Exhibit 2, line 33.

If sworn as a witness, I would testify as set forth above.

Srikanth Maddipati

Subscribed and sworn to before me this 22nd day of February 2024.



Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

SUMMER
EXHIBITS 1-11

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 1 of 11

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Summer Season

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2023-24**	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**
		Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	8,067	8,458	8,435	8,595	8,646
2	Choice, Coincident to Service Territory	549	449	439	486	483
3	Bundled (line 1 - line 2)	7,518	8,009	7,997	8,109	8,163
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	7,204	8,147	8,125	8,279	8,328
5	Choice, Coincident to Service Territory	543	433	423	468	466
6	Bundled (line 4 - line 5)	6,662	7,714	7,702	7,810	7,862

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 2 of 11

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Summer Season

Line	(a)	(b) PY 2024-25	(c) PY 2025-26	(d) PY 2026-27	(e) PY 2027-28
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	8,009	7,997	8,109	8,163
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	980	1,064	1,163	1,196
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,029	6,933	6,945	6,967
4	Load Diversity Factor coincident to MISO, %.	96.32%	96.32%	96.32%	96.32%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,770	6,678	6,690	6,710
6	Transmission Losses, %	3.60%	3.60%	3.60%	3.60%
7	Planning Reserve Margin % UCAP Basis	9.00%	8.30%	8.80%	9.00%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,645	7,492	7,541	7,578
9	Company Owned, In-State, Non-Intermittent, ZRC	5,404	4,298	4,577	4,620
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	153	153	353	500
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	13	13	13	13
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,589	4,482	4,962	5,150
	\				
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	572	634	656	663
19	PPA, In-State, Non-Intermittent, ZRC	1,554	1,591	1,563	1,512
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	31	31	27	23
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	217	480	555	705
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	21	37	41	40
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	3	8	10
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	176	233	275	275
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,999	2,374	2,467	2,565
32	Net Load Switching, ZRC	-	-	-	-
33	Planned Auction Purchases, ZRC	-	1	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	8,160	7,492	8,085	8,379
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	515	(0)	545	801

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 3 of 11

Exhibit 3 - Demand Response - Capacity Resources - Summer Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
11	**PY 2024-SAC**	Air Conditioning Peak Cycling(ACPC)	44	6	50
12		Rate EIP	-	-	-
13		DR CONTRACTS	220	28	248
14		C&I DR 10	-	-	-
15		DR RATE GI REDUCE BY	15	2	17
16		DR RATE GI REDUCE TO	185	24	209
17		Smart Thermostat Program (STP)	42	5	47
18		Business STP	-	-	-
19					-
20					-
21	**Total Demand Response - Capacity Resources PY 2024-2025 (ZRC)**				571.8
22	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	65	8	73
23		Rate EIP	5	1	6
24		DR CONTRACTS	220	27	247
25		C&I DR 10	-	-	-
26		DR RATE GI REDUCE BY	15	2	17
27		DR RATE GI REDUCE TO	185	23	208
28		Smart Thermostat Program (STP)	68	8	76
29		Business STP	7.0	1	7.9
30					-
31					-
32	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				634.4
33	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	68	9	77
34		Rate EIP	10	1	11
35		DR CONTRACTS	220	28	248
36		C&I DR 10	-	-	-
37		DR RATE GI REDUCE BY	15	2	17
38		DR RATE GI REDUCE TO	185	24	209
39		Smart Thermostat Program (STP)	75	10	85
40		Business STP	9.0	1	10.1
41					-
42					-
43	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				656.4
	PY 2027-SAC	Air Conditioning Peak Cycling(ACPC)	68	9	77
		Rate EIP	15	2	17
		DR CONTRACTS	220	28	248
		C&I DR 10	-	-	-
		DR RATE GI REDUCE BY	15	2	17
		DR RATE GI REDUCE TO	185	24	209
		Smart Thermostat Program (STP)	75	10	85
		Business STP	9.0	1	10.2
					-
					-
	Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)				663.3

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 5 of 11

Exhibit 5 - New or Upgraded Generation Owned - Summer Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	Heartland Wind Farm	Wind	201	18.10%	36	12/31/2023	complete	complete	complete	complete	
2	Muskegon Solar	Solar	250	50.00%	125	12/31/2025	complete	complete	August 2023	December 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2025	complete	complete	October 2022	November 2025 (Estimated)	
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/7/2026	complete	complete	Q2 2025	October 2026 (Estimated)	
5	IRP Settlement Storage	Battery Storage	75	95.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q2 2024 Submittal	Q4 2024	Q2 2025	December 2026	
7	Sunfish Solar	Solar	309	50.00%	155	12/31/2025	complete (Contract)	September 2024	Q2 2024 (Provisional GIA)	Q4 2025	
8	250 MW 2025 Solar - Owned	Solar	250	50.00%	125	6/1/2026	December 2024	Q4 2024	Q2 2025	Q2 2026	

Source:
MISO LOLE report: 2024-25 Pooled EFORd Class Averages

Notes:
[1] Battery solicitation entry have not yet been assigned to a MISO queue cycle. Dates are estimated.

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy
Date: February 22, 2024
Exhibit: 7 of 11

Exhibit 7 - New or Upgraded Purchased Power - Summer Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	IRP settlement 200 ZRC intermittent solicitation - 50% storag	Storage	110.5	95.00%	105	June 2025	TBD	TBD	TBD	TBD	TBD
2	Addle	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	March 2025
3	Allegheny Solar	Solar	11	50.00%	5	January 2025	Complete	n/a	n/a	April 2024	December 2024
4	Aluminum Solar	Solar	8	50.00%	4	July 2025	Complete	n/a	n/a	September 2024	June 2025
5	Blue Elk Solar I	Solar	20	50.00%	10	June 2025	Complete	n/a	n/a	October 2023	November 2024
6	Blue Elk Solar II	Solar	10	50.00%	5	April 2024	Complete	n/a	n/a	May 2023	March 2024
7	Blue Elk Solar III	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
8	Blue Elk Solar IV	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
9	Blue Elk Solar VII	Solar	12	50.00%	6	November 2023	Complete	n/a	n/a	March 2023	October 2023
10	Byrne Solar	Solar	5	50.00%	3	November 2023	Complete	n/a	n/a	November 2022	October 2023
11	Cereal City	Solar	100	50.00%	50	December 2023	Complete	Complete	Complete	March 2022	December 2023
12	Copenhagen	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	December 2024
13	Greenstone Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
14	Freshwater Solar, LLC	Solar	300.0	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
15	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	June 2025	March 2026
16	Hogan Solar	Solar	12	50.00%	6	February 2025	Complete	n/a	n/a	July 2024	December 2024
17	Holly	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
18	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
19	Johnsfield Solar	Solar	10	50.00%	5	March 2025	Complete	n/a	n/a	June 2024	December 2024
20	Lake City Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
21	Lightfoot Solar	Solar	10	50.00%	5	December 2023	Complete	n/a	n/a	September 2022	October 2023
22	Midcontinent Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
23	Morey Road Solar	Solar	2	50.00%	1	July 2024	Complete	Complete	n/a	January 2023	June 2024
24	Olivier	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2015	December 2025
25	Puck	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	December 2025
26	River Fork Solar	Solar	100	50.00%	50	March 2024	Complete	Complete	Complete	November 2021	March 2024
27	Shipsterns Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
28	Shoreline Solar	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
29	Sunbelievable	Solar	12	50.00%	6	March 2025	Complete	n/a	n/a	June 2024	February 2025
30	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
31	Surrey Road Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
32	Thorn Lake	Solar	20	50.00%	10	May 2025	Complete	n/a	September 2024	April 2025	December 2024
33	Tibbits Energy Storage	Storage	100	95.00%	95	May 2025	TBD	TBD	TBD	December 2024	May 2025
34	Wilford Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
35											
36											
37											
38											
39											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

FALL
EXHIBITS 1-11

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 1 of 11

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Fall Season

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2023-24**	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**
		Actual	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	8,067	7,322	7,336	7,504	7,555
2	Choice, Coincident to Service Territory	549	531	525	516	506
3	Bundled (line 1 - line 2)	7,518	6,791	6,811	6,988	7,049
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	8,033	7,224	7,238	7,403	7,453
5	Choice, Coincident to Service Territory	525	524	518	509	499
6	Bundled (line 4 - line 5)	7,509	6,700	6,720	6,894	6,954

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice
service throughout the forecast period unless there is a
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 2 of 11

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Fall Season

Line	(a)	(b) PY 2024-25	(c) PY 2025-26	(d) PY 2026-27	(e) PY 2027-28
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,791	6,811	6,988	7,049
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	825	921	999	1,032
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,966	5,890	5,989	6,017
4	Load Diversity Factor coincident to MISO, %.	98.66%	98.66%	98.66%	98.66%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,886	5,811	5,909	5,937
6	Transmission Losses, %	2.90%	2.90%	2.90%	2.90%
7	Planning Reserve Margin % UCAP Basis	14.20%	15.80%	16.30%	15.60%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,916	6,925	7,071	7,062
9	Company Owned, In-State, Non-Intermittent, ZRC	5,332	4,081	4,235	4,278
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	192	192	517	663
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	14	13	13	13
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,555	4,303	4,782	4,971
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	232	236	242	248
19	PPA, In-State, Non-Intermittent, ZRC	1,518	1,546	1,515	1,627
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	32	32	27	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	265	526	601	601
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	3	3	3	3
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	3	8	10
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	164	231	276	276
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,982	2,341	2,431	2,542
32	Net Load Switching, ZRC	-	-	-	-
33	Planned Auction Purchases, ZRC	-	44	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	7,768	6,925	7,456	7,761
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	851	(0)	384	699

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 3 of 11

Fall Season Exhibit 3 - Demand Response - Capacity Resources - Fall Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (UCAP)	(e) Total ZRC per Program Name
12	**PY 2024-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
13		Rate EIP	-	-	-
14		DR CONTRACTS	-	-	-
15		C&I DR 10	-	-	-
16		DR RATE GI REDUCE BY	15	3	18
17		DR RATE GI REDUCE TO	182	32	214
18		Small Business DPP	-	-	-
19		Smart Thermostat Program (STP)	-	-	-
20		Business STP	-	-	-
21					-
22					-
23	**Total Demand Response - Capacity Resources PY 2024-2025 (ZRC)**				231.6
24	**PY 2025-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
25		Rate EIP	5	1	6
26		DR CONTRACTS	-	-	-
27		C&I DR 10	-	-	-
28		DR RATE GI REDUCE BY	15	3	18
29		DR RATE GI REDUCE TO	182	31	212
30		Small Business DPP	-	-	-
31		Smart Thermostat Program (STP)	-	-	-
32		Business STP	-	-	-
33			0		0
34					-
35	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				236.4
36	**PY 2026-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
37		Rate EIP	10	2	12
38		DR CONTRACTS	-	-	-
39		C&I DR 10	-	-	-
40		DR RATE GI REDUCE BY	15	3	18
41		DR RATE GI REDUCE TO	182	31	212
42		Small Business DPP	-	-	-
43		Smart Thermostat Program (STP)	-	-	-
44		Business STP	-	-	-
45					-
46					-
47	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				242.3
48	**PY 2027-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
49		Rate EIP	15	3	18
50		DR CONTRACTS	-	-	-
51		C&I DR 10	-	-	-
52		DR RATE GI REDUCE BY	15	3	18
53		DR RATE GI REDUCE TO	182	31	212
54		Small Business DPP	-	-	-
55		Smart Thermostat Program (STP)	-	-	-
56		Business STP	-	-	-
57					-
58					-
59	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				248.1

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 5 of 11

Exhibit 5 - New or Upgraded Generation Owned - Fall Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	Heartland Wind	Wind	201	15.60%	31	12/31/2023	complete	complete	complete	complete	
2	Muskegon Solar	Solar	250	50.00%	125	12/31/2025	complete	complete	August 2023	December 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2025	complete	complete	October 2022	November 2025 (Estimated)	
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/7/2026	complete	complete	Q2 2025	October 2026 (Estimated)	
5	IRP Settlement Storage	Battery Storage	75	95.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q2 2024 Submittal	Q4 2024	Q2 2025	December 2026	
7	Sunfish Solar	Solar	309	50.00%	155	12/31/2025	complete (Contract)	September 2024	Q2 2024 (Provisional GIA)	Q4 2025	
8	250 MW 2025 Solar - Owned	Solar	250	50.00%	125	12/1/2025	December 2024	Q4 2024	Q2 2025	Q2 2026	

Source:
MISO LOLE report: 2024-25 Pooled EFORd Class Averages

Notes:
[1] Battery solicitation entry have not yet been assigned to a MISO queue cycle. Dates are estimated.

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 7 of 11

Exhibit 7 - New or Upgraded Purchased Power - Fall Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	IRP settlement 200 ZRC intermittent solicitation - 50% stora	Storage	110.5	95.00%	105	June 2025	TBD	TBD	TBD	TBD	TBD
2	Addle	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	March 2025
3	Allegheny Solar	Solar	11	50.00%	5	January 2025	Complete	n/a	n/a	April 2024	December 2024
4	Aluminum Solar	Solar	8	50.00%	4	July 2025	Complete	n/a	n/a	September 2024	June 2025
5	Blue Elk Solar I	Solar	20	50.00%	10	June 2025	Complete	n/a	n/a	October 2023	November 2024
6	Blue Elk Solar II	Solar	10	50.00%	5	April 2024	Complete	n/a	n/a	May 2023	March 2024
7	Blue Elk Solar III	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
8	Blue Elk Solar IV	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
9	Blue Elk Solar VII	Solar	12	50.00%	6	November 2023	Complete	n/a	n/a	March 2023	October 2023
10	Byrne Solar	Solar	5	50.00%	3	November 2023	Complete	n/a	n/a	November 2022	October 2023
11	Cereal City	Solar	20	50.00%	10	December 2023	Complete	Complete	Complete	March 2022	December 2023
12	Copenhagen	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	December 2024
13	Greenstone Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
14	Freshwater Solar, LLC	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
15	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	June 2025	March 2026
16	Hogan Solar	Solar	12	50.00%	6	February 2025	Complete	n/a	n/a	July 2024	December 2024
17	Holly	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
18	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
19	Johnsfield Solar	Solar	10	50.00%	5	March 2025	Complete	n/a	n/a	June 2024	December 2024
20	Lake City Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
21	Lightfoot Solar	Solar	10	50.00%	5	December 2023	Complete	n/a	n/a	September 2022	October 2023
22	Midcontinent Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
23	Morey Road Solar	Solar	2	50.00%	1	July 2024	Complete	Complete	n/a	January 2023	June 2024
24	Olivier	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2015	December 2025
25	Puck	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	December 2025
26	River Fork Solar	Solar	100	50.00%	50	March 2024	Complete	Complete	Complete	November 2021	March 2024
27	Shipsterns Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
28	Shoreline Solar	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
29	Sunbelievable	Solar	12	50.00%	6	March 2025	Complete	n/a	n/a	June 2024	February 2025
30	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
31	Surrey Road Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
32	Thorn Lake	Solar	20	50.00%	10	May 2025	Complete	n/a	September 2024	April 2025	December 2024
33	Tibbits Energy Storage	Storage	100	95.00%	95	June 2025	TBD	TBD	TBD	December 2024	May 2025
34	Wilford Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
35											
36											
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42											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

WINTER
EXHIBITS 1-11

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 1 of 11

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Winter Season

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2023-24**	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,211	6,286	6,393	6,477	6,661
2	Choice, Coincident to Service Territory	560	296	414	411	404
3	Bundled (line 1 - line 2)	5,651	5,989	5,980	6,066	6,256
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,104	6,200	6,306	6,389	6,570
5	Choice, Coincident to Service Territory	551	292	408	406	399
6	Bundled (line 4 - line 5)	5,553	5,908	5,898	5,983	6,171

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service
throughout the forecast period unless there is a known change in
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 2 of 11

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Winter Season

Line	(a)	(b) PY 2024-25	(c) PY 2025-26	(d) PY 2026-27	(e) PY 2027-28
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	5,989	5,980	6,066	6,256
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	743	829	898	930
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,246	5,150	5,167	5,327
4	Load Diversity Factor coincident to MISO, %.	98.64%	98.64%	98.64%	98.64%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,175	5,080	5,097	5,254
6	Transmission Losses, %	4.00%	4.00%	4.00%	4.00%
7	Planning Reserve Margin % UCAP Basis	27.40%	25.10%	24.90%	25.10%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,857	6,609	6,621	6,836
9	Company Owned, In-State, Non-Intermittent, ZRC	5,685	4,471	4,499	4,503
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	309	308	328	407
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	14	13	13	13
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	6,025	4,809	4,857	4,940
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	326	327	333	340
19	PPA, In-State, Non-Intermittent, ZRC	1,549	1,449	1,449	1,388
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	28	27	22	19
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	178	484	491	506
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	4	4	4	4
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	2	7	9
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	11	28	32	32
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,770	1,993	2,006	1,959
32	Net Load Switching, ZRC	-	-	-	-
33	Planned Auction Purchases, ZRC	-	-	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	8,121	7,129	7,196	7,239
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	1,265	520	575	403

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 3 of 11

Exhibit 3 - Demand Response - Capacity Resources - Winter Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (UCAP)	(e) Total ZRC per Program Name
12	**PY 2024-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
13		Rate EIP	-	-	-
14		DR CONTRACTS	-	-	-
15		C&I DR 10	-	-	-
16		DR RATE GI REDUCE BY	15	5	20
17		DR RATE GI REDUCE TO	231	75	306
18		Small Business DPP	-	-	-
19		Smart Thermostat Program (STP)	-	-	-
20		Business STP	-	-	-
21					-
22					-
23	**Total Demand Response - Capacity Resources PY 2024-2025 (ZRC)**				326.0
24	**PY 2025-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
25		Rate EIP	5	2	7
26		DR CONTRACTS	-	-	-
27		C&I DR 10	-	-	-
28		DR RATE GI REDUCE BY	15	5	20
29		DR RATE GI REDUCE TO	231	70	300
30		Small Business DPP	-	-	-
31		Smart Thermostat Program (STP)	-	-	-
32		Business STP	-	-	-
33					-
34					-
35	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				326.9
36	**PY 2026-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
37		Rate EIP	10	3	13
38		DR CONTRACTS	-	-	-
39		C&I DR 10	-	-	-
40		DR RATE GI REDUCE BY	15	5	20
41		DR RATE GI REDUCE TO	231	69	300
42		Small Business DPP	-	-	-
43		Smart Thermostat Program (STP)	-	-	-
44		Business STP	-	-	-
45					-
46					-
47	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				332.9
48	**PY 2027-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
49		Rate EIP	15	5	20
50		DR CONTRACTS	-	-	-
51		C&I DR 10	-	-	-
52		DR RATE GI REDUCE BY	15	5	20
53		DR RATE GI REDUCE TO	231	70	300
54		Small Business DPP	-	-	-
55		Smart Thermostat Program (STP)	-	-	-
56		Business STP	-	-	-
57					-
58					-
59	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				339.9

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 5 of 11

Exhibit 5 - New or Upgraded Generation Owned - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	Heartland Wind Farm	Wind	201	53.10%	107	12/31/2023	complete	complete	August 2022	July 2024	
2	Muskegon Solar	Solar	250.0	5.00%	13	12/31/2025	complete	complete	August 2023	December 2025	
3	Mustang Mile Solar Project	Solar	150	5.00%	8	12/31/2025	complete	complete	October 2022	November 2025 (Estimated)	
4	Washtenaw Solar Project	Solar	150	5.00%	8	12/7/2026	complete	complete	Q2 2023	October 2026 (Estimated)	
5	IRP Settlement Storage	Battery Storage	75	95.00%	71	12/31/2026	N/A	N/A	Q4 2023	Q4 2024	[1]
6	Karn Solar	Solar	85	5.00%	4	12/31/2026	Q2 2024 Submittal	Q4 2024	Q2 2025	December 2026	
7	Sunfish Solar	Solar	309	5.00%	16	12/31/2025	complete (Contract)	September 2024	Q2 2024 (Provisional GIA)	Q4 2025	
8	250 MW 2025 Solar - Owned	Solar	250	5.00%	13	6/1/2026	December 2024	Q4 2024	Q2 2025	Q2 2026	

Source:
MISO LOLE report: 2024-25 Pooled EFORd Class Averages

Notes:
[1] Battery solicitation entry have not yet been assigned to a MISO queue cycle. Dates are estimated.

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 7 of 11

Exhibit 7 - New or Upgraded Purchased Power - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	IRP settlement 200 ZRC intermittent solicitation - 50% storage portion	Storage	105	95.00%	99.8	June 2025	TBD	TBD	TBD	TBD	TBD
2	Addle	Solar	20	5.00%	1.0	March 2025	Complete	n/a	n/a	June 2024	March 2025
3	Allegheny Solar	Solar	11	5.00%	0.5	January 2025	Complete	n/a	n/a	April 2024	December 2024
4	Aluminum Solar	Solar	8	5.00%	0.4	July 2025	Complete	n/a	n/a	September 2024	June 2025
5	Blue Elk Solar I	Solar	20	5.00%	1.0	June 2025	Complete	n/a	n/a	October 2023	November 2024
6	Blue Elk Solar II	Solar	10	5.00%	0.5	April 2024	Complete	n/a	n/a	May 2023	March 2024
7	Blue Elk Solar III	Solar	20	5.00%	1.0	December 2023	Complete	n/a	n/a	March 2023	November 2023
8	Blue Elk Solar IV	Solar	20	5.00%	1.0	December 2023	Complete	n/a	n/a	March 2023	November 2023
9	Blue Elk Solar VII	Solar	12	5.00%	0.6	November 2023	Complete	n/a	n/a	March 2023	October 2023
10	Byrne Solar	Solar	5	5.00%	0.3	November 2023	Complete	n/a	n/a	November 2022	October 2023
11	Cereal City	Solar	20	5.00%	1.0	December 2023	Complete	Complete	Complete	March 2022	December 2023
12	Copenhagen	Solar	20	5.00%	1.0	March 2025	Complete	n/a	n/a	June 2024	December 2024
13	Greenstone Solar, LLC	Solar	20	5.00%	1.0	October 2023	Complete	n/a	n/a	November 2022	September 2023
14	Freshwater Solar, LLC	Solar	300	5.00%	15.0	June 2027	Complete	Complete	Complete	Complete	May 2027
15	Heartwood Solar	Solar	150	5.00%	7.5	March 2026	Complete	Complete	Complete	June 2025	March 2026
16	Hogan Solar	Solar	12	5.00%	0.6	February 2025	Complete	n/a	n/a	July 2024	December 2024
17	Holly	Solar	0.2	5.00%	0.0	December 2025	Complete	n/a	n/a	March 2025	November 2025
18	Jackson County Solar	Solar	125	5.00%	6.3	May 2025	Complete	Complete	Complete	September 2023	May 2025
19	Johnsfield Solar	Solar	10	5.00%	0.5	March 2025	Complete	n/a	n/a	June 2024	December 2024
20	Lake City Solar	Solar	2	5.00%	0.1	July 2024	Complete	n/a	n/a	January 2023	June 2024
21	Lightfoot Solar	Solar	10	5.00%	0.5	December 2023	Complete	n/a	n/a	September 2022	October 2023
22	Midcontinent Solar, LLC	Solar	20	5.00%	1.0	October 2023	Complete	n/a	n/a	November 2022	September 2023
23	Morey Road Solar	Solar	2	5.00%	0.1	July 2024	Complete	Complete	n/a	January 2023	June 2024
24	Olivier	Solar	20	5.00%	1.0	December 2025	Complete	n/a	n/a	March 2015	December 2025
25	Puck	Solar	20	5.00%	1.0	December 2025	Complete	n/a	n/a	March 2025	December 2025
26	River Fork Solar	Solar	100	5.00%	5.0	March 2024	Complete	Complete	Complete	November 2021	March 2024
27	Shipsterns Solar	Solar	20	5.00%	1.0	November 2023	Complete	n/a	n/a	September 2022	October 2023
28	Shoreline Solar	Solar	20	5.00%	1.0	December 2025	Complete	n/a	n/a	March 2025	November 2025
29	Sunbelievable	Solar	12	5.00%	0.6	March 2025	Complete	n/a	n/a	June 2024	February 2025
30	Surbrook Solar	Solar	10	5.00%	0.5	September 2024	Complete	n/a	n/a	July 2023	March 2024
31	Surrey Road Solar	Solar	2	5.00%	0.1	July 2024	Complete	n/a	n/a	January 2023	June 2024
32	Thorn Lake	Solar	20	5.00%	1.0	May 2025	Complete	n/a	September 2024	April 2025	December 2024
33	Tibbits Energy Storage	Storage	100	95.00%	95.0	June 2025	TBD	TBD	TBD	December 2024	May 2025
34	Wilford Solar	Solar	20	5.00%	1.0	November 2023	Complete	n/a	n/a	September 2022	October 2023
35											
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37											
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39											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

SPRING
EXHIBITS 1-11

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 1 of 11

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Spring Season

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)
		PY 2023-24	**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,414	6,428	6,632	6,648	6,815
2	Choice, Coincident to Service Territory	558	362	455	462	441
3	Bundled (line 1 - line 2)	5,856	6,066	6,177	6,186	6,374
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,304	6,342	6,543	6,559	6,723
5	Choice, Coincident to Service Territory	548	357	449	456	435
6	Bundled (line 4 - line 5)	5,755	5,984	6,094	6,103	6,289

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 2 of 11

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Spring Season

Line	(a)	(b) PY 2024-25	(c) PY 2025-26	(d) PY 2026-27	(e) PY 2027-28
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,066	6,177	6,186	6,374
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	772	855	880	915
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,294	5,322	5,306	5,459
4	Load Diversity Factor coincident to MISO, %.	98.66%	98.66%	98.66%	98.66%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,223	5,251	5,235	5,386
6	Transmission Losses, %	2.90%	2.90%	2.90%	2.90%
7	Planning Reserve Margin % UCAP Basis	26.70%	24.10%	23.90%	24.10%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,809	6,705	6,674	6,878
9	Company Owned, In-State, Non-Intermittent, ZRC	5,147	4,061	4,215	4,258
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	178	178	503	649
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	20	19	19	19
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,362	4,274	4,754	4,943
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	308	308	315	321
19	PPA, In-State, Non-Intermittent, ZRC	1,582	1,487	1,487	1,433
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	34	29	25	23
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	256	618	693	843
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	4	4	4	4
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	3	9	11
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	173	245	290	290
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,050	2,386	2,509	2,605
32	Net Load Switching, ZRC	-	-	-	-
33	Planned Auction Purchases, ZRC	-	-	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	7,719	6,969	7,577	7,869
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	910	264	903	991

Case No.: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 3 of 11

Exhibit 3 - Demand Response - Capacity Resources - Spring Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (UCAP)	(e) Total ZRC per Program Name
12	**PY 2024-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
13		Rate EIP	-	-	-
14		DR CONTRACTS	-	-	-
15		C&I DR 10	-	-	-
16		DR RATE GI REDUCE BY	15	5	20
17		DR RATE GI REDUCE TO	221	67	288
18		Small Business DPP	-	-	-
19		Smart Thermostat Program (STP)	-	-	-
20		Business STP	-	-	-
21					-
22					-
23	**Total Demand Response - Capacity Resources PY 2024-2025 (ZRC)**				308.1
24	**PY 2025-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
25		Rate EIP	5	1	6
26		DR CONTRACTS	-	-	-
27		C&I DR 10	-	-	-
28		DR RATE GI REDUCE BY	15	4	20
29		DR RATE GI REDUCE TO	221	61	282
30		Small Business DPP	-	-	-
31		Smart Thermostat Program (STP)	-	-	-
32		Business STP	-	-	-
33					-
34					-
35	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				308.4
36	**PY 2026-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
37		Rate EIP	10	3	13
38		DR CONTRACTS	-	-	-
39		C&I DR 10	-	-	-
40		DR RATE GI REDUCE BY	15	4	20
41		DR RATE GI REDUCE TO	221	61	282
42		Small Business DPP	-	-	-
43		Smart Thermostat Program (STP)	-	-	-
44		Business STP	-	-	-
45					-
46					-
47	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				314.6
48	**PY 2027-UCAP**	Air Conditioning Peak Cycling(ACPC)	-	-	-
49		Rate EIP	15	4	19
50		DR CONTRACTS	-	-	-
51		C&I DR 10	-	-	-
52		DR RATE GI REDUCE BY	15	4	20
53		DR RATE GI REDUCE TO	221	61	282
54		Small Business DPP	-	-	-
55		Smart Thermostat Program (STP)	-	-	-
56		Business STP	-	-	-
57					-
58					-
59	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				321.1

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 5 of 11

Exhibit 5 - New or Upgraded Generation Owned - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	Heartland Wind Farm	Wind	201	18.00%	36	12/31/2023	complete	complete	complete	complete	
2	Muskegon Solar	Solar	250.0	50.00%	125	12/31/2025	complete	complete	August 2023	December 2025	
3	Mustang Mile Solar Project	Solar	150.0	50.00%	75	12/31/2025	complete	complete	October 2022	November 2025 (Estimated)	[1]
4	Washtenaw Solar Project	Solar	150.0	50.00%	75	12/7/2026	complete	complete	Q2 2025	October 2026 (Estimated)	[2]
5	IRP Settlement Storage	Battery Storage	75	95.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[3]
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q2 2024 Submittal	Q4 2024	Q2 2025	December 2026	
7	Sunfish Solar	Solar	309	50.00%	155	12/31/2025	complete (Contract)	September 2024	Q2 2024 (Provisional GIA)	Q4 2025	
8	250 MW 2025 Solar - Owned	Solar	250	50.00%	125	12/1/2025	December 2024	Q4 2024	Q2 2025	Q2 2026	

Source:
MISO LOLE report: 2024-25 Pooled EFORd Class Averages

Notes:
[1] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[2] Construction Start and End Date subject to Invenergy successfully obtaining SLUP byQ2 2023
[3] Battery solicitation entry have not yet been assigned to a MISO queue cycle. Dates are estimated.

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit: 7 of 11

Exhibit 7 - New or Upgraded Purchased Power - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	IRP settlement 200 ZRC intermittent solicitation - 50% stora	Storage	110.5	95.00%	105	June 2025	TBD	TBD	TBD	TBD	TBD
2	Addle	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	March 2025
3	Allegheny Solar	Solar	11	50.00%	5	January 2025	Complete	n/a	n/a	April 2024	December 2024
4	Aluminum Solar	Solar	8	50.00%	4	July 2025	Complete	n/a	n/a	September 2024	June 2025
5	Blue Elk Solar I	Solar	20	50.00%	10	June 2025	Complete	n/a	n/a	October 2023	November 2024
6	Blue Elk Solar II	Solar	10	50.00%	5	April 2024	Complete	n/a	n/a	May 2023	March 2024
7	Blue Elk Solar III	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
8	Blue Elk Solar IV	Solar	20	50.00%	10	December 2023	Complete	n/a	n/a	March 2023	November 2023
9	Blue Elk Solar VII	Solar	12	50.00%	6	November 2023	Complete	n/a	n/a	March 2023	October 2023
10	Byrne Solar	Solar	5	50.00%	3	November 2023	Complete	n/a	n/a	November 2022	October 2023
11	Cereal City	Solar	20	50.00%	10	December 2023	Complete	Complete	Complete	March 2022	December 2023
12	Copenhagen	Solar	20	50.00%	10	March 2025	Complete	n/a	n/a	June 2024	December 2024
13	Greenstone Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
14	Freshwater Solar, LLC	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
15	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	June 2025	March 2026
16	Hogan Solar	Solar	12	50.00%	6	February 2025	Complete	n/a	n/a	July 2024	December 2024
17	Holly	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
18	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
19	Johnsfield Solar	Solar	10	50.00%	5	March 2025	Complete	n/a	n/a	June 2024	December 2024
20	Lake City Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
21	Lightfoot Solar	Solar	10	50.00%	5	December 2023	Complete	n/a	n/a	September 2022	October 2023
22	Midcontinent Solar, LLC	Solar	20	50.00%	10	October 2023	Complete	n/a	n/a	November 2022	September 2023
23	Morey Road Solar	Solar	2	50.00%	1	July 2024	Complete	Complete	n/a	January 2023	June 2024
24	Olivier	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2015	December 2025
25	Puck	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	December 2025
26	River Fork Solar	Solar	100	50.00%	50	March 2024	Complete	Complete	Complete	November 2021	March 2024
27	Shipsterns Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
28	Shoreline Solar	Solar	20	50.00%	10	December 2025	Complete	n/a	n/a	March 2025	November 2025
29	Sunbelievable	Solar	12	50.00%	6	March 2025	Complete	n/a	n/a	June 2024	February 2025
30	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
31	Surrey Road Solar	Solar	2	50.00%	1	July 2024	Complete	n/a	n/a	January 2023	June 2024
32	Thorn Lake	Solar	20	50.00%	10	May 2025	Complete	n/a	September 2024	April 2025	December 2024
33	Tibbits Energy Storage	Solar	100	95.00%	95	June 2025	TBD	TBD	TBD	December 2024	May 2025
34	Wilford Solar	Solar	20	50.00%	10	November 2023	Complete	n/a	n/a	September 2022	October 2023
35											
36											
37											
38											
39											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBITS 12 & 13

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ 0.070713	$ 0.032567	$0.103280	per kWh for Off-Peak kWh between June 1 and September 30
$ 0.109931	$ 0.048453	$0.158384	per kWh for On-Peak kWh between June 1 and September 30
$ 0.069821	$ 0.025374	$0.095195	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.064152	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

(Continued on Sheet No. D-15.00)

M.P.S.C. No. 14 – Electric **Third Revised Sheet No. D-15.00**
Consumers Energy Company **Cancels Second Revised Sheet No. D-15.00**
(To revise Senior Citizen Provision)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-16.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Peak Power Savers:

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.

Device Cycling Program

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Device Cycling Program for load management of eligible electric equipment, including air conditioning, water heaters, generators and other qualifying equipment. Customer eligibility to participate is determined solely by the Company. Device Cycling Program Credits may be taken in conjunction with one another, except for the Generator Credit which cannot be taken in conjunction with any other Device Cycling Program credit(s). The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment as the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers - Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers - Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$(*1.88*)	per customer per month for all billing months
Generator Credit:	$(*12.99*)	per customer per month for all billing months

(Continued on Sheet No. D-17.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. *In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.*

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. *Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.*

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. *Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.*

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(*0.014702*)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-18.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To combine and cancel tariff sheets)

First Revised Sheet No. D-19.00
Cancels Original Sheet No. D-19.00

These sheets have been cancelled and are reserved for future use:

Original Sheet No. D-20.00 is cancelled; First Revised Sheet No. D-20.00 is reserved for future use
Original Sheet No. D-21.00 is cancelled; First Revised Sheet No. D-21.00 is reserved for future use
Original Sheet No. D-22.00 is cancelled; First Revised Sheet No. D-22.00 is reserved for future use
First Revised Sheet No. D-23.00 is cancelled; Second Revised Sheet No. D-23.00 is reserved for future use
Original Sheet No. D-24.00 is cancelled; First Revised Sheet No. D-24.00 is reserved for future use
Original Sheet No. D-25.00 is cancelled; First Revised Sheet No. D-25.00 is reserved for future use
Original Sheet No. D-26.00 is cancelled; First Revised Sheet No. D-26.00 is reserved for future use
First Revised Sheet No. D-27.00 is cancelled; Second Revised Sheet No. D-27.00 is reserved for future use
First Revised Sheet No. D-28.00 is cancelled; Second Revised Sheet No. D-28.00 is reserved for future use
Original Sheet No. D-29.00 is cancelled; First Revised Sheet No. D-29.00 is reserved for future use
Original Sheet No. D-30.00 is cancelled; First Revised Sheet No. D-30.00 is reserved for future use
Original Sheet No. D-31.00 is cancelled; First Revised Sheet No. D-31.00 is reserved for future use
First Revised Sheet No. D-32.00 is cancelled; Second Revised Sheet No. D-32.00 is reserved for future use
Original Sheet No. D-33.00 is cancelled; First Revised Sheet No. D-33.00 is reserved for future use
Original Sheet No. D-34.00 is cancelled; First Revised Sheet No. D-34.00 is reserved for future use
First Revised Sheet No. D-35.00 is cancelled; Second Revised Sheet No. D-35.00 is reserved for future use

RESIDENTIAL SMART HOURS RATE RSH

Availability:

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$0.070713	$0.032567	$0.103280	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak – Summer	$0.109931	$0.048453	$0.158384	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak – Winter	$0.068024	$0.024562	$0.092586	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak – Winter	$0.077952	$0.027940	$0.105892	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.064152	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

(Continued on Sheet No. D-36.10)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the *Principal* Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-37.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.10)

Monthly Rate: (Contd)

Peak Power Savers:

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers.

Device Cycling Program:

A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Device Cycling Program for load management of eligible electric equipment, including air conditioning, water heaters, generators and other qualifying equipment. Customer eligibility to participate in this program is determined solely by the Company. Device Cycling Program Credits may be taken in conjunction with one another, except for the Generator Credit which cannot be taken with any other Device Cycling Program credit(s). The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers – Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers – Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit	$(*1.88*)	per customer per month for all billing months
Generator Credit:	$(*12.99*)	per customer per month for all billing months

(Continued on Sheet No. D-38.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. *In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.*

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. *Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.*

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. *Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.*

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(*0.014702*)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C5.7., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

Seventh Revised Sheet No. D-40.00
Cancels Sixth Revised Sheet No. D-40.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	$0.058836	$0.022366	$0.081202	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	$0.079331	$0.036740	$0.116071	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	$0.109931	$0.048453	$0.158384	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	$0.058632	$0.019376	$0.078008	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	$0.076394	$0.027016	$0.103410	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	$0.077952	$0.027940	$0.105892	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.064152	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

(Continued on Sheet No. D-40.50)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-41.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. *D-40.50*)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the *separately metered electric vehicle* will be billed under the Residential *Nighttime Savers* Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of *50* amperes or *9.6 kW*.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: These charges are applicable to Full Service Customers.

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Peak Power Savers:

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's incremental energy savings earned under the Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program. The Company reserves the right to call test events between October 1 and May 31 for customers participating in Peak Power Savers Programs.

Device Cycling Program:
A customer in a single family residence who is taking service from the Company may be eligible to participate in the Company's voluntary Peak Power Savers – Device Cycling Program for load management of eligible electric equipment, including air conditioning, water heaters, generators and other qualifying equipment. Customer eligibility to participate in this program is determined solely by the Company. Device Cycling Program Credits may be taken in conjunction with one another*, except for the Generator Credit which cannot be taken with any other Device Cycling Program credit(s).* The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company. The Company will install the required equipment at the customer's premises which will allow Load Management upon signal from the Company. When Load Management equipment is installed at a premises, future customers will be auto-enrolled into the Peak Power Savers – Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Peak Power Savers – Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service.

(Continued on Sheet No. D-42.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Device Cycling Program: (Contd)

Load Management may occur any day of the week including weekends between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day. Load Management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load Management may only occur outside of the hours of 7:00 AM and 8:00 PM during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a Load Management event for one Load Management event during the June through September months in any one calendar year for the balance of the hours left in that Load Management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Peak Power Savers – Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit:	$(*1.88*)	per customer per month for all billing months
Generator Credit:	$(*12.99*)	per customer per month for all billing months

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Peak Power Savers: (Contd)

Critical Peak Price:

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. *Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.*

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(*0.014702*)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C5.7., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, *except as provided for below.*

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.069821*	$ *0.025374*	$*0.095195*	per kWh for the first 600 kWh per month during the billing months of June - September
$ *0.109931*	$ *0.048453*	$*0.158384*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$ *0.069821*	$ *0.025374*	$*0.095195*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.064152	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-44.30)

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.20)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges:	**These charges are applicable to Full Service and Retail Open Access customers.**	
Senior Citizen Credit:	$(4.00)	per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$0.077182	$0.029502	$0.106684	per kWh for all kWh during the billing months of June-September
$0.069458	$0.020650	$0.090108	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.044692	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit: $(*0.000802*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, (vii) *service under the Demand Response Program or (viii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.059105	$0.019194	$0.078299	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	$0.079861	$0.029742	$0.109603	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	$0.108991	$0.035796	$0.144787	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	$0.060081	$0.016727	$0.076808	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	$0.076637	$0.022389	$0.099026	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.044692	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

(Continued on Sheet No. D-49.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit:	$(*0.000802*)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $(*0.017799*) per kWh for all kWh

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) *service under the Demand Response Program or (vii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$17.01	$8.09	$25.10	per kW for all kW of Peak Demand during the billing months of June-September
$10.53	$7.20	$17.73	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.032069	per kWh for all kWh during the billing months of June-September
$0.031261	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	$0.034591	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

(Continued on Sheet No. D-52.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-51.00)

Monthly Rate: (Contd)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	***Penalty***
0.800 to 0.849	*0.50%*
0.750 to 0.799	*1.00%*
0.700 to 0.749	*2.00%*
Below 0.700	*3% first 2 months*

Adjustment for Power Factor shall not be applied when the Peak Demand is based a Minimum Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Peak Demand:

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-53.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit: $ (*0.000647*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. *D-53.50*)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-54.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. *D-53.50*)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, (v) *service under the Demand Response Program or (vi)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.076550*	$*0.025915*	$*0.102465*	per kWh for all kWh during the billing months of June-September
$*0.069002*	$*0.018140*	$*0.087142*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.075761*	$*0.025563*	$*0.101324*	per kWh for all kWh during the billing months of June-September
$*0.068309*	$*0.017893*	$*0.086202*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.074800*	$*0.025180*	$*0.099980*	per kWh for all kWh during the billing months of June-September
$*0.067455*	$*0.017625*	$*0.085080*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $0.017474 per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $0.007661 per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $0.002171 per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

M.P.S.C. No. 14 – Electric **Fourth Revised Sheet No. D-57.00**
Consumers Energy Company **Cancels Third Revised Sheet No. D-57.00**
(To revise prices and add Demand Response Program)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $ (*0.001513*) per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $ (*0.001123*) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(*0.000533*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, (v) *service under the Demand Response Program or (vi)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.41*	$*9.20*	$*20.61*	per kW of On-Peak Billing Demand during the billing months of June-September
$*9.86*	$*8.53*	$*18.39*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$*7.60*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.07*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.043061*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.027033*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034405*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029550*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service customers. (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.30*	$*9.08*	$*20.38*	per kW of On-Peak Billing Demand during the billing months of June-September
$*9.77*	$*8.42*	$*18.19*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$*7.49*	per kW of On-Peak Billing Demand during the billing months of June-September
$*6.97*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.042669*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.026787*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034091*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029281*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Demand Charge:

Capacity	Non-Capacity	Total	
$*11.17*	$*8.94*	$*20.11*	per kW of On-Peak Billing Demand during the billing months of June-September
$*9.65*	$*8.29*	$*17.94*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Capacity	
$*7.38*	per kW of On-Peak Billing Demand during the billing months of June-September
$*6.87*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.042163*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.026469*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.033687*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.028934*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$5.16	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$2.62	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$0.74	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10*.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$(*0.62*)	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$(*0.46*)	per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Educational Institution Credit: $(*0.000201*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to *either (1)* contract for at least 500 kW of On-Peak Billing Demand as interruptible *or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity.* The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. *Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment.* Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may *provide* the Customer *equipment* to provide real-time, Internet-enabled power monitoring. If such monitoring is *provided*, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

Conditions of Interruption (Contd)

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

Interruptible Service Provision – Market-Price Option (GI2):

Availability:

This provision is available to any Full Service GPD customer account willing to designate at least 3,000 kW of On-Peak Billing Demand as Defined Interruptible Capacity. The Company reserves the right to limit the amount of designated interruptible load available to any single customer, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to designate less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm Capacity and Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 10th of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.040422	per kWh for all kWh during the billing months of June-September
	$0.038216	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 2 (CVL 2)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.038803	per kWh for all kWh during the billing months of June-September
	$0.035411	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 1 (CVL 1)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.031935	per kWh for all kWh during the billing months of June-September
	$0.029184	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	1.073%
Customer Voltage Level 2	1.336%	2.365%
Customer Voltage Level 3	3.299%	7.342%

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos*. D-7.00 *and D-7.10* as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-68.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-69.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate: (Contd)

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, (vi) *service under the Demand Response Program or (vii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. *Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.*

This rate is not available for Standby service with generators that exceed 550kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 12:00 PM and 7:00 PM to 11:00 PM
Mid-Peak Hours:	12:00 PM to 2:00 PM and 5:00 PM to 7:00 PM
High-Peak Hours:	2:00 PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to 2:00 PM and 9:00 PM to 12:00 AM
Mid-Peak Hours:	2:00 PM to 4:00 PM and 7:00 PM to 9:00 PM
High-Peak Hours:	4:00 PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-71.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.055195	$0.015306	$0.070501	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.068629	$0.022660	$0.091289	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.090276	$0.028214	$0.118490	per kWh during the calendar months of June-September
High-Peak-Summer	$0.105097	$0.029557	$0.134654	per kWh during the calendar months of June-September
Off-Peak -Winter	$0.063002	$0.016313	$0.079315	per kWh during the calendar months of October-May
Mid-Peak -Winter	$0.070450	$0.018954	$0.089404	per kWh during the calendar months of October-May
High-Peak -Winter	$0.075691	$0.018962	$0.094653	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.054637	$0.015098	$0.069735	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.067921	$0.022352	$0.090273	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.089351	$0.027831	$0.117182	per kWh during the calendar months of June-September
High-Peak-Summer	$0.104032	$0.029155	$0.133187	per kWh during the calendar months of June-September
Off-Peak - Winter	$0.062369	$0.016091	$0.078460	per kWh during the calendar months of October-May
Mid-Peak - Winter	$0.069739	$0.018696	$0.088435	per kWh during the calendar months of October-May
High-Peak - Winter	$0.074933	$0.018704	$0.093637	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.053951	$0.014872	$0.068823	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.067060	$0.022017	$0.089077	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.088221	$0.027414	$0.115635	per kWh during the calendar months of June-September
High-Peak-Summer	$0.102725	$0.028718	$0.131443	per kWh during the calendar months of June-September
Off-Peak - Winter	$0.061589	$0.015850	$0.077439	per kWh during the calendar months of October-May
Mid-Peak - Winter	$0.068865	$0.018416	$0.087281	per kWh during the calendar months of October-May
High-Peak - Winter	$0.073997	$0.018424	$0.092421	per kWh during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$5.16	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$2.62	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$0.74	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

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Cancels Third Revised Sheet No. D-72.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(*0.62*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: $ (*0.000201*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. *D-72.10*)

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 20, 2023

Issued under authority of the Michigan Public Service Commission dated January 19, 2023 in Case No. U-21224

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Monthly Rate (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 500 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

(Continued on Sheet No. D-72.20)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.10)

Monthly Rate (Contd)

Interruptible Service Provision (GI): (Contd)

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	*$(7.00)*	*per kW of On-Peak Billing Demand during the billing months of June-September*
	$(6.00)	*per kW of On-Peak Billing Demand during the billing months of October-May*

(Continued on Sheet No. D-73.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. *D-72.20*)

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate may require a written contract with a minimum term of one year. *Service under this rate shall require a written contract for (i) service under the Educational Institution Service Provision, (ii) service under the Interruptible Service Provision, (iii) service under the Demand Response Program, or (iv) at the option of the Company.*

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing or former metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

The Company may elect to install devices that can enable direct load management, power metering, data collection, near real-time data communication and internet based monitoring. There shall be no cost to the customer associated with the system equipment or installation of the system equipment. The Company reserves the right to remove the system equipment if the customer moves from Rate EIP to another primary rate.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

(Continued on Sheet No. *D-74.50*)

M.P.S.C. No. 14 – Electric **Original Sheet No. D-74.50**
Consumers Energy Company
(To revise Critical Peak Event Determination and reformat page)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Critical Peak Event Determination

The Company shall call a Critical Peak Event to signal either the market price has exceeded an Economic Trigger Price or a system integrity event is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at *$1.00 per kWh* during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-75.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-75.00
Cancels Third Revised Sheet No. D-75.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. *D-74.50*)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.047201*	$*0.005284*	$*0.052485*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.063140*	$*0.008257*	$*0.071397*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.081196*	$*0.010039*	$*0.091235*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.093922*	$*0.010270*	$*0.104192*	per kWh during the calendar months of June-September
Emergency Event	*NA*	*$1.00*	*$1.00*	*per kWh for all kWh during a System Integrity Event during the calendar months of June-September*
Critical Peak-Summer *Economic Event*				the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September
Off-Peak - Winter	$*0.054481*	$*0.005748*	$*0.060229*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.062613*	$*0.006559*	$*0.069172*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.066274*	$*0.006649*	$*0.072923*	per kWh during the calendar months of October-May
Emergency Event	*NA*	*$1.00*	*$1.00*	*per kWh for all kWh during a System Integrity Event during the calendar months of October-May*
Critical Peak-Winter *Economic Event*				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak - Summer	$*0.046721*	$*0.005212*	$*0.051933*	per kWh during the calendar months of June-September
Low-Peak - Summer	$*0.062488*	$*0.008145*	$*0.070633*	per kWh during the calendar months of June-September
Mid-Peak - Summer	$*0.080362*	$*0.009902*	$*0.090264*	per kWh during the calendar months of June-September
High-Peak - Summer	$*0.092971*	$*0.010131*	$*0.103102*	per kWh during the calendar months of June-September
Emergency Event	*NA*	*$1.00*	*$1.00*	*per kWh during a System Integrity Event during the calendar months of June-September*
Critical Peak – Summer *Economic Event*				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak - Winter	$*0.053931*	$*0.005670*	$*0.059601*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.061981*	$*0.006470*	$*0.068451*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.065608*	$*0.006558*	$*0.072166*	per kWh during the calendar months of October-May
Emergency Event	*NA*	*$1.00*	*$1.00*	*per kWh during a System Integrity Event during the calendar months of October-May*
Critical Peak-Winter *Economic Event*				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May

(Continued on Sheet No. D-76.00)

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 20, 2023

Issued under authority of the
Michigan Public Service Commission
dated January 19, 2023
in Case No. U-21224

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 1(CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.046134	$0.005134	$0.051268	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.061695	$0.008023	$0.069718	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.079346	$0.009754	$0.089100	per kWh during the calendar months of June-September
High-Peak-Summer	$0.091804	$0.09979	$0.101783	per kWh during the calendar months of June-September
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak - Winter	$0.053255	$0.005585	$0.058840	per kWh during the calendar months of October-May
Mid-Peak - Winter	$0.061205	$0.006373	$0.067578	per kWh during the calendar months of October-May
High-Peak - Winter	$0.064788	$0.006460	$0.071248	per kWh during the calendar months of October-May
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of October-May
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October – May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $5.16 per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $2.62 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $0.74 per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

(Continued on Sheet No. D-77.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.62*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-77.00)

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate *may* require a written contract with a minimum term of one year.

LARGE ECONOMIC DEVELOPMENT RATE LED

Availability:

At the Company's discretion, the Large Economic Development Rate is available to (1) new Full Service primary electric customers locating permanent operations within the Company's service territory or (2) existing Full Service primary customers expanding their permanent operations.

The minimum new or expanded incremental electric service required to contract under the Large Economic Development Rate is 35,000 kW. This rate requires a written contract specifying the terms of the electric service. Upon mutual agreement between the customer and the Company, up to 60 months from the effective date of the contract may be granted for the customer to meet the contracted amount.

This rate is not available to a new customer resulting from a change in ownership of an existing establishment located within the Company's service area. However, if a change in ownership occurs after the customer contracts for service under this rate, the successor may be allowed to fulfill the remainder of the contract.

Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities served by the Company, for standby service, for new or expanded service for resale or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

Terms and Conditions:

This rate requires a contract term, the minimum term under this rate is fifteen (15) years from the date initial service is provided under this rate, extending thereafter from month-to-month until terminated by mutual consent or on twelve months' written notice by either party.

If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:

Up to 50% of the contract term	100%
More than 50 to 60% of the contract term	83%
More than 60 to 70% of the contract term	67%
More than 70 to 80% of the contract term	50%
More than 80 to 90% of the contract term	33%
More than 90% to 99.9% of the contract term	17%

For existing customers expanding their operations, the Company will install, operate, and maintain the metering equipment necessary to measure the incremental load to be billed under this rate. The customer will provide the Company with access to its metering equipment. The Company is not obligated to extend, expand, or rearrange its facilities if it determines the existing facilities are adequate to serve the customer's load.

(Continued on Sheet D-78.20)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:		
Customer Voltage Level 1	$4.73	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$4.81	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$4.86	per kW of On-Peak Billing Demand for all calendar months
Transmission Charge:		
Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh).

Line losses applied to Energy Charge	
Voltage Level 1	*3.19*%
Voltage Level 2	*4.39*%
Voltage Level 3	*5.32*%

(Continued on Sheet No. D-78.30)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$0.74	per kW of Maximum Demand
Customer Voltage Level 2:	$2.62	per kW of Maximum Demand
Customer Voltage Level 3:	$5.16	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.62) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.46) per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10.* This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision: (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credit (REC) Programs.

(Continued on Sheet No. D-78.50)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission.

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

Availability:

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company**:**

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company**:**

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation with a combined onsite nameplate capacity greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company's electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

"Standby" service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer's generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

"Standby Demand" is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this Rate Schedule.

This rate is not available to Retail Open Access.

Nature of Service

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B., Parallel Operation Requirements. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-Hertz, single-phase or three-phase (as governed by Rule B8., Interconnection and *Distributed Generation* Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 Volts or less but equal to or greater than 2,400 Volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-82.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500. If the customer fails to meet this written notice requirement, the LMP shall be increased by applying a 10% adder.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of 2.14% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	1.073%
Customer Voltage Level 2	1.336%	2.365%
Customer Voltage Level 3	3.299%	7.342%

Delivery Standby Charges

System Access Charge:

Generator that does not meet or exceed load:	$100.00	per generator installation per month
Generator that meets or exceeds load:	$200.00	per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge:	$5.16	per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge:	$2.62	per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge:	$0.74	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

(Continued on Sheet No. D-83.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.62*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.46*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. *D-83.10*)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit: $ (*0.74*) per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program.

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. *D-84.00*)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. *D-83.10*)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year. *Service under the Demand Response Program shall require a contract.*

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

Availability:

Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.

A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.

The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.

Contracted Capacity and Annual Nominations:

The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.

The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.

At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.

(Continued on Sheet D-84.20)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.

Monthly Rate:

System Access Charge:	*Fixed charge per billing month as specified in the customer's written agreement for electric service*

Power Supply Charges:

Capacity Charge:	*$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Reserved Capacity Charge:	*$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Excess Capacity Charge:	*$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level*
Interruptible Credit:	*Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge*
Energy Charge:	*The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service*

(Continued on Sheet No. D-84.30)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.20)

Power Supply Charges: (Contd)

Excess Energy Charge:	$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges

Transmission Charges:

Transmission Charge:	Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service

Delivery Charges:

Distribution Charges:	Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00

Interruptible Service Provision

The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-84.40)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.30)

Interruptible Service Provision (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.

A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-84.50)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.40)

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.

Definitions Applicable to the Long Term Industrial Load Retention Rate:

Annual Forecast Capacity
Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.

Annual Load Factor
Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.

Average Demand
Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.

Capacity Charge
The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.

Energy Charge
The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.

Excess Capacity
The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.

(Continued on Sheet No. D-84.60)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.50)

Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)

Firm Contracted Capacity
The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.

Interruptible Peak Billing Demand
The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.

Interruptible Service Capacity
Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.

Interval Data Meters
Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.

Maximum Contracted Capacity
The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.

Maximum Monthly Demand
The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.

MISO Planning Year
MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.

Reserved Capacity
The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR

Site
An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.054182*	$0.000000	$*0.054182*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$0.064240	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$0.026590	$0.000000	$0.026590	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.048956	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-86.00)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule.

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines, supply the energy, control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaries, the Company shall furnish, install and own all equipment comprising the unmetered lighting system. The Company shall supply the energy, and renew and maintain the entire equipment. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be furnished, owned, installed and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company's general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall install new luminaires and associated facilities under this rate, or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.

B. At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest standard size high-pressure sodium luminaire at no cost to the customer. If requirements for installations make it necessary for the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain due to federal or state requirements, the Company shall cover the cost of the bulb and the customer shall be responsible for all other expenses as a contribution. For conversions completed with normal Company maintenance such as replacement of bulbs on a routine schedule or due to failure, then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution. If other light upgrading is also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

   Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.

C. Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company, the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.

D. Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.

E. For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.

F. For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

G. If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.

(Continued on Sheet No. D-90.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.00
Cancels Third Revised Sheet No. D-90.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-89.00)

Monthly Rate

Transitional Rates, effective *March 18, 2022* through June 30, 2022:

The charge per luminaire per month shall be

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)						
				Service Charge per Luminaire (4)			
Type of Luminaire	Watts	Watts Including Ballast (2)	Lumens	Non-Capacity	Capacity	Total	Fixture Charge per Luminaire (4)
Mercury Vapor (3)	100	128	3,500	$9.72	$0.00	$9.72	$3.00
Mercury Vapor (3)	175	209	7,500	13.28	0.00	13.28	3.00
Mercury Vapor (3)	250	281	10,000	16.45	0.00	16.45	3.00
Mercury Vapor (3)	400	458	20,000	*24.23*	0.00	*24.23*	3.00
Mercury Vapor (3)	700	770	35,000	37.96	0.00	37.96	3.00
Mercury Vapor (3)	1,000	1,080	50,000	*51.59*	0.00	*51.59*	3.00
High-Pressure Sodium (3)	70	83	5,000	7.74	0.00	7.74	3.00
High-Pressure Sodium	100	117	8,500	9.23	0.00	9.23	3.00
High-Pressure Sodium	150	171	14,000	11.61	0.00	11.61	3.00
High-Pressure Sodium (3)	200	247	20,000	*14.96*	0.00	*14.96*	3.00
High-Pressure Sodium	250	318	24,000	*18.07*	0.00	*18.07*	3.00
High-Pressure Sodium	400	480	45,000	*25.20*	0.00	*25.20*	3.00
Fluorescent (3)	380	470	20,000	*24.76*	0.00	*24.76*	3.00
Incandescent (3)	202	202	2,500	*12.98*	0.00	*12.98*	3.00
Incandescent (3)	305	305	4,000	17.51	0.00	17.51	3.00
Incandescent (3)	405	405	6,000	*21.90*	0.00	*21.90*	3.00
Incandescent (3)	690	690	10,000	*34.44*	0.00	*34.44*	3.00
Metal Halide (3)	150	170	9,750	*11.56*	0.00	*11.56*	3.00
Metal Halide (3)	175	210	10,500	13.33	0.00	13.33	3.00
Metal Halide (3)	250	290	15,500	*16.84*	0.00	*16.84*	3.00
Metal Halide (3)	400	460	24,000	24.33	0.00	24.33	3.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *22.6*% Power Supply Charge and a *77.4*% Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 15.6% Power Supply Charge and a 84.4% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-90.10)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered
on and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *January 20, 2023*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.35*	$0.00	*$0.35*	*$8.67*	*$9.02*
25-34 W	Per Light	*$0.53*	$0.00	*$0.53*	*$9.11*	*$9.64*
35-44 W	Per Light	*$0.71*	$0.00	*$0.71*	*$9.55*	*$10.26*
45-54 W	Per Light	*$0.89*	$0.00	*$0.89*	*$10.00*	*$10.89*
55-64 W	Per Light	*$1.07*	$0.00	*$1.07*	*$10.44*	*$11.51*
65-74 W	Per Light	*$1.25*	$0.00	*$1.25*	*$10.88*	*$12.13*
75-84 W	Per Light	*$1.43*	$0.00	*$1.43*	*$11.32*	*$12.75*
85-94 W	Per Light	*$1.61*	$0.00	*$1.61*	*$11.76*	*$13.37*
95-104 W	Per Light	*$1.78*	$0.00	*$1.78*	*$12.20*	*$13.98*
105-114 W	Per Light	*$1.96*	$0.00	*$1.96*	*$12.64*	*$14.60*
115-124 W	Per Light	*$2.14*	$0.00	*$2.14*	*$13.08*	*$15.22*
125-134 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.53*	*$15.85*
135-144 W	Per Light	*$2.50*	$0.00	*$2.50*	*$13.97*	*$16.47*
145-154 W	Per Light	*$2.68*	$0.00	*$2.68*	*$14.41*	*$17.09*
155-164 W	Per Light	*$2.86*	$0.00	*$2.86*	*$14.85*	*$17.71*
165-174 W	Per Light	*$3.04*	$0.00	*$3.04*	*$15.29*	*$18.33*
175-184 W	Per Light	*$3.22*	$0.00	*$3.22*	*$15.73*	*$18.95*
185-194 W	Per Light	*$3.40*	$0.00	*$3.40*	*$16.17*	*$19.57*
195-204 W	Per Light	*$3.58*	$0.00	*$3.58*	*$16.62*	*$20.20*
205-214 W	Per Light	*$3.76*	$0.00	*$3.76*	*$17.06*	*$20.82*
215-224 W	Per Light	*$3.94*	$0.00	*$3.94*	*$17.50*	*$21.44*
225-234 W	Per Light	*$4.12*	$0.00	*$4.12*	*$17.94*	*$22.06*
235-244 W	Per Light	*$4.30*	$0.00	*$4.30*	*$18.38*	*$22.68*
245-254 W	Per Light	*$4.48*	$0.00	*$4.48*	*$18.82*	*$23.30*
255-264 W	Per Light	*$4.65*	$0.00	*$4.65*	*$19.26*	*$23.91*
265-274 W	Per Light	*$4.83*	$0.00	*$4.83*	*$19.71*	*$24.54*
275-284 W	Per Light	*$5.01*	$0.00	*$5.01*	*$20.15*	*$25.16*
285-294 W	Per Light	*$5.19*	$0.00	*$5.19*	*$20.59*	*$25.78*
295-304 W	Per Light	*$5.37*	$0.00	*$5.37*	*$21.03*	*$26.40*
305-314 W	Per Light	*$5.55*	$0.00	*$5.55*	*$21.47*	*$27.02*
315-324 W	Per Light	*$5.73*	$0.00	*$5.73*	*$21.91*	*$27.64*
325-334 W	Per Light	*$5.91*	$0.00	*$5.91*	*$22.35*	*$28.26*
335-344 W	Per Light	*$6.09*	$0.00	*$6.09*	*$22.80*	*$28.89*
345-354 W	Per Light	*$6.27*	$0.00	*$6.27*	*$23.24*	*$29.51*
355-364 W	Per Light	*$6.45*	$0.00	*$6.45*	*$23.68*	*$30.13*
365-374 W	Per Light	*$6.63*	$0.00	*$6.63*	*$24.12*	*$30.75*
375-384 W	Per Light	*$6.81*	$0.00	*$6.81*	*$24.56*	*$31.37*
385-394 W	Per Light	*$6.99*	$0.00	*$6.99*	*$25.00*	*$31.99*
395-404 W	Per Light	*$7.17*	$0.00	*$7.17*	*$25.44*	*$32.61*
405-414 W	Per Light	*$7.35*	$0.00	*$7.35*	*$25.89*	*$33.24*
415-424 W	Per Light	*$7.52*	$0.00	*$7.52*	*$26.33*	*$33.85*
425-434 W	Per Light	*$7.70*	$0.00	*$7.70*	*$26.77*	*$34.47*
435-444 W	Per Light	*$7.88*	$0.00	*$7.88*	*$27.21*	*$35.09*
445-454 W	Per Light	*$8.06*	$0.00	*$8.06*	*$27.65*	*$35.71*
455-464 W	Per Light	*$8.24*	$0.00	*$8.24*	*$28.09*	*$36.33*
465-474 W	Per Light	*$8.42*	$0.00	*$8.42*	*$28.53*	*$36.95*
475-484 W	Per Light	*$8.60*	$0.00	*$8.60*	*$28.98*	*$37.58*

(Continued on Sheet No. D-90.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

Third Revised Sheet No. D-90.20
Cancels Second Revised Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after January 20, 2023:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.35	$0.00	$0.35	$5.67	$6.02
25-34 W	Per Light	$0.53	$0.00	$0.53	$6.11	$6.64
35-44 W	Per Light	$0.71	$0.00	$0.71	$6.55	$7.26
45-54 W	Per Light	$0.89	$0.00	$0.89	$7.00	$7.89
55-64 W	Per Light	$1.07	$0.00	$1.07	$7.44	$8.51
65-74 W	Per Light	$1.25	$0.00	$1.25	$7.88	$9.13
75-84 W	Per Light	$1.43	$0.00	$1.43	$8.32	$9.75
85-94 W	Per Light	$1.61	$0.00	$1.61	$8.76	$10.37
95-104 W	Per Light	$1.78	$0.00	$1.78	$9.20	$10.98
105-114 W	Per Light	$1.96	$0.00	$1.96	$9.64	$11.60
115-124 W	Per Light	$2.14	$0.00	$2.14	$10.08	$12.22
125-134 W	Per Light	$2.32	$0.00	$2.32	$10.53	$12.85
135-144 W	Per Light	$2.50	$0.00	$2.50	$10.97	$13.47
145-154 W	Per Light	$2.68	$0.00	$2.68	$11.41	$14.09
155-164 W	Per Light	$2.86	$0.00	$2.86	$11.85	$14.71
165-174 W	Per Light	$3.04	$0.00	$3.04	$12.29	$15.33
175-184 W	Per Light	$3.22	$0.00	$3.22	$12.73	$15.95
185-194 W	Per Light	$3.40	$0.00	$3.40	$13.17	$16.57
195-204 W	Per Light	$3.58	$0.00	$3.58	$13.62	$17.20
205-214 W	Per Light	$3.76	$0.00	$3.76	$14.06	$17.82
215-224 W	Per Light	$3.94	$0.00	$3.94	$14.50	$18.44
225-234 W	Per Light	$4.12	$0.00	$4.12	$14.94	$19.06
235-244 W	Per Light	$4.30	$0.00	$4.30	$15.38	$19.68
245-254 W	Per Light	$4.48	$0.00	$4.48	$15.82	$20.30
255-264 W	Per Light	$4.65	$0.00	$4.65	$16.26	$20.91
265-274 W	Per Light	$4.83	$0.00	$4.83	$16.71	$21.54
275-284 W	Per Light	$5.01	$0.00	$5.01	$17.15	$22.16
285-294 W	Per Light	$5.19	$0.00	$5.19	$17.59	$22.78
295-304 W	Per Light	$5.37	$0.00	$5.37	$18.03	$23.40
305-314 W	Per Light	$5.55	$0.00	$5.55	$18.47	$24.02
315-324 W	Per Light	$5.73	$0.00	$5.73	$18.91	$24.64
325-334 W	Per Light	$5.91	$0.00	$5.91	$19.35	$25.26
335-344 W	Per Light	$6.09	$0.00	$6.09	$19.80	$25.89
345-354 W	Per Light	$6.27	$0.00	$6.27	$20.24	$26.51
355-364 W	Per Light	$6.45	$0.00	$6.45	$20.68	$27.13
365-374 W	Per Light	$6.63	$0.00	$6.63	$21.12	$27.75
375-384 W	Per Light	$6.81	$0.00	$6.81	$21.56	$28.37
385-394 W	Per Light	$6.99	$0.00	$6.99	$22.00	$28.99
395-404 W	Per Light	$7.17	$0.00	$7.17	$22.44	$29.61
405-414 W	Per Light	$7.35	$0.00	$7.35	$22.89	$30.24
415-424 W	Per Light	$7.52	$0.00	$7.52	$23.33	$30.85
425-434 W	Per Light	$7.70	$0.00	$7.70	$23.77	$31.47
435-444 W	Per Light	$7.88	$0.00	$7.88	$24.21	$32.09
445-454 W	Per Light	$8.06	$0.00	$8.06	$24.65	$32.71
455-464 W	Per Light	$8.24	$0.00	$8.24	$25.09	$33.33
465-474 W	Per Light	$8.42	$0.00	$8.42	$25.53	$33.95
475-484 W	Per Light	$8.60	$0.00	$8.60	$25.98	$34.58

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

(Continued on Sheet No. D-91.00)

Issued December 19, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for bills rendered on and after the Company's January 2024 Billing Month

Issued under authority of the Michigan Public Service Commission dated December 17, 2020 in Case No. U-20889

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.20)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms, Surcharges, Power Supply Cost Recovery (PSCR) Factor and Securitization Charges:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00, Surcharges shown on Nos. D-2.00 through D-5.00, PSCR Factor shown on Sheet No. D-6.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

(Continued on Sheet No. D-92.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-91.00)

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the capacity requirements in watts of the lamp(s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

Nature of Service:

Company-Owned Option

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:

Company-Owned Option

Following execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company. *A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-94.00)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $(*6.04*) per month

(Continued on Sheet No. D-94.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Second Revised Sheet No. D-94.10
Cancels First Revised Sheet No. D-94.10

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.00)

Monthly Rate (Contd)

Transitional Unmetered Lighting Rate GU-LED Charges, effective *March 18, 2022* through June 30, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$8.32	$8.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$8.98	$9.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$9.64	$10.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$10.31	$11.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$10.97	$12.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$11.63	$12.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$12.30	$13.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$12.96	$14.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$13.62	$15.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$14.28	$16.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$14.95	$17.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$15.61	$17.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$16.27	$18.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$16.94	$19.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$17.60	$20.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$18.26	$21.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$18.93	$22.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$19.59	$22.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$20.25	$23.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$20.92	$24.51

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$5.32	$5.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$5.98	$6.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$6.64	$7.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$7.31	$8.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$7.97	$9.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$8.63	$9.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$9.30	$10.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$9.96	$11.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$10.62	$12.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$11.28	$13.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$11.95	$14.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$12.61	$14.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$13.27	$15.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$13.94	$16.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$14.60	$17.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$15.26	$18.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$15.93	$19.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$16.59	$19.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$17.25	$20.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$17.92	$21.51

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-94.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *January 20, 2023*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.35*	$0.00	*$0.35*	*$8.67*	*$9.02*
25-34 W	Per Light	*$0.53*	$0.00	*$0.53*	*$9.11*	*$9.64*
35-44 W	Per Light	*$0.71*	$0.00	*$0.71*	*$9.55*	*$10.26*
45-54 W	Per Light	*$0.89*	$0.00	*$0.89*	*$10.00*	*$10.89*
55-64 W	Per Light	*$1.07*	$0.00	*$1.07*	*$10.44*	*$11.51*
65-74 W	Per Light	*$1.25*	$0.00	*$1.25*	*$10.88*	*$12.13*
75-84 W	Per Light	*$1.43*	$0.00	*$1.43*	*$11.32*	*$12.75*
85-94 W	Per Light	*$1.61*	$0.00	*$1.61*	*$11.76*	*$13.37*
95-104 W	Per Light	*$1.78*	$0.00	*$1.78*	*$12.20*	*$13.98*
105-114 W	Per Light	*$1.96*	$0.00	*$1.96*	*$12.64*	*$14.60*
115-124 W	Per Light	*$2.14*	$0.00	*$2.14*	*$13.08*	*$15.22*
125-134 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.53*	*$15.85*
135-144 W	Per Light	*$2.50*	$0.00	*$2.50*	*$13.97*	*$16.47*
145-154 W	Per Light	*$2.68*	$0.00	*$2.68*	*$14.41*	*$17.09*
155-164 W	Per Light	*$2.86*	$0.00	*$2.86*	*$14.85*	*$17.71*
165-174 W	Per Light	*$3.04*	$0.00	*$3.04*	*$15.29*	*$18.33*
175-184 W	Per Light	*$3.22*	$0.00	*$3.22*	*$15.73*	*$18.95*
185-194 W	Per Light	*$3.40*	$0.00	*$3.40*	*$16.17*	*$19.57*
195-204 W	Per Light	*$3.58*	$0.00	*$3.58*	*$16.62*	*$20.20*
205-214 W	Per Light	*$3.76*	$0.00	*$3.76*	*$17.06*	*$20.82*
215-224 W	Per Light	*$3.94*	$0.00	*$3.94*	*$17.50*	*$21.44*
225-234 W	Per Light	*$4.12*	$0.00	*$4.12*	*$17.94*	*$22.06*
235-244 W	Per Light	*$4.30*	$0.00	*$4.30*	*$18.38*	*$22.68*
245-254 W	Per Light	*$4.48*	$0.00	*$4.48*	*$18.82*	*$23.30*
255-264 W	Per Light	*$4.65*	$0.00	*$4.65*	*$19.26*	*$23.91*
265-274 W	Per Light	*$4.83*	$0.00	*$4.83*	*$19.71*	*$24.54*
275-284 W	Per Light	*$5.01*	$0.00	*$5.01*	*$20.15*	*$25.16*
285-294 W	Per Light	*$5.19*	$0.00	*$5.19*	*$20.59*	*$25.78*
295-304 W	Per Light	*$5.37*	$0.00	*$5.37*	*$21.03*	*$26.40*
305-314 W	Per Light	*$5.55*	$0.00	*$5.55*	*$21.47*	*$27.02*
315-324 W	Per Light	*$5.73*	$0.00	*$5.73*	*$21.91*	*$27.64*
325-334 W	Per Light	*$5.91*	$0.00	*$5.91*	*$22.35*	*$28.26*
335-344 W	Per Light	*$6.09*	$0.00	*$6.09*	*$22.80*	*$28.89*
345-354 W	Per Light	*$6.27*	$0.00	*$6.27*	*$23.24*	*$29.51*
355-364 W	Per Light	*$6.45*	$0.00	*$6.45*	*$23.68*	*$30.13*
365-374 W	Per Light	*$6.63*	$0.00	*$6.63*	*$24.12*	*$30.75*
375-384 W	Per Light	*$6.81*	$0.00	*$6.81*	*$24.56*	*$31.37*
385-394 W	Per Light	*$6.99*	$0.00	*$6.99*	*$25.00*	*$31.99*
395-404 W	Per Light	*$7.17*	$0.00	*$7.17*	*$25.44*	*$32.61*
405-414 W	Per Light	*$7.35*	$0.00	*$7.35*	*$25.89*	*$33.24*
415-424 W	Per Light	*$7.52*	$0.00	*$7.52*	*$26.33*	*$33.85*
425-434 W	Per Light	*$7.70*	$0.00	*$7.70*	*$26.77*	*$34.47*
435-444 W	Per Light	*$7.88*	$0.00	*$7.88*	*$27.21*	*$35.09*
445-454 W	Per Light	*$8.06*	$0.00	*$8.06*	*$27.65*	*$35.71*
455-464 W	Per Light	*$8.24*	$0.00	*$8.24*	*$28.09*	*$36.33*
465-474 W	Per Light	*$8.42*	$0.00	*$8.42*	*$28.53*	*$36.95*
475-484 W	Per Light	*$8.60*	$0.00	*$8.60*	*$28.98*	*$37.58*

(Continued on Sheet No. D-94.30)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after January 20, 2023:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.35	$0.00	$0.35	$5.67	$6.02
25-34 W	Per Light	$0.53	$0.00	$0.53	$6.11	$6.64
35-44 W	Per Light	$0.71	$0.00	$0.71	$6.55	$7.26
45-54 W	Per Light	$0.89	$0.00	$0.89	$7.00	$7.89
55-64 W	Per Light	$1.07	$0.00	$1.07	$7.44	$8.51
65-74 W	Per Light	$1.25	$0.00	$1.25	$7.88	$9.13
75-84 W	Per Light	$1.43	$0.00	$1.43	$8.32	$9.75
85-94 W	Per Light	$1.61	$0.00	$1.61	$8.76	$10.37
95-104 W	Per Light	$1.78	$0.00	$1.78	$9.20	$10.98
105-114 W	Per Light	$1.96	$0.00	$1.96	$9.64	$11.60
115-124 W	Per Light	$2.14	$0.00	$2.14	$10.08	$12.22
125-134 W	Per Light	$2.32	$0.00	$2.32	$10.53	$12.85
135-144 W	Per Light	$2.50	$0.00	$2.50	$10.97	$13.47
145-154 W	Per Light	$2.68	$0.00	$2.68	$11.41	$14.09
155-164 W	Per Light	$2.86	$0.00	$2.86	$11.85	$14.71
165-174 W	Per Light	$3.04	$0.00	$3.04	$12.29	$15.33
175-184 W	Per Light	$3.22	$0.00	$3.22	$12.73	$15.95
185-194 W	Per Light	$3.40	$0.00	$3.40	$13.17	$16.57
195-204 W	Per Light	$3.58	$0.00	$3.58	$13.62	$17.20
205-214 W	Per Light	$3.76	$0.00	$3.76	$14.06	$17.82
215-224 W	Per Light	$3.94	$0.00	$3.94	$14.50	$18.44
225-234 W	Per Light	$4.12	$0.00	$4.12	$14.94	$19.06
235-244 W	Per Light	$4.30	$0.00	$4.30	$15.38	$19.68
245-254 W	Per Light	$4.48	$0.00	$4.48	$15.82	$20.30
255-264 W	Per Light	$4.65	$0.00	$4.65	$16.26	$20.91
265-274 W	Per Light	$4.83	$0.00	$4.83	$16.71	$21.54
275-284 W	Per Light	$5.01	$0.00	$5.01	$17.15	$22.16
285-294 W	Per Light	$5.19	$0.00	$5.19	$17.59	$22.78
295-304 W	Per Light	$5.37	$0.00	$5.37	$18.03	$23.40
305-314 W	Per Light	$5.55	$0.00	$5.55	$18.47	$24.02
315-324 W	Per Light	$5.73	$0.00	$5.73	$18.91	$24.64
325-334 W	Per Light	$5.91	$0.00	$5.91	$19.35	$25.26
335-344 W	Per Light	$6.09	$0.00	$6.09	$19.80	$25.89
345-354 W	Per Light	$6.27	$0.00	$6.27	$20.24	$26.51
355-364 W	Per Light	$6.45	$0.00	$6.45	$20.68	$27.13
365-374 W	Per Light	$6.63	$0.00	$6.63	$21.12	$27.75
375-384 W	Per Light	$6.81	$0.00	$6.81	$21.56	$28.37
385-394 W	Per Light	$6.99	$0.00	$6.99	$22.00	$28.99
395-404 W	Per Light	$7.17	$0.00	$7.17	$22.44	$29.61
405-414 W	Per Light	$7.35	$0.00	$7.35	$22.89	$30.24
415-424 W	Per Light	$7.52	$0.00	$7.52	$23.33	$30.85
425-434 W	Per Light	$7.70	$0.00	$7.70	$23.77	$31.47
435-444 W	Per Light	$7.88	$0.00	$7.88	$24.21	$32.09
445-454 W	Per Light	$8.06	$0.00	$8.06	$24.65	$32.71
455-464 W	Per Light	$8.24	$0.00	$8.24	$25.09	$33.33
465-474 W	Per Light	$8.42	$0.00	$8.42	$25.53	$33.95
475-484 W	Per Light	$8.60	$0.00	$8.60	$25.98	$34.58

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

(Continued on Sheet No. D-95.00)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.30)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered LED Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered LED Lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.063654	$0.013565	$0.077219	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$0.022612	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10.*

(Continued on Sheet No. D-97.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-96.00)

Monthly Rate: (Contd)

Determination of kWh:

The monthly charge shall be the per kWh total of the Power Supply and Delivery Charges as shown above based on the capacity requirements in Kilowatts of the lamp(s), associated ballast(s) and control equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption. At the Company's option, such service may be metered and the metered kWh used as the basis for billing. The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

For dusk to midnight service for energy-only unmetered lighting, the monthly charge per kWh shall be 130% of the sum of the Secondary Energy Charge and Distribution Charge per kWh for secondary service. The annual kWh shall be based on the actual burning hours. The monthly kWh for billing shall be the annual kWh adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be 50% of the total kWh so calculated. The kWh for continuous, nonintermittent devices shall be 100% of the total kWh so calculated. No reduction in kWh shall be made for devices not operated 24 hours per day, or not operated every day.

The kWh of devices used for the control of school traffic, and operated not more than six hours per day during the school year only, shall be 10% of the continuous or cyclical kWh calculated.

The kWh for CATV Power Supply Units shall be 50% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The kWh for Wireless Access and Security Camera Power Supply Units shall be 100% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The Company may, at its option, install test meters for the purpose of determining the monthly kWh usage to be used for billing purposes.

(Continued on Sheet No. D-98.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-97.00)

Monthly Rate (Contd)

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, plus any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

Case No: U-21393
Utility: Consumers Energy Company
Date: February 22, 2024
Exhibit 13 of 13: Designees for Copies of Contracts

The Company designates a primary and secondary contact to assist with requested customer contract review. The designated contacts are:

Primary Designee:

Name: Sarah Jorgensen
Email: sarah.jorgensen@cmsenergy.com
Office Phone: (248) 433-5986517

Secondary Designee:

Name: Kenneth Selander
Email: Kenneth.Selander@cmsenergy.com
Office Phone: (517) 740-1372

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 27

2028/2029 Consumers Capacity Demonstration

February 24, 2025

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

Re: MPSC Case No. U-21775 – In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029**. A confidential version of this filing is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2025.02.24 09:28:41 -05'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.	))))))	Case No. U-21775

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

AFFIDAVIT OF SRIKANTH MADDIPATI

Srikanth Maddipati, being duly sworn, states that the following information and attached exhibits are true and accurate to the best of my reasonable knowledge and belief, regarding Consumers Energy Company's ("Consumers Energy" or the "Company") satisfaction of its Michigan capacity demonstration requirements:

1. I am the Vice President of Electric Supply for Consumers Energy. My responsibilities include, in part, overall responsibility for the Company's long-term and short-term electric supply planning, investments, and strategy. I received a Bachelor of Science Degree in Computer Engineering from the University of Michigan in 2004 and, concurrently, completed my Master of Science Degree in Engineering with a specialization in Signal Processing. I received a Master of Business Administration Degree ("MBA") from the Ross School of Business at the University of Michigan in 2008, where I focused on Finance and Accounting.

2. Consumers Energy is a public utility engaged in the generation, purchase, distribution, and sale of electric energy to approximately 1.9 million retail electric customers in the lower peninsula of the state of Michigan. Consumers Energy remains committed to planning

for and providing an adequate electric supply to meet the needs of Michigan homes and businesses, with reliable, flexible, and cost-effective energy.

3. The information provided in this Affidavit is based on my first-hand knowledge of the Company's long-term and short-term electric supply planning, investments, and strategy. Pursuant to Section 6w of 2016 PA 341, and as required by the Michigan Public Service Commission's ("MPSC" or the "Commission") August 22, 2024 Order in Case No. U-21393, this Affidavit is a demonstration to the Commission that the Company has sufficient electric capacity arrangements for Planning Year[1] ("PY") 2028/2029. The remainder of this Affidavit discusses the Planning Reserve Margin Requirement ("PRMR"), peak demand outlook, and the capacity resources planned to fulfill customer need.

4. Consumers Energy remains dedicated to meeting the needs of its full-service electric customers over the four-year planning period while maintaining adequate reserve margins, as detailed in this filing, with:

- Demand Response ("DR") consistent with the Company's 2021 Integrated Resource Plan ("IRP") Proposed Course of Action ("PCA") as approved in MPSC Case No. U-21090 ("IRP Settlement"). As DR programs evolve, there may be shifting of DR levels among the different programs;
- Offered capacity generated from existing resources in the applicable Michigan Zone;
- Contracted amounts of Power Purchase Agreements ("PPA") in accordance with the terms of the applicable agreements; and
- Renewable capacity from existing and new resources, as identified in this filing consistent with the Company's Renewable Energy Plan and IRP PCA.

[1] Planning Year, as defined by the Midcontinent Independent System Operator, Inc. ("MISO"), is the 12-month period commencing on June 1 of each year and concluding on May 31 of the following year.

5. Consumers Energy plans to sufficiently serve its full-service customers for the next four years and beyond. The Company's plans are outlined in the following paragraphs, covering PYs 2025/2026 through 2028/2029, and address each of the required capacity areas:

- Exhibit 1 — Utility Bundled Service Peak Demand for Michigan Midcontinent Independent System Operator, Inc. ("MISO") LRZ 7;
- Exhibit 2 — Planning Reserve Margin Requirements and Planning Resources to be Acquired (Zonal Resource Credit ("ZRC"));
- Exhibit 3 — Demand Response—Capacity Resources;
- Exhibit 4 — Company-Owned Electric Generation Resources (Confidential);
- Exhibit 5 — New or Upgraded Generation Owned;
- Exhibit 6 — Generation Resources Under PPA or Other Capacity Contract (Confidential); and
- Exhibit 7 — New or Upgraded Purchased Power.

6. MISO Module E Reports for Planning Year 2024/25

Reports from the MISO Module E Capacity Tracking tool demonstrating the unforced[2] capacity ("UCAP") confirmed by the Company for PY 2024/25 are provided as Exhibits 8 through 11.

- Exhibit 8 — Existing Owned Generation (Confidential);
- Exhibit 9 — MISO Registered Demand Response Programs (Confidential);
- Exhibit 10 — Existing Purchased Power Agreements (Confidential); and
- Exhibit 11 — Existing Transactions (Confidential).

7. Additional Exhibits

- Exhibit 12 – Relevant Tariffs; and

[2] MISO's evaluation of Loss of Load Expectation for PY 2024/25 utilized net demonstrated capacity less the three-year Equivalent Forced Outage Rate on demand, or "EFORd." The resulting capacity value is commonly referred to as "unforced."

- Exhibit 13 – Company Contact List.

In lieu of filing a copy of the customer supply contracts with this capacity demonstration, the Company agrees to make available the customer supply contracts relevant to the Commercial and Industrial Demand Response ("DR Contracts") Program and Interruptible Service ("Rate GI") Provision for the Commission Staff's ("Staff") review upon request, without Staff retaining a copy. Exhibit 13 contains the contact information of the persons designated to make available the customer supply contracts and copies of any of the Company's PPAs for review by Staff.

8. PRMR

The capacity Planning Reserve Margin ("PRM") target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to ensure sufficient capacity exists to provide adequate electric supply in each seasonal period within a PY. The Company relies upon MISO to determine the appropriate capacity PRM that Consumers Energy should maintain. For PY 2025, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. MISO's PY 2025-2026 Loss of Load Expectation Study Report was published on November 22, 2024. Upon determining the amount of generation resources necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

MISO's seasonal construct was accepted by the Federal Energy Regulatory Commission in September 2022, which introduced seasonal requirements to the Planning Resource Auction ("PRA"). As a result, MISO's LOLE study sets the system-wide capacity Planning Reserve Margin Unforced Capacity ("PRM UCAP") and the zonal Local Reliability Requirements

("LRR") for each season for the upcoming 2025/2026 PY. Under the MISO seasonal construct, the annual planning year is divided into four distinct seasons between June 1, 2025, and May 31, 2026, and for subsequent planning years moving forward. The seasons are Summer from June 1 – August 31, Fall from September 1 – November 30, Winter from December 1 – February 28, and Spring from March 1 - May 31.

On November 22, 2024, MISO determined seasonal PRM UCAP planning reserve margin targets for PY 2025/2026 of 7.9% for Summer, 14.9% for Fall, 18.4% for Winter, and 25.3% for Spring. The Company is filing this capacity demonstration for PY 2028/2029 using the prompt year seasonal capacity obligations and resource credit assumptions based on each individual season. The exhibits will be labeled by season (Summer, Fall, Winter, Spring) respectively for each season. The Company also forecasted load requirements for the 2028/2029 PY as it has done for prior capacity demonstrations. The Company will plan to meet the Company's PRMR and thus maintain resources to meet full-service customer capacity needs throughout the PY, including during peak load periods.

9. Peak Demand

The Company's historical and forecasted peak demands are shown in Exhibit 1. The values provided in Exhibit 1 are not weather-normalized. The peak demands shown in Exhibit 1 include supplying demand associated with Bundled (full-service) customers, Choice customers through Retail Open Access, and the summation of Bundled and Choice customers denoted as Service Territory peak demand.

Existing DR or Energy Waste Reduction ("EWR") resources netted against load are detailed in the section below and can be found in Exhibit 2, line 2.

The Company must plan for capacity during periods when MISO experiences its peak demand. The Company's forecast of peak bundled demand is adjusted to align with MISO's peak demand for each season, which requires application of a diversity factor as shown in Exhibit 2, lines 4 and 5. The Company's forecast of peak bundled demand is also adjusted to include transmission losses, which requires application of a transmission loss factor as shown in Exhibit 2, line 6.

Consumers Energy plans to draw on a diverse portfolio of resources to meet its annual PRMR obligation. Those resources include utility-owned generation, long-term supply contracts, EWR, and DR resources.

10. Existing Generation — Owned

Consumers Energy currently owns, operates, and manages resources all located within Michigan and within MISO Zone 7 and plans to offer the LSE capacity from these resources in the applicable Michigan Zone throughout the four-year planning period. A summary of the Company's forecast for its owned resources — including resource type, installed capacity, and Installed Seasonal Accreditation Capacity ("ISAC") — is provided in Exhibit 2 (by category) and Exhibit 4 (by unit).

11. Existing DR or EWR Resources (Not Netted Against Load)

Consumers Energy offers a suite of Demand-Side Management programs available for residential, commercial, and industrial customer classes to deliver and manage significant peak load reductions. Existing programs offered by the Company that are not netted against load and can be offered into MISO as a capacity resource include:

- Air Conditioning Peak Cycling ("ACPC") Program;
- Commercial & Industrial Demand Response (DR Contracts);

- Rate GI/GI 2 (DR Rate GI Reduce By/DR Rate GI Reduce to); and
- Smart Thermostat Program.

Existing Demand-Side Management programs not netted against load result in total load modifying resources as shown in Exhibit 2, line 18. Exhibit 3 provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio. Exhibit 9 summarizes these DR programs with data from the MISO Module E Report for PY 2024/2025.

Transmission losses and the PRM (on a UCAP basis) were applied per MISO standard practice for registered DR capacity, as detailed in (BPM-011-r29).[3]

12. Existing DR or EWR Resources (Netted Against Load)

Existing DR and EWR programs netted against load include (Exhibit 2, line 2):

- Dynamic Peak Pricing;
- Residential Summer on-peak rate RSP;
- EWR; and
- Internal Demand Response Program Conservation Voltage Reduction.

Growth in these Demand-Side Management programs (in combination with those not netted against load) is consistent with the IRP Settlement. The applicable tariff sheets are included in Exhibit 12.

13. New or Upgraded Utility-Owned Generation

New or upgraded utility-owned generation planned for 2025 through 2028 includes new renewable resources in accordance with the Company's Renewable Energy Plan and the IRP

[3] https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

Settlement. Details for these resources including planned in-service dates, expected regulatory approval dates, and expected dates for a MISO Generator Interconnection Agreement can be found in Exhibit 5. The addition of these resources in the Company's capacity planning projections are reflected in the annual values shown in Exhibit 2 (in combination with existing units) and Exhibit 4 (by individual unit) and are based on the construction and Commercial Operation Dates ("COD") identified in Exhibit 5.

14. New DR or EWR Resources (Not Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would not be netted against load.

15. New DR or EWR Resources (Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would be netted against load.

16. Existing Generation Capacity Contracts

The Company has PPAs in place for the purchase of energy, capacity, and renewable energy credits. The majority of Consumers Energy's PPAs are sourced within Michigan and within MISO Zone 7—the exception being the Heritage Garden Wind Farm, which is located in MISO Zone 2. Exhibit 6 presents a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations. The Company has several contracts in place with facilities that meet, or are expected to meet, the requirements of Qualifying Facilities ("QFs"), in accordance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"), that will terminate from 2023 to 2027. Page 2 of Exhibit 6 details the QFs that have expiring contracts which are expected to be replaced with new PURPA contracts upon expiration. Exhibit 6 presents

a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations.

17. New or Upgraded Purchased Power

The Company's New or Upgraded Purchased Power resources are presented in Exhibit 7. There are three types of resources detailed in this exhibit. First, the Company has forecasted existing PURPA-based contracts will be replaced with new PURPA-based agreements. Obligations for these contracts are projected to remain throughout the four-year planning period. The ZRCs associated with new PURPA-based contracts are identified in Exhibit 6, line 45. Second, the Company has contracted PPAs for new solar PURPA capacity per the Settlement Agreement in Case No. U-20615 ("PURPA Settlement"). Exhibits 6 and 7 present a forecast of the PURPA Settlement solar projects expected to achieve commercial operation through PY 2028. Because interconnection agreements and full construction schedules for many of these resources are not yet finalized, the expected construction dates presented in Exhibit 7 are subject to change. Finally, Exhibit 6, line 2, and Exhibit 7, line 1, show the details for the 150 MW of solar projects with a COD in June 2028 that the Company is actively procuring through its annual IRP solicitations.

Consumers Energy plans to maintain the contracted amounts of these PPAs as shown in the attached exhibits and in accordance with the terms of the applicable agreements throughout the four-year planning period.

18. Forward ZRC Contracts

As shown on Exhibit 6, line 1, the Company has a three-year contract with Midland Cogeneration Venture Limited Partnership to provide 100 MW for each of the PY's 2025, 2026,

and 2027. Additionally, the Company has contracted for capacity through the 2024 Reverse Capacity Auction, for PY's 2025 and 2026. This is shown in Exhibit 6, line 3.

19. Planning Resource Auction Purchases

The Company projects PRA purchases for the Winter of PY 2028, as well as the Fall of PY's 2025, 2026, and 2028 as shown in the Winter and Fall Exhibits 2, line 34.

If sworn as a witness, I would testify as set forth above.

Srikanth Maddipati

Subscribed and sworn to before me this 24th day of February 2025.

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

SUMMER
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 1
Page: 1 of 1

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Summer Season

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)
		PY 2024-25	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	8,458	8,458	8,505	8,680	8,905
2	Choice, Coincident to Service Territory	449	384	461	457	457
3	Bundled (line 1 - line 2)	8,009	8,074	8,044	8,223	8,449
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	8,147	8,168	8,214	8,382	8,600
5	Choice, Coincident to Service Territory	433	370	446	441	441
6	Bundled (line 4 - line 5)	7,714	7,797	7,768	7,941	8,159

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 2
Page: 1 of 1

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Summer Season

Line	(a)	(b) PY 2025-26	(c) PY 2026-27	(d) PY 2027-28	(e) PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	8,074	8,044	8,223	8,449
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	1,023	1,144	1,157	1,185
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,051	6,900	7,066	7,263
4	Load Diversity Factor coincident to MISO, %.	96.57%	96.57%	96.57%	96.57%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,809	6,663	6,823	7,014
6	Transmission Losses, %	3.30%	3.30%	3.30%	3.30%
7	Planning Reserve Margin % UCAP Basis	7.90%	9.40%	9.60%	9.50%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,590	7,530	7,725	7,934
9	Company Owned, In-State, Non-Intermittent, ZRC	4,321	4,163	4,163	4,166
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	178	527	716	1,201
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	12	14	16	16
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,528	4,722	4,913	5,401
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	651	684	691	691
19	PPA, In-State, Non-Intermittent, ZRC	1,665	1,585	1,571	1,407
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	30	28	24	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	393	658	903	978
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	23	23	23	23
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	22	22
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	240	240	240	240
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,351	2,539	2,782	2,694
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	-
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,625	8,015	8,387	8,785
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	35	484	662	851

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 3
Page: 1 of 1

Exhibit 3 - Demand Response - Capacity Resources - Summer Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	35	4	39
2		Rate EIP	-	-	-
3		DR CONTRACTS	240	28	268
4		DR RATE GI REDUCE BY	16	2	18
5		DR RATE GI REDUCE TO	249	29	278
6		Smart Thermostat Program (STP)	44	5	49
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				651.4
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
10		Rate EIP	10	1	11
11		DR CONTRACTS	220	29	249
12		DR RATE GI REDUCE BY	16	2	19
13		DR RATE GI REDUCE TO	249	32	282
14		Smart Thermostat Program (STP)	75	10	85
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				684.3
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
18		Rate EIP	15	2	17
19		DR CONTRACTS	220	29	249
20		DR RATE GI REDUCE BY	16	2	19
21		DR RATE GI REDUCE TO	249	33	282
22		Smart Thermostat Program (STP)	75	10	85
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				691.2
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
26		Rate EIP	15	2	17
27		DR CONTRACTS	220	29	249
28		DR RATE GI REDUCE BY	16	2	19
29		DR RATE GI REDUCE TO	249	33	282
30		Smart Thermostat Program (STP)	75	10	85
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				690.6

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Summer Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	81.90%	18	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE, therefore they will not be obtaining a MISO queue cycle.
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Summer Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	30.00%	14	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Storage	100	5.00%	95	May 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	82.19%	20	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

FALL
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 1
Page: 1 of 1

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Fall Season

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)
		PY 2024-25	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	7,322	7,419	7,605	7,840	7,858
2	Choice, Coincident to Service Territory	531	397	499	493	485
3	Bundled (line 1 - line 2)	6,791	7,022	7,106	7,346	7,373
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	7,224	7,318	7,501	7,733	7,751
5	Choice, Coincident to Service Territory	524	391	492	487	479
6	Bundled (line 4 - line 5)	6,700	6,927	7,009	7,247	7,272

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 2
Page: 1 of 1

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Fall Season

Line	(a)	(b) PY 2025-26	(c) PY 2026-27	(d) PY 2027-28	(e) PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,022	7,106	7,346	7,373
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	842	951	969	1,003
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	6,180	6,155	6,378	6,370
4	Load Diversity Factor coincident to MISO, %.	98.64%	98.64%	98.64%	98.64%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,096	6,071	6,291	6,284
6	Transmission Losses, %	4.50%	4.50%	4.50%	4.50%
7	Planning Reserve Margin % UCAP Basis	14.90%	15.30%	15.90%	15.70%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,320	7,315	7,620	7,597
9	Company Owned, In-State, Non-Intermittent, ZRC	3,852	3,753	3,990	3,396
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	18	18	18	18
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	209	558	747	1,230
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	13	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,089	4,341	4,770	4,659
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	381	338	346	345
19	PPA, In-State, Non-Intermittent, ZRC	1,649	1,562	1,545	1,388
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	31	29	25	25
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	397	662	907	982
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	8	8	8	8
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	22	22
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	148	148	148	148
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,233	2,415	2,656	2,573
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	105	70	-	-
34	Planned Capacity Purchases, ZRC	512	151	-	20
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,320	7,315	7,772	7,597
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	(0)	(0)	152	(0)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 3
Page: 1 of 1

Exhibit 3 - Demand Response - Capacity Resources - Fall Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	46	9	55
4		DR RATE GI REDUCE BY	16	3	20
5		DR RATE GI REDUCE TO	255	51	306
6					-
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				381.3
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
10		Rate EIP	10	2	12
11		DR CONTRACTS	-	-	-
12		DR RATE GI REDUCE BY	15	3	18
13		DR RATE GI REDUCE TO	255	52	308
14					-
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				337.8
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
18		Rate EIP	15	3	18
19		DR CONTRACTS	-	-	-
20		DR RATE GI REDUCE BY	15	3	18
21		DR RATE GI REDUCE TO	255	54	309
22					-
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				345.7
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
26		Rate EIP	15	3	18
27		DR CONTRACTS	-	-	-
28		DR RATE GI REDUCE BY	15	3	18
29		DR RATE GI REDUCE TO	255	53	309
30					-
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				345.1

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Fall Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/30/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	84.40%	16	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE therefore they will not be obtaining a MISO queue cycle
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Fall Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	50.00%	10	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300.0	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Solar	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	94.65%	6	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

WINTER
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 1
Page: 1 of 1

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Winter Season

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)
		PY 2024-25	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,286	6,407	6,608	6,695	6,788
2	Choice, Coincident to Service Territory	296	386	407	385	397
3	Bundled (line 1 - line 2)	5,989	6,021	6,200	6,310	6,391
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,200	6,327	6,525	6,611	6,703
5	Choice, Coincident to Service Territory	292	381	402	381	392
6	Bundled (line 4 - line 5)	5,908	5,946	6,123	6,231	6,311

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 2
Page: 1 of 1

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Winter Season

Line	(a)	(b) PY 2025-26	(c) PY 2026-27	(d) PY 2027-28	(e) PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,021	6,200	6,310	6,391
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	788	879	895	889
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,234	5,321	5,414	5,502
4	Load Diversity Factor coincident to MISO, %.	98.75%	98.75%	98.75%	98.75%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,168	5,255	5,346	5,433
6	Transmission Losses, %	3.00%	3.00%	3.00%	3.00%
7	Planning Reserve Margin % UCAP Basis	18.40%	27.00%	26.80%	26.50%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,303	6,873	6,982	7,079
9	Company Owned, In-State, Non-Intermittent, ZRC	4,384	4,134	4,320	4,135
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	224	259	342	442
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	13	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,636	4,423	4,695	4,610
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	389	373	379	378
19	PPA, In-State, Non-Intermittent, ZRC	1,603	1,603	1,548	1,415
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	27	25	22	22
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	282	480	590	592
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	5	5	4	4
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	5	23	23
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	6	6	6	6
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,923	2,123	2,192	2,061
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	30
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,042	6,989	7,266	7,079
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	740	116	283	(0)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 3
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Exhibit 3 - Demand Response - Capacity Resources - Winter Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	43	9	52
4		DR RATE GI REDUCE BY	16	4	20
5		DR RATE GI REDUCE TO	259	57	316
6					-
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				388.7
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
10		Rate EIP	10	3	13
11		DR CONTRACTS	-	-	-
12		DR RATE GI REDUCE BY	15	5	20
13		DR RATE GI REDUCE TO	259	80	339
14					-
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				372.5
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
18		Rate EIP	15	5	20
19		DR CONTRACTS	-	-	-
20		DR RATE GI REDUCE BY	15	5	20
21		DR RATE GI REDUCE TO	259	79	339
22					-
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				378.5
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
26		Rate EIP	15	5	20
27		DR CONTRACTS	-	-	-
28		DR RATE GI REDUCE BY	15	5	20
29		DR RATE GI REDUCE TO	259	79	338
30					-
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				377.6

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	95.00%	13	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	95.00%	8	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	95.00%	8	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	95.00%	4	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	95.00%	15	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	95.00%	7	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	95.00%	15	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	95.00%	7	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	95.00%	11	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	95.00%	6	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	46.90%	53	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE therefore they will not be obtaining a MISO queue cycle
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	95.00%	8	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	95.00%	1	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	95.00%	15	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	95.00%	8	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	95.00%	6	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	95.00%	0	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	95.00%	0	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	95.00%	5	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	95.00%	1	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	95.00%	0	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Storage	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	99.12%	1	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

SPRING
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 1
Page: 1 of 1

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Spring Season

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,428	6,800	6,886	6,977	7,001
2	Choice, Coincident to Service Territory	362	582	444	428	420
3	Bundled (line 1 - line 2)	6,066	6,218	6,441	6,549	6,581
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,342	6,708	6,793	6,882	6,906
5	Choice, Coincident to Service Territory	357	574	438	422	415
6	Bundled (line 4 - line 5)	5,984	6,134	6,354	6,460	6,492

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 2
Page: 1 of 1

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Spring Season

Line	(a)	(b) PY 2025-26	(c) PY 2026-27	(d) PY 2027-28	(e) PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,218	6,441	6,549	6,581
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	808	843	862	861
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,410	5,599	5,686	5,720
4	Load Diversity Factor coincident to MISO, %.	98.65%	98.65%	98.65%	98.65%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,337	5,523	5,609	5,643
6	Transmission Losses, %	3.20%	3.20%	3.20%	3.20%
7	Planning Reserve Margin % UCAP Basis	25.30%	30.70%	32.80%	33.10%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,901	7,450	7,688	7,751
9	Company Owned, In-State, Non-Intermittent, ZRC	4,022	3,742	3,927	3,749
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	175	713	957	1,198
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	16	21	21	21
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,230	4,493	4,922	4,985
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	412	380	393	394
19	PPA, In-State, Non-Intermittent, ZRC	1,603	1,603	1,550	1,418
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	32	26	26	26
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	408	673	918	991
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	21	21	21	21
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	23	23
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	185	185	185	185
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,249	2,514	2,723	2,663
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	-
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	6,986	7,457	8,037	8,042
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	85	7	350	292

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 3
Page: 1 of 1

Exhibit 3 - Demand Response - Capacity Resources - Spring Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	46	14	60
5		DR RATE GI REDUCE BY	16	5	21
6		DR RATE GI REDUCE TO	257	75	332
9					-
10					-
11	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				412.4
12	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
13		Rate EIP	10	4	14
14		DR CONTRACTS	-	-	-
16		DR RATE GI REDUCE BY	15	5	21
17		DR RATE GI REDUCE TO	257	90	346
20					-
21					-
22	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				380.3
23	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
24		Rate EIP	15	6	21
25		DR CONTRACTS	-	-	-
27		DR RATE GI REDUCE BY	15	6	21
28		DR RATE GI REDUCE TO	257	95	352
31					-
32					-
33	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				393.2
34	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
35		Rate EIP	15	6	21
36		DR CONTRACTS	-	-	-
38		DR RATE GI REDUCE BY	15	6	21
39		DR RATE GI REDUCE TO	257	96	352
42					-
43					-
44	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				394.1

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	82.00%	18	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE therefore they will not be obtaining a MISO queue cycle
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	87.50%	3	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Solar	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	85.44%	17	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-14.00
Cancels Sixth Revised Sheet No. D-14.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.086217*	$ *0.005990*	$*0.092207*	per kWh for Off-Peak kWh between June 1 and September 30
$ *0.132272*	$ *0.008912*	$*0.141184*	per kWh for On-Peak kWh between June 1 and September 30
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-15.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Senior Citizen Provision)

Third Revised Sheet No. D-15.00
Cancels Second Revised Sheet No. D-15.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-16.00)

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 20, 2023

Issued under authority of the Michigan Public Service Commission dated January 19, 2023 in Case No. U-21224

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-16.00
Cancels Fifth Revised Sheet No. D-16.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Device Cycling Program

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning and water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate is determined solely by the Company and Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

(Continued on Sheet No. D-17.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-17.00
Cancels Fourth Revised Sheet No. D-17.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(0.019625)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-18.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page)

Second Revised Sheet No. D-18.00
Cancels First Revised Sheet No. D-18.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To combine and cancel tariff sheets)

First Revised Sheet No. D-19.00
Cancels Original Sheet No. D-19.00

These sheets have been cancelled and are reserved for future use:

Original Sheet No. D-20.00 is cancelled; First Revised Sheet No. D-20.00 is reserved for future use
Original Sheet No. D-21.00 is cancelled; First Revised Sheet No. D-21.00 is reserved for future use
Original Sheet No. D-22.00 is cancelled; First Revised Sheet No. D-22.00 is reserved for future use
First Revised Sheet No. D-23.00 is cancelled; Second Revised Sheet No. D-23.00 is reserved for future use
Original Sheet No. D-24.00 is cancelled; First Revised Sheet No. D-24.00 is reserved for future use
Original Sheet No. D-25.00 is cancelled; First Revised Sheet No. D-25.00 is reserved for future use
Original Sheet No. D-26.00 is cancelled; First Revised Sheet No. D-26.00 is reserved for future use
First Revised Sheet No. D-27.00 is cancelled; Second Revised Sheet No. D-27.00 is reserved for future use
First Revised Sheet No. D-28.00 is cancelled; Second Revised Sheet No. D-28.00 is reserved for future use
Original Sheet No. D-29.00 is cancelled; First Revised Sheet No. D-29.00 is reserved for future use
Original Sheet No. D-30.00 is cancelled; First Revised Sheet No. D-30.00 is reserved for future use
Original Sheet No. D-31.00 is cancelled; First Revised Sheet No. D-31.00 is reserved for future use
First Revised Sheet No. D-32.00 is cancelled; Second Revised Sheet No. D-32.00 is reserved for future use
Original Sheet No. D-33.00 is cancelled; First Revised Sheet No. D-33.00 is reserved for future use
Original Sheet No. D-34.00 is cancelled; First Revised Sheet No. D-34.00 is reserved for future use
First Revised Sheet No. D-35.00 is cancelled; Second Revised Sheet No. D-35.00 is reserved for future use

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-36.00
Cancels Sixth Revised Sheet No. D-36.00

RESIDENTIAL SMART HOURS RATE RSH

Availability:

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$*0.086217*	$*0.005990*	$*0.092207*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak – Summer	$*0.132272*	$*0.008912*	$*0.141184*	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak – Winter	$*0.080987*	$*0.004518*	$*0.085505*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak – Winter	$*0.091448*	$*0.005139*	$*0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-36.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Original Sheet No. D-36.10**
(To reformat page revise Senior Citizen Service Provision)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the *Principal* Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-37.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Seventh Revised Sheet No. D-37.00
Cancels Sixth Revised Sheet No. D-37.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.10)

Monthly Rate: (Contd)

Device Cycling Program

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning *and* water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate is determined solely by the Company *and* Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

(Continued on Sheet No. D-38.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-38.00
Cancels Fourth Revised Sheet No. D-38.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(0.019625)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Residential Electric Vehicle Program reference)

Fourth Revised Sheet No. D-39.00
Cancels Third Revised Sheet No. D-39.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1*., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Eighth Revised Sheet No. D-40.00
Cancels Seventh Revised Sheet No. D-40.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	$*0.072762*	$*0.004114*	$*0.076876*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	$*0.096349*	$*0.006757*	$*0.103106*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	$*0.132272*	$*0.008912*	$*0.141184*	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	$*0.070062*	$*0.003564*	$*0.073626*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	$*0.091004*	$*0.004969*	$*0.095973*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	$*0.091448*	$*0.005139*	$*0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-40.50)

Issued March 22, 2024 by
Garrick J. Rochow,
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Jackson, Michigan

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Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page)

Original Sheet No. D-40.50

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-41.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-41.00
Cancels Fifth Revised Sheet No. D-41.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.50)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the separately metered electric vehicle will be billed under the Residential Nighttime Savers Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 50 amperes or 9.6 kW.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: These charges are applicable to Full Service Customers.

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Device Cycling Program:

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning and water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate in this program is determined solely by the Company and Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental energy savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

(Continued on Sheet No. D-42.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-42.00
Cancels Fifth Revised Sheet No. D-42.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Device Cycling Program: (Contd)

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heating equipment, while customers with air conditioning equipment will experience load management during the summer months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-43.00
Cancels Fourth Revised Sheet No. D-43.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Critical Peak Price:

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(0.019625)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Residential Electric Vehicle Program)

Fourth Revised Sheet No. D-44.00
Cancels Third Revised Sheet No. D-44.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1*., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-44.10
Cancels Fifth Revised Sheet No. D-44.10

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for the first 600 kWh per month during the billing months of June - September
$ *0.132272*	$ *0.008912*	$*0.141184*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Sixth Revised Sheet No. D-44.20
Cancels Fifth Revised Sheet No. D-44.20

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit:	$(8.00)	per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit:	$(30.00)	per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-44.30)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page and revise Senior Citizen Service Provision)

Second Revised Sheet No. D-44.30
Cancels First Revised Sheet No. D-44.30

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.20)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

Senior Citizen Credit:	$(4.00)	per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update prices)

Sixth Revised Sheet No. D-45.00
Cancels Fifth Revised Sheet No. D-45.00

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.094566*	$*0.006246*	$*0.100812*	per kWh for all kWh during the billing months of June-September
$*0.082686*	$*0.004372*	$*0.087058*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

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M.P.S.C. No. 14 – Electric
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(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-46.00
Cancels Fifth Revised Sheet No. D-46.00

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fourth Revised Sheet No. D-47.00
Cancels Third Revised Sheet No. D-47.00

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, (vii) service under the Demand Response Program or (viii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-48.00
Cancels Fifth Revised Sheet No. D-48.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.073219*	$*0.004064*	$*0.077283*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	$*0.098057*	$*0.006297*	$*0.104354*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	$*0.132113*	$*0.007579*	$*0.139692*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	$*0.071813*	$*0.003541*	$*0.075354*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	$*0.091062*	$*0.004740*	$*0.095802*	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-49.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-49.00
Cancels Fifth Revised Sheet No. D-49.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-50.00
Cancels Fifth Revised Sheet No. D-50.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $(0.017673) per kWh for all kWh

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Second Revised Sheet No. D-50.10
Cancels First Revised Sheet No. D-50.10

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Demand Response Program or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-51.00
Cancels Fifth Revised Sheet No. D-51.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$*25.91*	$*1.69*	$*27.60*	per kW for all kW of Peak Demand during the billing months of June-September
$*15.05*	$*1.50*	$*16.55*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.032152*	per kWh for all kWh during the billing months of June-September
$*0.029959*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	$*0.043515*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-52.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Adjustment for Power Factor)

First Revised Sheet No. D-52.00
Cancels Original Sheet No. D-52.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-51.00)

Monthly Rate: (Contd)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	***Penalty***
0.800 to 0.849	*0.50%*
0.750 to 0.799	*1.00%*
0.700 to 0.749	*2.00%*
Below 0.700	*3% first 2 months*

Adjustment for Power Factor shall not be applied when the Peak Demand is based a Minimum Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Peak Demand:

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-53.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-53.00
Cancels Fourth Revised Sheet No. D-53.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit:	$ (0.000690)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

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Consumers Energy Company
(To add Demand Response program eligibility language)

Second Revised Sheet No. D-53.50
Cancels First Revised Sheet No. D-53.50

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-54.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page and revise Term and Form of Contract)

Third Revised Sheet No. D-54.00
Cancels Second Revised Sheet No. D-54.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. *D-53.50*)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, (v) *service under the Demand Response Program or (vi)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-55.00
Cancels Fourth Revised Sheet No. D-55.00

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.089336*	$*0.005350*	$*0.094686*	per kWh for all kWh during the billing months of June-September
$*0.078143*	$*0.003744*	$*0.081887*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.088260*	$*0.005267*	$*0.093527*	per kWh for all kWh during the billing months of June-September
$*0.077219*	$*0.003687*	$*0.080906*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.087186*	$*0.005192*	$*0.092378*	per kWh for all kWh during the billing months of June-September
$*0.076290*	$*0.003634*	$*0.079924*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
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in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-56.00
Cancels Fifth Revised Sheet No. D-56.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $*0.020826* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $*0.009094* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $*0.002634* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-57.00
Cancels Fifth Revised Sheet No. D-57.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $ (0.001741) per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $ (0.001309) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(0.000533) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fifth Revised Sheet No. D-58.00
Cancels Fourth Revised Sheet No. D-58.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule

C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customers as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate may require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, (v) service under the Demand Response Program or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-59.00
Cancels Fourth Revised Sheet No. D-59.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.51*	$*1.81*	$*18.32*	per kW of On-Peak Billing Demand during the billing months of June-September
$*14.26*	$*1.68*	$*15.94*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity	
$*8.17*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.60*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.045475*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.029051*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034757*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.030290*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-60.00
Cancels Fourth Revised Sheet No. D-60.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.33*	$*1.79*	$*18.12*	per kW of On-Peak Billing Demand during the billing months of June-September
$*14.10*	$*1.65*	$*15.75*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity

$*8.04*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.49*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity

$*0.044977*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.028732*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034376*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029959*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.14*	$*1.76*	$*17.90*	per kW of On-Peak Billing Demand during the billing months of June-September
$*13.94*	$*1.63*	$*15.57*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity

$*7.93*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.38*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity

$*0.044461*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.028403*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.033982*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029615*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-61.00
Cancels Fifth Revised Sheet No. D-61.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*5.94*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$*3.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

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Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-62.00
Cancels Fifth Revised Sheet No. D-62.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$(*0.73*)	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$(*0.55*)	per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

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Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-63.00
Cancels Fourth Revised Sheet No. D-63.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges:	**These charges are applicable to Full Service and Retail Open Access Customers.**	
Educational Institution Credit:	$(0.000176)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-64.00
Cancels Fifth Revised Sheet No. D-64.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Third Revised Sheet No. D-65.00
Cancels Second Revised Sheet No. D-65.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

Conditions of Interruption (Contd)
Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption
Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

Interruptible Service Provision – Market-Price Option (GI2):

Availability:

This provision is available to any Full Service GPD customer account willing to designate at least 3,000 kW of On-Peak Billing Demand as Defined Interruptible Capacity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of designated interruptible load available to any single customer, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to designate less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm Capacity and Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 10th of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-66.00
Cancels Sixth Revised Sheet No. D-66.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.037344*	per kWh for all kWh during the billing months of June-September
	$*0.034532*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.036398*	per kWh for all kWh during the billing months of June-September
	$*0.032629*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.032631*	per kWh for all kWh during the billing months of June-September
	$*0.029082*	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise MISO Emergency Electrical Procedure reference)

Second Revised Sheet No. D-67.00
Cancels First Revised Sheet No. D-67.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-68.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Third Revised Sheet No. D-68.00
Cancels Second Revised Sheet No. D-68.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

(Continued on Sheet No. D-69.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Term and Form of Contract)

Second Revised Sheet No. D-69.00
Cancels First Revised Sheet No. D-69.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate: (Contd)

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, (vi) *service under the Demand Response Program or (vii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Schedule of Hours)

Second Revised Sheet No. D-70.00
Cancels First Revised Sheet No. D-70.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.

This rate is not available for Standby service with generators that exceed 550kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to *2:00* PM and *6:00* PM to 11:00 PM
Mid-Peak Hours:	*2:00* PM to *3:00* PM and 5:00 PM to *6:00* PM
High-Peak Hours:	*3:00* PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to *4:00* PM and *8:00* PM to 12:00 AM
Mid-Peak Hours:	*4:00* PM to *5:00* PM and 7:00 PM to *8:00* PM
High-Peak Hours:	*5:00* PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-71.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-71.00
Cancels Fifth Revised Sheet No. D-71.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.067289*	$*0.003182*	$*0.070471*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.082596*	$*0.004711*	$*0.087307*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.108883*	$*0.005865*	$*0.114748*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.124771*	$*0.006144*	$*0.130915*	per kWh during the calendar months of June-September
Off-Peak -Winter	$*0.073740*	$*0.003391*	$*0.077131*	per kWh during the calendar months of October-May
Mid-Peak -Winter	$*0.082502*	$*0.003940*	$*0.086442*	per kWh during the calendar months of October-May
High-Peak -Winter	$*0.087588*	$*0.003941*	$*0.091529*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.066492*	$*0.003133*	$*0.069625*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.081602*	$*0.004638*	$*0.086240*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.107579*	$*0.005775*	$*0.113354*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.123288*	$*0.006049*	$*0.129337*	per kWh during the calendar months of June-September
Off-Peak - Winter	$*0.072869*	$*0.003339*	$*0.076208*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.081524*	$*0.003879*	$*0.085403*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.086554*	$*0.003880*	$*0.090434*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.065692*	$*0.003088*	$*0.068780*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.080610*	$*0.004572*	$*0.085182*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.106276*	$*0.005692*	$*0.111968*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.121801*	$*0.005963*	$*0.127764*	per kWh during the calendar months of June-September
Off-Peak - Winter	$*0.071993*	$*0.003291*	$*0.075284*	per kWh during the calendar months of October-May
Mid-Peak - Winter	$*0.080542*	$*0.003824*	$*0.084366*	per kWh during the calendar months of October-May
High-Peak - Winter	$*0.085515*	$*0.003825*	$*0.089340*	per kWh during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$*5.94*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$*3.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-72.00
Cancels Fourth Revised Sheet No. D-72.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, “school” shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. “College” or “University” shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit: $ (*0.000176*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Second Revised Sheet No. D-72.10
Cancels First Revised Sheet No. D-72.10

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Monthly Rate (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* For customers who participate in the Interruptible Service Provision (GI) on this Rate Schedule, the On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use within on-peak hours during the billing month as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates. For customers who are not enrolled in the GI provision, the On-Peak Billing Demand shall not apply.

The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPTU shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand
For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand
For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

(Continued on Sheet No. D-72.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Original Sheet No. D-72.20**
(To revise prices)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.10)

Monthly Rate (Contd)

Interruptible Service Provision (GI): (Contd)

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	*$(7.00)*	*per kW of On-Peak Billing Demand during the billing months of June-September*
	$(6.00)	*per kW of On-Peak Billing Demand during the billing months of October-May*

(Continued on Sheet No. D-73.00)

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President and Chief Executive Officer,
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fifth Revised Sheet No. D-73.00
Cancels Fourth Revised Sheet No. D-73.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.20)

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:
The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate may require a written contract with a minimum term of one year. Service under this rate shall require a written contract for (i) service under the Educational Institution Service Provision, (ii) service under the Interruptible Service Provision, (iii) service under the Demand Response Program, or (iv) at the option of the Company.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-74.00
Cancels Fourth Revised Sheet No. D-74.00

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing or former metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

The Company may elect to install devices that can enable direct load management, power metering, data collection, near real-time data communication and internet based monitoring. There shall be no cost to the customer associated with the system equipment or installation of the system equipment. The Company reserves the right to remove the system equipment if the customer moves from Rate EIP to another primary rate.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

(Continued on Sheet No. D-74.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Critical Peak Event Determination)

First Revised Sheet No. D-74.50
Cancels Original Sheet No. D-74.50

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Critical Peak Event Determination

A Critical Peak Event *occurs when* the market price *exceeds* an Economic Trigger Price or a *System Integrity Event* is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at $1.00 per kWh during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-75.00)

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dated March 1, 2024
in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-75.00
Cancels Fourth Revised Sheet No. D-75.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.50)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.066902*	$*0.002547*	$*0.069449*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.088051*	$*0.003980*	$*0.092031*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.113410*	$*0.004840*	$*0.118250*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.128630*	$*0.004951*	$*0.133581*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	$*0.074119*	$*0.002771*	$*0.076890*	per kWh during the calendar months of May-October
Mid-Peak-Winter	$*0.085644*	$*0.003162*	$*0.088806*	per kWh during the calendar months of May-October
High-Peak-Winter	$*0.089524*	$*0.003205*	$*0.092729*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.066114*	$*0.002508*	$*0.068622*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.086999*	$*0.003919*	$*0.090918*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.112061*	$*0.004765*	$*0.116826*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.127112*	$*0.004875*	$*0.131987*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	$*0.073246*	$*0.002728*	$*0.075974*	per kWh during the calendar months of May-October
Mid-Peak-Winter	$*0.084637*	$*0.003114*	$*0.087751*	per kWh during the calendar months of May-October
High-Peak-Winter	$*0.088472*	$*0.003155*	$*0.091627*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

(Continued on Sheet No. D-76.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-76.00
Cancels Fifth Revised Sheet No. D-76.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges:

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.065320*	$*0.002472*	$*0.067792*	per kWh during the calendar months of June-September
Low-Peak-Summer	$*0.085947*	$*0.003863*	$*0.089810*	per kWh during the calendar months of June-September
Mid-Peak-Summer	$*0.110710*	$*0.004697*	$*0.115407*	per kWh during the calendar months of June-September
High-Peak-Summer	$*0.125587*	$*0.004805*	$*0.130392*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	$*0.072368*	$*0.002689*	$*0.075057*	per kWh during the calendar months of May-October
Mid-Peak-Winter	$*0.083623*	$*0.003069*	$*0.086692*	per kWh during the calendar months of May-October
High-Peak-Winter	$*0.087414*	$*0.003110*	$*0.090524*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: $*5.94* per kW of Maximum Demand

Charge for Customer Voltage Level 2 (CVL 2)
Capacity Charge: $*3.10* per kW of Maximum Demand

Charge for Customer Voltage Level 1 (CVL 1)
Capacity Charge: $*0.90* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-77.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices and add Interruptible Credit)

Fifth Revised Sheet No. D-77.00
Cancel Fourth Revised Sheet No. D-77.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Monthly Rate (Contd):

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit:

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Term and Form of Contract)

Third Revised Sheet No. D-78.00
Cancels Second Revised Sheet No. D-78.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-77.00)

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate *may* require a written contract with a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Availability and Terms and Conditions)

First Revised Sheet No. D-78.10
Cancels Original Sheet No. D-78.10

LARGE ECONOMIC DEVELOPMENT RATE LED

Availability:

At the Company's discretion, the Large Economic Development Rate is available to (1) new Full Service primary electric customers locating permanent operations within the Company's service territory or (2) existing Full Service primary customers expanding their permanent operations. *As of June 7, 2024, the Large Economic Development Rate is not available to data centers within the Company's service territory who have not already contracted for service under this rate.*

The minimum new or expanded incremental electric service required to contract under the Large Economic Development Rate is 35,000 kW. This rate requires a written contract specifying the terms of the electric service. Upon mutual agreement between the customer and the Company, up to 60 months from the *initial service date for billing purposes* may be granted for the customer to meet the *required 35,000 kW On-Peak Billing Demand*.

This rate is not available to a new customer resulting from a change in ownership of an existing establishment located within the Company's service area. However, if a change in ownership occurs after the customer contracts for service under this rate, the successor may be allowed to fulfill the remainder of the contract.

Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities served by the Company, for standby service, for new or expanded service for resale or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate.

Terms and Conditions:

This rate requires a contract term, the minimum term under this rate is fifteen (15) years from the date initial service is provided under this rate. *The maximum contract term under this rate shall not exceed twenty (20) years from the initial service date for billing purposes.*

If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:

Up to 50% of the contract term	100%
More than 50 to 60% of the contract term	83%
More than 60 to 70% of the contract term	67%
More than 70 to 80% of the contract term	50%
More than 80 to 90% of the contract term	33%
More than 90% to 99.9% of the contract term	17%

For existing customers expanding their operations, the Company will install, operate, and maintain the metering equipment necessary to measure the incremental load to be billed under this rate. The customer will provide the Company with access to its metering equipment. The Company is not obligated to extend, expand, or rearrange its facilities if it determines the existing facilities are adequate to serve the customer's load.

(Continued on Sheet D-78.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Monthly Rate and revise prices and line losses)

Third Revised Sheet No. D-78.20
Cancels Second Revised Sheet No. D-78.20

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:

Customer Voltage Level 1	$*10.94*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$*11.09*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$*11.26*	per kW of On-Peak Billing Demand for all calendar months

Effective for contracts dated on and after June 7, 2024, the monthly Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution. The monthly Production Charge is fixed for the contract term at the rate in effect at the time of contract execution, unless the customer fails to meet the minimum On-Peak Billing Demand required by the Company. Effective for contracts dated on or before June 7, 2024, customers shall pay the monthly Production Charge which was in effect at the time of contract execution.

Transmission Charge:

Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for either the MISO Real-Time or Day Ahead Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh). Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.

Line losses applied to Energy Charge

Voltage Level 1	*3.23*%
Voltage Level 2	*4.68*%
Voltage Level 3	*6.27*%

(Continued on Sheet No. D-78.30)

Issued June 14, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after June 7, 2024

Issued under authority of the Michigan Public Service Commission dated June 6, 2024 in Case No. U-21646

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-78.30
Cancels Fourth Revised Sheet No. D-78.30

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate: (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$0.90	per kW of Maximum Demand
Customer Voltage Level 2:	$3.10	per kW of Maximum Demand
Customer Voltage Level 3:	$5.94	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.55) per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Maximum Demand and On-Peak Billing Demand)

Second Revised Sheet No. D-78.40
Cancels First Revised Sheet No. D-78.40

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision: (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months. *The contract for service under this rate shall specify the customer's projected Maximum Demand.*

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW. *Upon mutual agreement between the customer and the Company, up to 60 months from the initial service date for billing purposes may be granted for the customer to meet the 35,000 kW On-Peak Billing Demand required to be eligible for this rate.*

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credit (REC) Programs.

(Continued on Sheet No. D-78.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Form of Contract and Authority)

First Revised Sheet No. D-78.50
Cancels Original Sheet No. D-78.50

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Form of Contract *and Authority to Require a Minimum On-Peak Billing Demand by Date Certain*:

Service under this rate shall require a written agreement *between the customer and the Company. The Company may require the customer to meet a minimum On-Peak Billing Demand (in addition to the 35,000 kW required to be eligible for this rate) by a date certain, which shall not exceed the customer's projected Maximum Demand specified in the contract. If the customer fails to meet the minimum On-Peak Billing Demand requirement required by its contract for service under this rate, the customer's Production Charge will be reset at the CONE as of the date certain and annually thereafter for the term of the contract, until the customer meets the required minimum On-Peak Billing Demand, after which the Production Charge will be fixed for the remaining term of the contract.*

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update reference to Rate RSM)

First Revised Sheet No. D-79.00
Cancels Original Sheet No. D-79.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

Availability:

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

First Revised Sheet No. D-80.00
Cancels Original Sheet No. D-80.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company**:**

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company**:**

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

M.P.S.C. No. 14 - Electric
Consumers Energy Company
(To update Administrative Rule)

Second Revised Sheet No. D-81.00
Cancels First Revised Sheet No. D-81.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation with a combined onsite nameplate capacity greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company's electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

"Standby" service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer's generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

"Standby Demand" is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this Rate Schedule.

This rate is not available to Retail Open Access.

Nature of Service

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B., Parallel Operation Requirements. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-Hertz, single-phase or three-phase (as governed by Rule B8., Interconnection and *Distributed Generation* Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 Volts or less but equal to or greater than 2,400 Volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-82.00)

Issued May 9, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after April 25, 2023

Issued under authority of the
Michigan Public Service Commission
dated April 24, 2023
in Case No. U-20890

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Real Power Losses, System Access Charge Power Supply Standby Charges and revise prices)

Sixth Revised Sheet No. D-82.00
Cancels Fifth Revised Sheet No. D-82.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of *2.01%* plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

Delivery Standby Charges

System Access Charge:	$100.00	per generator installation per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$*5.94*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$*3.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-83.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-83.00
Cancels Fourth Revised Sheet No. D-83.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer’s billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Second Revised Sheet No. D-83.10
Cancels First Revised Sheet No. D-83.10

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit:	$ (0.90)	per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Transmission Interconnect Credit)

Fifth Revised Sheet No. D-84.00
Cancels Fourth Revised Sheet No. D-84.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. *D-83.10*)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year. *Service under the Demand Response Program shall require a contract.*

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

First Revised Sheet No. D-84.10
Cancels Original Sheet No. D-84.10

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

Availability:

Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.

The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.

Contracted Capacity and Annual Nominations:

The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.

The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.

At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.

(Continued on Sheet D-84.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Rate LTILRR)

Original Sheet No. D-84.20

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.

Monthly Rate:

System Access Charge:	*Fixed charge per billing month as specified in the customer's written agreement for electric service*

Power Supply Charges:

Capacity Charge:	*$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Reserved Capacity Charge:	*$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Excess Capacity Charge:	*$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level*
Interruptible Credit:	*Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge*
Energy Charge:	*The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service*

(Continued on Sheet No. D-84.30)

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Interruptible Service Provision)

First Revised Sheet No. D-84.30
Cancels Original Sheet No. D-84.30

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.20)

Power Supply Charges: (Contd)

Excess Energy Charge:	$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges

Transmission Charges:

Transmission Charge:	Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service

Delivery Charges:

Distribution Charges:	Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00

Interruptible Service Provision

The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-84.40)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Annual Power Test Requirement)

First Revised Sheet No. D-84.40
Cancels Original Sheet No. D-84.40

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.30)

Interruptible Service Provision (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.

A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-84.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Rate LTILRR)

Original Sheet No. D-84.50

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.40)

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.

Definitions Applicable to the Long Term Industrial Load Retention Rate:

Annual Forecast Capacity
Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.

Annual Load Factor
Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.

Average Demand
Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.

Capacity Charge
The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.

Energy Charge
The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.

Excess Capacity
The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.

(Continued on Sheet No. D-84.60)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Rate LTILRR)

Original Sheet No. D-84.60

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.50)

Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)

Firm Contracted Capacity
The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.

Interruptible Peak Billing Demand
The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.

Interruptible Service Capacity
Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.

Interval Data Meters
Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.

Maximum Contracted Capacity
The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.

Maximum Monthly Demand
The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.

MISO Planning Year
MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.

Reserved Capacity
The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR

Site
An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-85.00
Cancels Fourth Revised Sheet No. D-85.00

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.062471*	$0.000000	$*0.062471*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

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Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-86.00
Cancels Sixth Revised Sheet No. D-86.00

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$*0.082650*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.030658*	$0.000000	$*0.030658*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.062986*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-87.00

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-86.00)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-88.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule.

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines, supply the energy, control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaries, the Company shall furnish, install and own all equipment comprising the unmetered lighting system. The Company shall supply the energy, and renew and maintain the entire equipment. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be furnished, owned, installed and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company’s general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-89.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall install new luminaires and associated facilities under this rate, or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.

B. At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest standard size high-pressure sodium luminaire at no cost to the customer. If requirements for installations make it necessary for the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain due to federal or state requirements, the Company shall cover the cost of the bulb and the customer shall be responsible for all other expenses as a contribution. For conversions completed with normal Company maintenance such as replacement of bulbs on a routine schedule or due to failure, then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution. If other light upgrading is also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

   Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.

C. Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company, the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.

D. Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.

E. For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.

F. For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

G. If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.

(Continued on Sheet No. D-90.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.00
Cancels Third Revised Sheet No. D-90.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-89.00)

Monthly Rate

Transitional Rates, effective *March 18, 2022* through June 30, 2022:

The charge per luminaire per month shall be

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)			Service Charge per Luminaire (4)			
Type of Luminaire	Watts	Watts Including Ballast (2)	Lumens	Non-Capacity	Capacity	Total	Fixture Charge per Luminaire (4)
Mercury Vapor (3)	100	128	3,500	$9.72	$0.00	$9.72	$3.00
Mercury Vapor (3)	175	209	7,500	13.28	0.00	13.28	3.00
Mercury Vapor (3)	250	281	10,000	16.45	0.00	16.45	3.00
Mercury Vapor (3)	400	458	20,000	*24.23*	0.00	*24.23*	3.00
Mercury Vapor (3)	700	770	35,000	37.96	0.00	37.96	3.00
Mercury Vapor (3)	1,000	1,080	50,000	*51.59*	0.00	*51.59*	3.00
High-Pressure Sodium (3)	70	83	5,000	7.74	0.00	7.74	3.00
High-Pressure Sodium	100	117	8,500	9.23	0.00	9.23	3.00
High-Pressure Sodium	150	171	14,000	11.61	0.00	11.61	3.00
High-Pressure Sodium (3)	200	247	20,000	*14.96*	0.00	*14.96*	3.00
High-Pressure Sodium	250	318	24,000	*18.07*	0.00	*18.07*	3.00
High-Pressure Sodium	400	480	45,000	*25.20*	0.00	*25.20*	3.00
Fluorescent (3)	380	470	20,000	*24.76*	0.00	*24.76*	3.00
Incandescent (3)	202	202	2,500	*12.98*	0.00	*12.98*	3.00
Incandescent (3)	305	305	4,000	17.51	0.00	17.51	3.00
Incandescent (3)	405	405	6,000	*21.90*	0.00	*21.90*	3.00
Incandescent (3)	690	690	10,000	*34.44*	0.00	*34.44*	3.00
Metal Halide (3)	150	170	9,750	*11.56*	0.00	*11.56*	3.00
Metal Halide (3)	175	210	10,500	13.33	0.00	13.33	3.00
Metal Halide (3)	250	290	15,500	*16.84*	0.00	*16.84*	3.00
Metal Halide (3)	400	460	24,000	24.33	0.00	24.33	3.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *22.6*% Power Supply Charge and a *77.4*% Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 15.6% Power Supply Charge and a 84.4% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-90.10)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered
on and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-90.10
Cancels Second Revised Sheet No. D-90.10

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$*0.41*	$0.00	$*0.41*	$*10.39*	$*10.80*
25-34 W	Per Light	$*0.62*	$0.00	$*0.62*	$*11.02*	$*11.64*
35-44 W	Per Light	$*0.84*	$0.00	$*0.84*	$*11.64*	$*12.48*
45-54 W	Per Light	$*1.05*	$0.00	$*1.05*	$*12.27*	$*13.32*
55-64 W	Per Light	$*1.26*	$0.00	$*1.26*	$*12.90*	$*14.16*
65-74 W	Per Light	$*1.47*	$0.00	$*1.47*	$*13.52*	$*14.99*
75-84 W	Per Light	$*1.68*	$0.00	$*1.68*	$*14.15*	$*15.83*
85-94 W	Per Light	$*1.89*	$0.00	$*1.89*	$*14.77*	$*16.66*
95-104 W	Per Light	$*2.10*	$0.00	$*2.10*	$*15.40*	$*17.50*
105-114 W	Per Light	$*2.32*	$0.00	$*2.32*	$*16.03*	$*18.35*
115-124 W	Per Light	$*2.53*	$0.00	$*2.53*	$*16.65*	$*19.18*
125-134 W	Per Light	$*2.74*	$0.00	$*2.74*	$*17.28*	$*20.02*
135-144 W	Per Light	$*2.95*	$0.00	$*2.95*	$*17.90*	$*20.85*
145-154 W	Per Light	$*3.16*	$0.00	$*3.16*	$*18.53*	$*21.69*
155-164 W	Per Light	$*3.37*	$0.00	$*3.37*	$*19.16*	$*22.53*
165-174 W	Per Light	$*3.59*	$0.00	$*3.59*	$*19.78*	$*23.37*
175-184 W	Per Light	$*3.80*	$0.00	$*3.80*	$*20.41*	$*24.21*
185-194 W	Per Light	$*4.01*	$0.00	$*4.01*	$*21.03*	$*25.04*
195-204 W	Per Light	$*4.22*	$0.00	$*4.22*	$*21.66*	$*25.88*
205-214 W	Per Light	$*4.43*	$0.00	$*4.43*	$*22.29*	$*26.72*
215-224 W	Per Light	$*4.64*	$0.00	$*4.64*	$*22.91*	$*27.55*
225-234 W	Per Light	$*4.85*	$0.00	$*4.85*	$*23.54*	$*28.39*
235-244 W	Per Light	$*5.07*	$0.00	$*5.07*	$*24.17*	$*29.24*
245-254 W	Per Light	$*5.28*	$0.00	$*5.28*	$*24.79*	$*30.07*
255-264 W	Per Light	$*5.49*	$0.00	$*5.49*	$*25.42*	$*30.91*
265-274 W	Per Light	$*5.70*	$0.00	$*5.70*	$*26.04*	$*31.74*
275-284 W	Per Light	$*5.91*	$0.00	$*5.91*	$*26.67*	$*32.58*
285-294 W	Per Light	$*6.12*	$0.00	$*6.12*	$*27.30*	$*33.42*
295-304 W	Per Light	$*6.34*	$0.00	$*6.34*	$*27.92*	$*34.26*
305-314 W	Per Light	$*6.55*	$0.00	$*6.55*	$*28.55*	$*35.10*
315-324 W	Per Light	$*6.76*	$0.00	$*6.76*	$*29.17*	$*35.93*
325-334 W	Per Light	$*6.97*	$0.00	$*6.97*	$*29.80*	$*36.77*
335-344 W	Per Light	$*7.18*	$0.00	$*7.18*	$*30.43*	$*37.61*
345-354 W	Per Light	$*7.39*	$0.00	$*7.39*	$*31.05*	$*38.44*
355-364 W	Per Light	$*7.60*	$0.00	$*7.60*	$*31.68*	$*39.28*
365-374 W	Per Light	$*7.82*	$0.00	$*7.82*	$*32.30*	$*40.12*
375-384 W	Per Light	$*8.03*	$0.00	$*8.03*	$*32.93*	$*40.96*
385-394 W	Per Light	$*8.24*	$0.00	$*8.24*	$*33.56*	$*41.80*
395-404 W	Per Light	$*8.45*	$0.00	$*8.45*	$*34.18*	$*42.63*
405-414 W	Per Light	$*8.66*	$0.00	$*8.66*	$*34.81*	$*43.47*
415-424 W	Per Light	$*8.87*	$0.00	$*8.87*	$*35.44*	$*44.31*
425-434 W	Per Light	$*9.09*	$0.00	$*9.09*	$*36.06*	$*45.15*
435-444 W	Per Light	$*9.30*	$0.00	$*9.30*	$*36.69*	$*45.99*
445-454 W	Per Light	$*9.51*	$0.00	$*9.51*	$*37.31*	$*46.82*
455-464 W	Per Light	$*9.72*	$0.00	$*9.72*	$*37.94*	$*47.66*
465-474 W	Per Light	$*9.93*	$0.00	$*9.93*	$*38.57*	$*48.50*
475-484 W	Per Light	$*10.14*	$0.00	$*10.14*	$*39.19*	$*49.33*

(Continued on Sheet No. D-90.20)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 15, 2024

Issued under authority of the
Michigan Public Service Commission
dated March 1, 2024
in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.20
Cancels Third Revised Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-91.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

Fourth Revised Sheet No. D-91.00
Cancels Third Revised Sheet No. D-91.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.20)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms, Surcharges, Power Supply Cost Recovery (PSCR) Factor and Securitization Charges:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00, Surcharges shown on Nos. D-2.00 through D-5.00, PSCR Factor shown on Sheet No. D-6.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10*.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

(Continued on Sheet No. D-92.00)

Issued December 19, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for bills rendered on and after the Company's January 2024 Billing Month

Issued under authority of the Michigan Public Service Commission dated December 17, 2020 in Case No. U-20889

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Streetlighting Outage Credit language)

First Revised Sheet No. D-92.00
Cancels Original Sheet No. D-92.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-91.00)

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the capacity requirements in watts of the lamp(s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Rate GU-LED)

First Revised Sheet No. D-93.00
Cancels Original Sheet No. D-93.00

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

Nature of Service:

Company-Owned Option

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:

Company-Owned Option

Following execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company. *A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-94.00)

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 1, 2021

Issued under authority of the Michigan Public Service Commission dated December 17, 2020 in Case No. U-20697

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Company-Owned Conversion Credit)

Fifth Revised Sheet No. D-94.00
Cancels Fourth Revised Sheet No. D-94.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $(*8.11*) per month

(Continued on Sheet No. D-94.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Second Revised Sheet No. D-94.10
Cancels First Revised Sheet No. D-94.10

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.00)

Monthly Rate (Contd)

Transitional Unmetered Lighting Rate GU-LED Charges, effective *March 18, 2022* through June 30, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$8.32*	*$8.66*
25-34 W	Per Light	*$0.51*	$0.00	*$0.51*	$8.98	*$9.49*
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$9.64	*$10.32*
45-54 W	Per Light	*$0.86*	$0.00	$0.86	*$10.31*	*$11.17*
55-64 W	Per Light	*$1.03*	$0.00	$1.03	*$10.97*	*$12.00*
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$11.63	*$12.83*
75-84 W	Per Light	*$1.37*	$0.00	*$1.37*	*$12.30*	$13.67
85-94 W	Per Light	*$1.54*	$0.00	*$1.54*	*$12.96*	$14.50
95-104 W	Per Light	*$1.71*	$0.00	*$1.71*	*$13.62*	$15.33
105-114 W	Per Light	*$1.88*	$0.00	*$1.88*	$14.28	*$16.16*
115-124 W	Per Light	*$2.05*	$0.00	*$2.05*	*$14.95*	*$17.00*
125-134 W	Per Light	*$2.23*	$0.00	*$2.23*	*$15.61*	$17.84
135-144 W	Per Light	*$2.40*	$0.00	*$2.40*	$16.27	*$18.67*
145-154 W	Per Light	*$2.57*	$0.00	*$2.57*	*$16.94*	$19.51
155-164 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.60*	*$20.34*
165-174 W	Per Light	*$2.91*	$0.00	*$2.91*	*$18.26*	*$21.17*
175-184 W	Per Light	*$3.08*	$0.00	*$3.08*	*$18.93*	*$22.01*
185-194 W	Per Light	*$3.25*	$0.00	*$3.25*	*$19.59*	*$22.84*
195-204 W	Per Light	*$3.42*	$0.00	*$3.42*	*$20.25*	*$23.67*
205-214 W	Per Light	*$3.59*	$0.00	*$3.59*	*$20.92*	*$24.51*

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$5.32*	*$5.66*
25-34 W	Per Light	*$0.51*	$0.00	*$0.51*	$5.98	*$6.49*
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$6.64	*$7.32*
45-54 W	Per Light	*$0.86*	$0.00	$0.86	*$7.31*	*$8.17*
55-64 W	Per Light	*$1.03*	$0.00	$1.03	*$7.97*	*$9.00*
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$8.63	*$9.83*
75-84 W	Per Light	*$1.37*	$0.00	*$1.37*	*$9.30*	$10.67
85-94 W	Per Light	*$1.54*	$0.00	*$1.54*	*$9.96*	$11.50
95-104 W	Per Light	*$1.71*	$0.00	*$1.71*	*$10.62*	$12.33
105-114 W	Per Light	*$1.88*	$0.00	*$1.88*	$11.28	*$13.16*
115-124 W	Per Light	*$2.05*	$0.00	*$2.05*	*$11.95*	*$14.00*
125-134 W	Per Light	*$2.23*	$0.00	*$2.23*	*$12.61*	$14.84
135-144 W	Per Light	*$2.40*	$0.00	*$2.40*	$13.27	*$15.67*
145-154 W	Per Light	*$2.57*	$0.00	*$2.57*	*$13.94*	$16.51
155-164 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.60*	*$17.34*
165-174 W	Per Light	*$2.91*	$0.00	*$2.91*	*$15.26*	*$18.17*
175-184 W	Per Light	*$3.08*	$0.00	*$3.08*	*$15.93*	*$19.01*
185-194 W	Per Light	*$3.25*	$0.00	*$3.25*	*$16.59*	*$19.84*
195-204 W	Per Light	*$3.42*	$0.00	*$3.42*	*$17.25*	*$20.67*
205-214 W	Per Light	*$3.59*	$0.00	*$3.59*	*$17.92*	*$21.51*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-94.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 18, 2022

Issued under authority of the Michigan Public Service Commission dated March 17, 2022 in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-94.20
Cancels Second Revised Sheet No. D-94.20

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$*0.41*	$0.00	$*0.41*	$*10.39*	$*10.80*
25-34 W	Per Light	$*0.62*	$0.00	$*0.62*	$*11.02*	$*11.64*
35-44 W	Per Light	$*0.84*	$0.00	$*0.84*	$*11.64*	$*12.48*
45-54 W	Per Light	$*1.05*	$0.00	$*1.05*	$*12.27*	$*13.32*
55-64 W	Per Light	$*1.26*	$0.00	$*1.26*	$*12.90*	$*14.16*
65-74 W	Per Light	$*1.47*	$0.00	$*1.47*	$*13.52*	$*14.99*
75-84 W	Per Light	$*1.68*	$0.00	$*1.68*	$*14.15*	$*15.83*
85-94 W	Per Light	$*1.89*	$0.00	$*1.89*	$*14.77*	$*16.66*
95-104 W	Per Light	$*2.10*	$0.00	$*2.10*	$*15.40*	$*17.50*
105-114 W	Per Light	$*2.32*	$0.00	$*2.32*	$*16.03*	$*18.35*
115-124 W	Per Light	$*2.53*	$0.00	$*2.53*	$*16.65*	$*19.18*
125-134 W	Per Light	$*2.74*	$0.00	$*2.74*	$*17.28*	$*20.02*
135-144 W	Per Light	$*2.95*	$0.00	$*2.95*	$*17.90*	$*20.85*
145-154 W	Per Light	$*3.16*	$0.00	$*3.16*	$*18.53*	$*21.69*
155-164 W	Per Light	$*3.37*	$0.00	$*3.37*	$*19.16*	$*22.53*
165-174 W	Per Light	$*3.59*	$0.00	$*3.59*	$*19.78*	$*23.37*
175-184 W	Per Light	$*3.80*	$0.00	$*3.80*	$*20.41*	$*24.21*
185-194 W	Per Light	$*4.01*	$0.00	$*4.01*	$*21.03*	$*25.04*
195-204 W	Per Light	$*4.22*	$0.00	$*4.22*	$*21.66*	$*25.88*
205-214 W	Per Light	$*4.43*	$0.00	$*4.43*	$*22.29*	$*26.72*
215-224 W	Per Light	$*4.64*	$0.00	$*4.64*	$*22.91*	$*27.55*
225-234 W	Per Light	$*4.85*	$0.00	$*4.85*	$*23.54*	$*28.39*
235-244 W	Per Light	$*5.07*	$0.00	$*5.07*	$*24.17*	$*29.24*
245-254 W	Per Light	$*5.28*	$0.00	$*5.28*	$*24.79*	$*30.07*
255-264 W	Per Light	$*5.49*	$0.00	$*5.49*	$*25.42*	$*30.91*
265-274 W	Per Light	$*5.70*	$0.00	$*5.70*	$*26.04*	$*31.74*
275-284 W	Per Light	$*5.91*	$0.00	$*5.91*	$*26.67*	$*32.58*
285-294 W	Per Light	$*6.12*	$0.00	$*6.12*	$*27.30*	$*33.42*
295-304 W	Per Light	$*6.34*	$0.00	$*6.34*	$*27.92*	$*34.26*
305-314 W	Per Light	$*6.55*	$0.00	$*6.55*	$*28.55*	$*35.10*
315-324 W	Per Light	$*6.76*	$0.00	$*6.76*	$*29.17*	$*35.93*
325-334 W	Per Light	$*6.97*	$0.00	$*6.97*	$*29.80*	$*36.77*
335-344 W	Per Light	$*7.18*	$0.00	$*7.18*	$*30.43*	$*37.61*
345-354 W	Per Light	$*7.39*	$0.00	$*7.39*	$*31.05*	$*38.44*
355-364 W	Per Light	$*7.60*	$0.00	$*7.60*	$*31.68*	$*39.28*
365-374 W	Per Light	$*7.82*	$0.00	$*7.82*	$*32.30*	$*40.12*
375-384 W	Per Light	$*8.03*	$0.00	$*8.03*	$*32.93*	$*40.96*
385-394 W	Per Light	$*8.24*	$0.00	$*8.24*	$*33.56*	$*41.80*
395-404 W	Per Light	$*8.45*	$0.00	$*8.45*	$*34.18*	$*42.63*
405-414 W	Per Light	$*8.66*	$0.00	$*8.66*	$*34.81*	$*43.47*
415-424 W	Per Light	$*8.87*	$0.00	$*8.87*	$*35.44*	$*44.31*
425-434 W	Per Light	$*9.09*	$0.00	$*9.09*	$*36.06*	$*45.15*
435-444 W	Per Light	$*9.30*	$0.00	$*9.30*	$*36.69*	$*45.99*
445-454 W	Per Light	$*9.51*	$0.00	$*9.51*	$*37.31*	$*46.82*
455-464 W	Per Light	$*9.72*	$0.00	$*9.72*	$*37.94*	$*47.66*
465-474 W	Per Light	$*9.93*	$0.00	$*9.93*	$*38.57*	$*48.50*
475-484 W	Per Light	$*10.14*	$0.00	$*10.14*	$*39.19*	$*49.33*

(Continued on Sheet No. D-94.30)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 15, 2024

Issued under authority of the
Michigan Public Service Commission
dated March 1, 2024
in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-94.30
Cancels Third Revised Sheet No. D-94.30

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-95.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Streetlighting Outage Credit language)

Fourth Revised Sheet No. D-95.00
Cancels Third Revised Sheet No. D-95.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.30)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered LED Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered LED Lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rates)

Sixth Revised Sheet No. D-96.00
Cancels Fifth Revised Sheet No. D-96.00

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.074181*	$*0.002717*	$*0.076898*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.026586*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-97.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 15, 2024

Issued under authority of the
Michigan Public Service Commission
dated March 1, 2024
in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-97.00

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-96.00)

Monthly Rate: (Contd)

Determination of kWh:

The monthly charge shall be the per kWh total of the Power Supply and Delivery Charges as shown above based on the capacity requirements in Kilowatts of the lamp(s), associated ballast(s) and control equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption. At the Company's option, such service may be metered and the metered kWh used as the basis for billing. The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

For dusk to midnight service for energy-only unmetered lighting, the monthly charge per kWh shall be 130% of the sum of the Secondary Energy Charge and Distribution Charge per kWh for secondary service. The annual kWh shall be based on the actual burning hours. The monthly kWh for billing shall be the annual kWh adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be 50% of the total kWh so calculated. The kWh for continuous, nonintermittent devices shall be 100% of the total kWh so calculated. No reduction in kWh shall be made for devices not operated 24 hours per day, or not operated every day.

The kWh of devices used for the control of school traffic, and operated not more than six hours per day during the school year only, shall be 10% of the continuous or cyclical kWh calculated.

The kWh for CATV Power Supply Units shall be 50% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The kWh for Wireless Access and Security Camera Power Supply Units shall be 100% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The Company may, at its option, install test meters for the purpose of determining the monthly kWh usage to be used for billing purposes.

(Continued on Sheet No. D-98.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Renewable Energy Credit (REC) Program)

First Revised Sheet No. D-98.00
Cancels Original Sheet No. D-98.00

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-97.00)

Monthly Rate (Contd)

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, plus any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

Designees for Copies of Contracts

The Company designates a primary and secondary contact to assist with requested customer contract review. The designated contacts are:

Primary Designee:

Name: Sarah Jorgensen
Email: sarah.jorgensen@cmsenergy.com
Office Phone: (517) 788-2349

Secondary Designee:

Name: Natalie Busack
Email: NATALIE.BUSACK@cmsenergy.com
Office Phone: (517) 788-0931

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 28

2028/2029 MPSC Staff Capacity Demonstration Results

MPSC
MICHIGAN PUBLIC SERVICE COMMISSION

Capacity Demonstration Results

Planning Year 2028/29

Case No. U-21775

May 12, 2025

MPSC Staff

LARA
LICENSING AND REGULATORY AFFAIRS

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Executive Summary

All Michigan load serving entities (LSE)s required to file capacity demonstrations with the Michigan Public Service Commission (MPSC) for planning year 2028/29 pursuant to MCL 460.6w and the Commission Order in Case No. U-21775 have filed. Staff has audited the filings, contracts, and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2028/29, except one agency representing municipalities which will be discussed further below.

Staff projects that the Midcontinent Independent System Operator, Inc. (MISO) Local Resource Zone (LRZ) 7, which consists of Michigan's lower peninsula excluding the southwest corner of the state located in Indiana Michigan Power Company's (I&M) service territory, will have sufficient resources to meet its planning reserve margin requirements and local clearing requirements (LCR) in all four seasons for the compliance year (2028/29).[1]. For MISO LRZ 1 and LRZ 2, the majority of which are in other states not subject to MCL 460.6w, Staff does not have sufficient detail to project the capacity positions of these zones. Staff projects that the I&M service territory in Michigan will have sufficient capacity to meet PJM's requirements for the prompt and compliance years.

The most recent OMS-MISO Survey results indicate that MISO will have an 11.8GW deficit to a 2.4 GW surplus by Summer 2028, depending on the amount of potential new capacity able to be added each year (the low projection assumes 2.3 GW/year and the high projection assumes 6.1 GW/year). Projections for other seasons of 2028/29 Planning Year are as follows: Fall ranges from .9 GW deficit to 14.3 GW surplus, Winter ranges from .4 to 15.6 GW surplus, and Spring ranges from 8.8GW deficit to 6.4GW surplus. In addition, projections for each subregion in Summer and Winter were published, showing the North/Central subregion ranging from a 10.4 GW deficit to 0.6 GW surplus in Summer 2028 and 0.3 to 11.3 GW surplus in Winter 2028/29[2] The MISO-OMS Survey no longer projects future capacity positions for individual LRZs, however the survey does show individual LRZ's potential to meet their LCR in each season of the prompt year. Both LRZ 1 and 2 show sufficient capacity to meet obligations in Planning Year 2025/26.

MISO's 2025/26 Planning Resource Auction (PRA) results indicated sufficient capacity at the regional, subregional, and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance. Systemwide surplus (above the target Planning Reserve Margin or PRM) offered into the auction dropped 43%

[1] This projection is based on the filed capacity demonstrations and information from MISO available at the time of this report and is dependent on several variables including but not limited to: load growth, delays in completion of planned resources, and changes to MISO's resource adequacy construct.

[2] 2024 OMS-MISO Survey Results, June 20, 2024.

compared to last summer, despite the lower target PRM (7.9% vs 9.0% last year). In terms of GW, the systemwide surplus capacity in the summer has reduced from ~6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW this Planning Year.

MISO noted in its 2025 PRA Results[3] that new capacity additions did not keep pace with the capacity lost due to retirements/suspensions, decreased accreditation of certain resources, and fewer available external resources. MISO continues to reform its resource adequacy construct under the Reliability Imperative to address emerging risks due to fleet transition, new load additions, and retirements of dispatchable units.

[3] MISO 2025/26 PRA Auction Results

Background

On September 15, 2017, in Case No. U-18197, the Commission directed all Michigan LSEs to file capacity demonstrations annually pursuant to MCL 460.6w. This report outlines the results of the capacity demonstrations filed for planning year 2028/29 as directed by the Commission in Case No. U-21775 and represents the eighth annual capacity demonstration report. Prior year capacity demonstration reports can be found in the following dockets:

- 2021/22: Case No. U-18441
- 2022/23: Case No. U-20154
- 2023/24: Case No. U-20590
- 2024/25: Case No. U-20886
- 2025/26: Case No. U-21099
- 2026/27: Case No. U-21225
- 2027/28: Case No. U-21393

In Case No. U-21775, for the 2028/29 planning year, the Commission ordered[4] investor-owned utilities with one million or more customers[5] to file capacity demonstrations by February 24, 2025, investor-owned utilities with less than one million customers[6] by March 3, 2025, and alternative electric suppliers (AES),[7] cooperatives (co-ops), and municipal utilities on or before March 17, 2025.

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

Pre-Demonstration Process

As with previous years, Staff offered LSEs the opportunity to meet with Staff to discuss the capacity demonstration requirements and review relevant materials prior to the

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[4] August 22, 2024 Order in Case No. U-21775.

[5] Consumers Energy Company, DTE Electric Company.

[6] Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company-Wisconsin, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company.

[7] AEP Energy Inc, American Rural Cooperative, BP Energy Retail Company, LLC, Calpine Energy Solutions LLC f/k/a Noble Americas Energy Solutions LLC, CMS ERM Michigan LLC, Constellation NewEnergy Inc, Dillon Power LLC, Direct Energy Business f/k/a NRG Energy Inc., Direct Energy Services LLC, Energy Harbor LLC, Energy International Power Marketing Corporation, Energy Services Providers Inc., ENGIE Power & Gas f/k/a Plymouth Rock Energy LLC, Interstate Gas Supply LLC, Just Energy Solutions Inc, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Spartan Renewable Energy, Texas Retail Energy, LLC U.P. Power Marketing LLC, and Wolverine Power Marketing Cooperative Inc.

final filing deadlines. Several LSEs met with Staff remotely and clarified the process before filing reports in the docket. Staff found that the pre-filing consultations were helpful in resolving questions prior to filing. Staff will continue to offer pre-filing consultations each year to resolve potential issues prior to the filing deadlines.

Capacity Demonstration Filings

On or before February 24, 2025, capacity demonstrations were received from DTE Electric Company and Consumers Energy Company. On or before March 3, 2025, capacity demonstration filings were received from Alpena Power Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company (UPPCO). Many LSEs filed confidential information under seal as part of the electric utilities' filings. Staff reviewed this information and met with LSEs as needed.

On or before March 17, 2025, capacity demonstration filings were received from American Rural Cooperative, Bayfield Electric, Calpine Energy Solutions, LLC., City of Escanaba, City of Stephenson, City of Wakefield, Cloverland Electric Cooperative, CMS ERM, Constellation New Energy Inc., Croswell Light and Power, Daggett Electric Department, NRG Energy f/k/a Direct Energy Business, LLC, Energy Harbor, Michigan Public Power Agency, Michigan South Central Power Agency (MSCPA), Newberry Water and Light Board, Union City Electric Department, Wolverine Power Supply Cooperative, and WPPI Energy.

Several AESs filed letters in Case No. U-21775 indicating that they are currently not serving customers in Michigan.[8]

All LSEs, apart from MSCPA (see below), were able to procure the necessary capacity to demonstrate compliance for the current planning year in all four seasons. Two LSEs' filings indicated a shortage of capacity in the compliance year compared with projections of forecasted growth. MCL 460.6w requires all LSEs to demonstrate enough resources to cover *prompt* year obligations, and both entities met this requirement. After reviewing these filings, staff has determined that these entities have demonstrated sufficient capacity, and notes that both entities are in negotiations to acquire the appropriate amount of capacity needed to meet their forecasted growth.

Staff conducted an audit for each capacity demonstration filing received and requested additional information from the LSEs when necessary. Staff has reviewed all contracts included in capacity demonstrations from AESs as well as most of the contracts from co-ops, electric utilities, and municipalities. In addition to the required

[8] AEP Energy Inc., BP Energy Retail Company, LLC, Dillion Power LLC, Direct Energy Services LLC, Energy Services Providers, Inc., Interstate Gas Supply LLC, Just Energy, ENGIE Power and Gas, Energy International Power Marketing, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Texas Retail Energy, LLC, and UP Power Marketing.

compliance year (PY 2028/29), most demonstrations included updates for the 2025/26 planning year through the 2028/29 planning year.[9] The order opening the docket in U-21775 directed all entities to file data for the prompt and interim years, as well as the compliance year. Most entities complied but some of the municipal and cooperative utilities continued to only provide information for the compliance year (PY 2028/29). For these entities, Staff was able to estimate the amount of capacity available for the prompt year and interim years by projecting the amount included for planning year 2028/29 backwards for three years.

Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings. Staff uses this information to help track changes in load and resources and to project the zonal resource adequacy more closely in these years. In addition, Staff recommends the Commission direct LSEs to provide MECT screenshots of their load obligations (PRMR/PLC) to facilitate the Storage Target calculation used to comply with Public Act 235.[10]

At the time of this report MSCPA[11] did not have rights to sufficient capacity to meet its obligations. MSCPA is in the process of negotiating a bilateral contract to meet the deficiency with the intent to submit a revised capacity demonstration filing by the self-imposed deadline of September 1, 2025, showing that MSCPA has sufficient resources to meet its requirements. Staff meet with MSCPA on April 30, 2025 to discuss and to urge MSCPA to complete the process as soon as possible. Staff is prepared to review any future filings by MSCPA and file a memo to this docket updating the Commission on the issue following MSCPAs revised filing.

[9] The required demonstrations for planning years 2026/2027 and 2027/28 were made in the 2023 capacity demonstration (Case No. U-21225) and the 2024 capacity demonstration (Case No. U-21393).

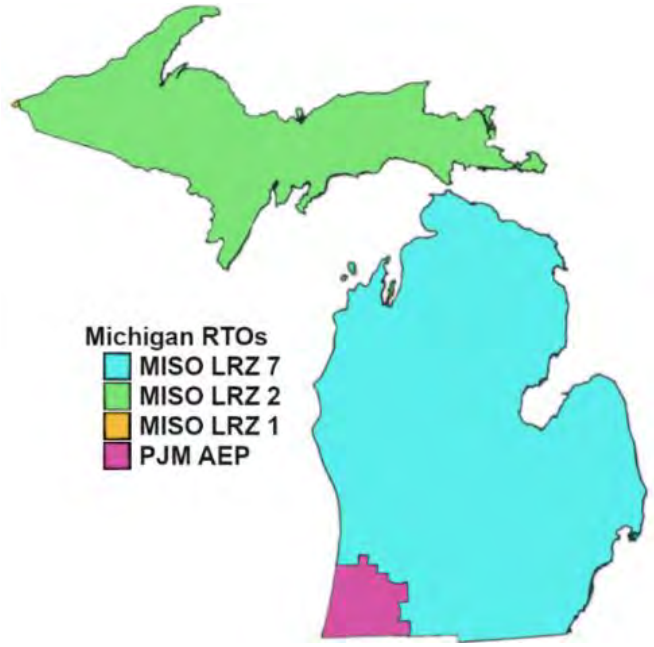
[10] See January 23, 2025 Order in Case No. U-21571

[11] MSCPA member municipal utilities include Clinton, Coldwater, Hillsdale, and Marshall.

Overview of Zonal Adequacy

Michigan contains load that spans two regional transmission operators (RTO)s: MISO and PJM. The majority of Michigan's load is located within MISO and is split between several LRZs. The exception is the Southwest corner of the Lower Peninsula which is located within the PJM RTO through I&M's service territory. PJM and MISO have different resource adequacy constructs and capacity obligations. The different RTO regions in Michigan are illustrated in Figure 1.

Figure 1: RTO Zonal Regions in Michigan



MISO Resource Adequacy

Michigan LSEs serve load in MISO Local Resource Zones 1, 2, and 7. MISO's capacity construct is for the upcoming year (prompt year) only. LSEs must demonstrate sufficient resources to meet their current prompt year requirement four years forward to comply with MCL 460.6w.

MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin percentage (PRM) necessary to meet the North American Electric Reliability Corporation's (NERC) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP), self-schedule, Reliability Based Demand Curve (RBDC) opt-out (new this planning year, see more detail below), paying the capacity deficiency charge, or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to utilize other participation options or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations, and thus need to purchase additional resources.

Within MISOs resource adequacy construct, the Planning Reserve Margin Requirement (PRMR) and the Local Clearing Requirement (LCR) must be satisfied to meet the LOLE standard. The Initial PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or in the subregion (MISO North/Central or MISO South) given subregional transmission constraints

The LCR is the minimum capacity for a zone required to be located within the zone to meet the LOLE standard, while accounting for the LRZ's ability to import. The LCR is for the entire zone collectively, and not a requirement for individual LSEs; there is currently no LCR requirement applicable to individual LSEs in Michigan pursuant to MCL 460.6w. The LCR is determined by performing a LOLE analysis on each zone individually, to determine the Local Reliability Requirement (LRR), or the resources a zone would need to meet the loss-of-load standard if it were separated from MISO. Separately, MISO determines the import and export limits for each zone by performing a seasonal transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values, which are then adjusted by the amount of controllable exports to non-MISO load to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The ZIA is an input to the LCR calculation, and the LCR, CEL, and CIL, and subregional constraints are inputs to the PRA clearing process.

In Planning Year 2023/24, MISO implemented a seasonal resource adequacy requirement for each summer, fall, winter and spring season and a seasonal accredited capacity (SAC) methodology for certain resources participating in MISO's

PRA to align with real time availability and planned outages. Staff reviewed these changes with participants in its 2022 and 2023 technical conferences as a part of the Commission's June 22, 2022 Order in U-21099, and results of these activities included requiring entities to file capacity demonstrations showing resources to meet obligations in all four seasons, modifications to the filing timeline, and adoption of ISO-neutral language into the process and requirements. Commencing PY 2024/25, the Commission's July 26, 2023 Order in U-21393 directed LSEs in MISO to demonstrate seasonal capacity obligations based on the MISO seasonal resource adequacy construct. LSEs are obligated to demonstrate enough capacity (owned or contracted) to meet that LSE's capacity obligation for each season. The specific capacity obligation for each season will be the LSE's prompt year (upcoming year) Initial Planning Reserve Margin Requirement for each respective season.

On June 27, 2024, the FERC accepted MISO's Reliability-Based Demand Curve (RBDC) tariff revision to incorporate sloped demand curves into the PRA. The vertical demand curve used in the PRA since the 2009/2010 Planning Year failed to properly value incremental capacity, did not facilitate efficient investment and retirement decisions necessary to maintain the resources needed to meet system reliability, and was inefficient at pricing capacity accurately.[12]

If a LRZ does not have sufficient resources to meet its seasonal requirements, the entire LRZ clears at the LRZ's seasonal Cost of New Entry (CONE) value. If a LRZ does not have sufficient resources to meet its seasonal requirements in more than one season, the PRA clearing price would be determined as described in section 69A.7.1 of Tariff Module E-1. CONE varies from zone to zone and changes from year to year but for reference, for 2025/26 CONE is $130,930/MW-year ($358.71/MW-day) in Zone 7.[13] The PRA clearing price being set at CONE would have economic ramifications and should provide a signal to entities with responsibilities regarding resource adequacy within the zone. However, it is important to note that MISO's resource adequacy construct is based on probabilistic determinations and failure to meet the requirements of the resource adequacy construct would not mean that the LRZ in question will experience a loss of load event. It simply means the probability of such a loss of load event would exceed the generally accepted criteria that govern the resource adequacy planning process.

Details on the Reliability-Based Demand Curve Tariff Revision

MISO introduced sloped demand curves in its resource adequacy construct through the implementation of RBDCs in the 2025 PRA. Specifically, MISO utilizes distinct sloped demand curves at both the systemwide and subregional levels. The systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. As a result, for each season, MISO develops one systemwide RBDC and two

[12] Direct Testimony of Todd Ramey, FERC ER23-2977, p.8
[13] MISO Cost of New Entry (CONE) and Net CONE Calculation for PY 2025/2026

subregional RBDCs, one for each subregion aka Planning Area (MISO North/Central and MISO South). Ultimately, MISO seeks to develop and employ RBDCs at the LRZ level; however due to the complexity of developing another ten curves for each season, they have delayed this effort until a later date. Each sloped demand curve is developed using its respective Marginal Reliability Impact (MRI) Curve, expressed in MWh/UCAP MW-year, which provides information about the value of the reliability improvements brought about by additional capacity, and a Scaling Factor to support annual revenue prices driving toward annualized Net CONE when the system is at the reliability requirement in all four seasons. Net CONE, expressed in $/UCAP MW-year, is the net annualized cost to develop new capacity resources. For more information and detail on development of RBDCs, see the Reliability-Based Demand Curves Conceptual Design White Paper.[14]

The RBDCs fundamentally change the objective function of the PRA, from minimizing as-offered costs to minimizing the difference between supply offers and demand offers to maximize social surplus. The clearing quantities may vary from the initial PRMR, but the value of the reliability contribution of any additional MWs cleared must be greater than or equal to the cost of procuring those MWs. The PRA is conducted using an optimization to simultaneously complete the following tasks: (1) meet the supply demand balance both for MISO and for each of the two Planning Areas (MISO North/Central and MISO South); (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs; and (4) respect the Sub-Regional Power Balance Constraint. Step 1 of the auction clearing process solves an optimization problem to identify which type of RBDC produces a higher MW obligation for a given subregion, share-of-Systemwide or Subregional. Step 2 of the process solves the clearing and pricing problem based on the RBDC identified in step 1 and outputs both the resource clearing (Final PRMR) and the auction clearing price (ACP) for each LRZ and External Resource Zone. A final step verifies the solution found in step 2. The auction clearing price is determined by where the supply offer curve meets the applicable RBDC, and is equal to the marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for an LRZ, and the marginal cost of financially binding Subregional Export Constraints and Subregional Import Constraints. For more information on auction clearing under RBDC see Appendix M of MISO's Business Practice Manual 11.[15]

Within the RBDC proposal, MISO established the RBDC Opt-Out mechanism, which allows an LSE to opt out of the PRA if the Relevant Electric Retail Rate Authority (RERRA) does not deny the opt out plan. LSEs who choose the RBDC Opt-Out provision cannot include a partial opt-out, shall be locked-in for three consecutive years, and must include the RBDC Opt-Out Adder % in their obligation. The RBDC Opt-Out Adder % is based on a seasonal average of RBDC clearing for the prior three

[14] Reliability-Based Demand Curves Conceptual Design White Paper
[15] MISO BPM-011-r31 Appendix M

planning years, or a simulated PRA clearing if prior year RBDC-based PRA clearing is not available. In PY 2025/26, no LSEs chose to opt out in any LRZ in MISO.

Future Resource Adequacy Construct Changes

MISO has recently filed or is currently working on FERC filings to address issues and challenges related to demand side resources, including Demand Response Participation Rules Enhancements, Elimination of Dual Registration, DR and ER reforms (formerly known as LMR reforms). Also, MISO aims to implement enhanced resource adequacy risk modeling and a Direct Loss-of-Load (DLOL) accreditation methodology (FERC Docket ER24-1638-000 filed 3/28/2024) beginning in planning year 2028/29. MISO has committed to publishing indicative accreditation results based on the DLOL methodology prior to each Planning Resource Auction, starting with Planning Year 2025-2026[16]. These reforms will align PRMR with accreditation of all resource classes. MISO continues its work on the PRMR piece of the reforms, therefore indicative PRMR values under DLOL are not yet available. Several LSEs inquired whether DLOL accreditation methodology should be used in this case since the demonstration year aligns with the first year of DLOL implementation. Staff recommended and continues to recommend that demonstrating LSEs follow the prompt year MISO resource adequacy construct. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.

The compliance year capacity obligations (PY 2028/29) that are demonstrated for in this case are based off an LSE's prompt year (PY 2025/26) requirement. Changes to load, resources, and MISO procedures in the upcoming years can lead to discrepancies between an LRZ having sufficient capacity to meet its four-year forward Michigan requirements and not having enough capacity to meet MISO's requirements when the prompt year arrives.

MISO – Local Resource Zone 7

Figure 2 shows historical annual MISO capacity requirements for LRZ 7. This data is taken from the respective annual MISO LOLE Study Reports.

[16] Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results

Figure 2: Annual MISO LOLE Report Data LRZ 7

Planning Year	Source	LRR[17]	CIL[18]	LCR (ZRCs)[19]
2013/14	MISO 2013 LOLE Report	25,305	4,576	20,729
2014/15	MISO 2014 LOLE Report	24,815	3,884	20,931
2015/16	MISO 2015 LOLE Report	24,710	3,813	20,897
2016/17	MISO 2016 LOLE Report	24,715	3,813	21,309
2017/18	MISO 2017 LOLE Report	24,654	3,320	21,334
2018/19	MISO 2018 LOLE Report	24,545	3,785	20,760
2019/20	MISO 2019 LOLE Report	24,845	3,211	21,634
2020/21	MISO 2020 LOLE Report	25,370	3,200	22,170
2021/22	MISO 2021 LOLE Report	25,054	4,888	20,166
2022/23	MISO 2022 LOLE Report	24,115	3,749	20,366
2023/24[20]	MISO 2023 LOLE Report	24,428	5,087	19,341
2024/25	MISO 2024 LOLE Report	24,558	4,500	19,271
2025/26	MISO 2025 LOLE Report	23,250	3,569	19,681

These numbers typically change slightly between the LOLE Study and the PRA, primarily due to updated load forecasting used in the PRA but can be used to see how the capacity requirements have changed over time. Changes in these requirements can have economic and reliability impacts and will continue to be monitored.

In its seasonal construct, MISO includes an LRR, ZIA, and PRMR for each zone for each season. The current year MISO requirements are shown in comparison with Planning Year 2024-25 requirements in Appendix B.

The difference between a zone's PRMR and its LCR is sometimes referred to as Effective Capacity Import Limit (ECIL). The ECIL is not a MISO defined term and is not representative of a physical import limitation. To meet the loss of load standard and avoid the auction clearing price being set at CONE, a zone must have enough resources located within the zone to meet its LCR even if the LCR exceeds the PRMR. Note the year-over-year decrease in CIL in PY 2025/26. This decrease is driven by generation and transmission changes in LRZ 7 Local Balancing Authorities (LBAs), their neighboring LBAs, and the LBAs adjacent to

[17] **Local Reliability Requirement**. Representative of the resources required for LRZ 7 to meet the LOLE standard when modeled as an island (no imports). MISO Loss of Load Expectation Study Report, Table 2-1 through 2-4.
[18] **Capacity Import Limit**. Representative of the ability of an LRZ to import capacity from areas outside of that LRZ. MISO Loss of Load Expectation Study Report, Tables ES-3 through ES-6.
[19] **Local Clearing Requirement**. Representative of the minimum resources that must be located within a specific zone for that zone to meet the reliability standard. Calculated as shown in Table 1.1 of MISO Loss of Load Expectation Study Report.
[20] Values for summer season starting Planning Year 2023/24. Other seasons shown in Appendix C.

these neighbors. Historically, Michigan utilities have assumed a CIL of approximately 3200 MW for input in capacity expansion modeling conducted during the development of Integrated Resource Plans and other planning exercises.

Figure 3 shows a comparison of LRZ 7 aggregated resources demonstrated, plus known undemonstrated resources likely to still be available, for each season in the 2028/29 planning year and MISO's resource adequacy requirement for PY 2025/26. Appendix C contains seasonal capacity position tables for the prompt, interim, and demonstration years. These numbers represent Staff's current projection based on the capacity demonstration filings and MISO publications at the time of this report although the information is subject to change for all forward years. Unless otherwise noted, resources and resource requirements in this report are in Unforced Capacity (UCAP) Megawatts (MW), equal to Zonal Resource Credits (ZRCs).

Figure 3: U-21775 Results – PY 2028/29 LRZ 7 Capacity Position (ZRCs)

Line #		Summer	Autumn	Winter	Spring
1	Planning Reserve Margin Requirements (PRMR)	21,228	20,494	16,124	19,853
2	Local Reliability Requirement (LRR)	23,250	23,312	20,262	21,619
3	Capacity Import Limit (CIL)	3,569	5,115	4,762	5,166
4	Zonal Import Ability (ZIA)	3,569	5,115	4,762	5,166
5	Local Clearing Requirement (LCR) (L1-L4)	19,681	18,197	15,500	16,453
6	Total Owned	17,981	16,378	14,542	16,263
7	Total PPA Contracts	4,321	4,086	2,981	4,175
8	Total ZRC Contracts	610	573	309	543
9	Total Qualified Demand Response	1,502	845	793	879
10	Total Resources (sum of L6 through L9)	24,415	21,883	18,624	21,860
11	LCR Demonstrated Position (L10-L5)	4,734	3,686	3,124	5,406
12	PRMR Demonstrated Position (L10-L1)	3,187	1,389	2,501	2,006
13	Net Undemonstrated Capacity	241	264	538	323
14	Anticipated LCR Position (L11+L13)	4975	3950	3662	5729
15	Anticipated PRMR Position (L12+L13)	3428	1653	3039	2329

(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.

(2) PY 2025 LRR from PRA Data and held constant at prompt year value (LRR=LCR+ZIA).

(3) PY 2025 CIL from PRA Data and held constant at prompt year value.

(4) PY 2025 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

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

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

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

Prompt Year (PY 2025/26) and Compliance Year (PY 2028/29)

For the prompt year (PY 2025/26), based on the PRA Results posted April 28, 2025,[21] LRZ 7's summer Initial PRMR is 21,228 ZRCs and the LCR is 19,681 ZRCs. The total LRZ 7 resources offered in the PRA for the summer season in the prompt year is 20,884 ZRCs, which exceeds the anticipated LCR by 2,203 ZRCs, however falls short of the zone's portion of PRMR. The zone relied on 785.5 ZRCs of external resources to meet its resource adequacy requirement target. Other seasons' data is shown in Appendix C.

All resources offered into the North/Central subregion were cleared, and the final PRMRs as determined through auction clearing were greater than the initial targets (Initial PRMRs) in all seasons. In other words, the auction cleared above seasonal reliability targets, representing additional reliability value at cost-competitive prices. The "effective" PRMs are calculated from the Final PRMRs (determined by auction clearing):

2025 PRA Results	Initial PRM	Final Cleared PRM
Summer	7.9%	9.8%
Fall	14.9%	17.5%
Winter	18.4%	24.5%
Spring	25.3%	26.8%

Based on the resources included in the capacity demonstration filings for PY 2028/29 Staff projects LRZ 7 to have a surplus of resources compared to the projected LCR in all four seasons, as shown in Figure 4. It is important to note that these projections are subject to change. A few examples of things that could change include load forecasts, resource availability and performance, and MISO policies and practices.

MISO has previously provided projections of both PRMR and LRR into the compliance year from the prompt year. These calculations were not available to Staff at the time of its report. In absence of projected PRMR/LRR values, Staff has assumed these values remain constant for the purposes of this comparison.

Interim Years (PY 2026/27 & PY 2027/28)

Appendix C also includes data and projections for each season in the interim years, PY 2026/27 & PY 2027/28. This information is derived using the same methodology as described for the compliance year. Comparing those projected requirements to the demonstrated and undemonstrated resources in LRZ 7, results in a capacity surplus for both years compared to the projected LCRs. This information is based on the best information currently available to Staff, but includes several assumptions and, again, is subject to change. Similar to the

[21] 2025 MISO PRA Results, accessed May 2, 2025

compliance year, likely changes include new forecasts, unknown resource additions or subtractions, changes in generator performance, increased or decreased zonal import ability, seasonal variability, and/or changes to MISO requirements. It is also worth noting that the capacity margin looks to be tight in 2026/27 across all four seasons with the tightest capacity position in the Fall season.

MISO – Local Resource Zone 2

MISO's LRZ 2 encompasses almost the entire upper peninsula of Michigan as well as northern and eastern Wisconsin. MISO LRZ 2 has seasonal CILs of 4,370 MWs in Summer, 6,537 MWs in Fall, 6,522 MWs in Winter, and 6,439 MWs in Spring.[22] MISO does not define MW capacity imports or export limits between states within the boundaries of the same MISO LRZ. Considering LRZ 2 includes LSEs from Wisconsin (not subject to MCL 460.6w), the data available to Staff for LRZ 2 from capacity demonstration filings is not comprehensive enough to project a zonal capacity position as Staff did in its analysis of LRZ 7. Nevertheless, all Michigan LSEs serving load within MISO LRZ 2 demonstrated sufficient resources to meet their requirements.

The 2025 MISO PRA results indicate an installed capacity surplus in the 2025/26 planning year for LRZ 2.[23]

MISO – Local Resource Zone 1

A very small fraction of Michigan's upper peninsula load is located in LRZ 1. Northern States Power, Bayfield Electric Cooperative, and the City of Wakefield municipal utility have less than 37 MW combined in MISO LRZ 1. All LSEs in LRZ 1 demonstrated sufficient capacity to meet their obligations for PY 2028/29. The 2025/26 MISO PRA results show sufficient capacity for each season in the 2025/26 planning year, relying on a small amount of imports to meet their resource adequacy target in Winter and Spring. [24]

[22] Id
[23] Id
[24] Id

PJM Resource Adequacy

A few LSEs in Michigan serve load within the PJM RTO. These LSEs are still subject to the requirements of MCL 460.6w requiring sufficient capacity for four years forward in planning year 2028/29. PJM LSEs demonstrate sufficiency by providing evidence that the LSE complies with its PJM obligations.

LSEs in the PJM service territory must meet capacity obligations either through participation in PJM's Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) plan. The FRR plan is an alternative to the RPM, where an LSE must demonstrate to PJM that it has enough resources to cover its projected load plus an additional reserve requirement. Both the RPM and the FRR resources are subject to monetary penalties if they fail to maintain PJM's reliability standard. PJM's resource adequacy construct is based on annual requirements.

The largest LSE in PJM is Indiana Michigan Power Company (I&M).[25] I&M elects to file an FRR plan each year. I&M's most recent capacity demonstration indicates that the company plans to continue with the PJM FRR plan barring any major FERC-ordered changes. Staff reviewed I&M's filing and finds that they have sufficient resources to meet its obligations at PJM.

In addition to I&M's capacity demonstration, Staff also reviewed information of cooperative and municipal utility obligations in the Michigan portion of PJM's territory for planning year 2028/29. The results are displayed in the table below.

Figure 4: PJM Capacity Demonstration Summary

Item	PY 2025/26	PY 2026/27	PY 2027/28	PY 2028/29
Utility Total Planning Resources, MW	3825	4462	4695	4359
Other PJM Resources, MW	295.2	336.8	350.8	321.8
Total PJM Resources, MW	4120.2	4798.8	5045.8	4680.8

Staff expects that the LSEs in the Michigan portion of PJM will continue to meet the PJM capacity obligations based on information included in individual capacity demonstrations. If PJM LSEs were to encounter an unanticipated shortfall in the immediate future, Staff expects that it would be accommodated through the procurement of reserve resources by market purchases. As market conditions may change over time, Staff will continue to monitor the resource adequacy of the PJM

[25] Indiana Michigan Power Company is an electric operating company of American Electric Power Company, Inc. (AEP). I&M is a wholly owned subsidiary of AEP and is operated as a single utility in the American Electric Power System (AEP System).

region and the capacity plans of Michigan LSEs located within the PJM territory. As reaffirmed in the Company's most recent IRP, filed in Case No U-21189,[26] Staff does not anticipate I&M to have any issues meeting capacity obligations.

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

The North American Electric Reliability Corporations 2024 Long-Term Reliability Assessment categorizes PJM as having elevated risk level post 2026, with resource additions not keeping up with generator retirements and demand growth, and winter season replacing summer as the higher-risk period due to generator performance and fuel supply issues.[27]

The PJM Base Residual Auction (BRA) schedule has experienced delays awaiting FERC action on capacity auction related issues. The following timeline shows the published BRA schedule of auctions every six months until they can get back to the original schedule (every May, three years in advance of the delivery year):

- July 2025 2026/27 BRA
- December 2025 2027/28 BRA
- June 2026 2028/29 BRA
- December 2026 2029/30 BRA

Commencing in Planning Year 2025/26, PJM has introduced a more robust risk model while simultaneously implementing the Effective Load Carry Capability (ELCC) methodology for all assets. These changes are expected to result in lower accreditation amounts for demand-side resources and lower load obligations for every entity.

LSE Capacity Demonstration Results (PY 2028/2029)

Staff appreciates the time and effort made by all Michigan LSEs to comply with the provisions of MCL 460.6w, as well as to comply with the questions, audits, contract reviews, and requests for additional information throughout this process. The LSE capacity demonstration results are reported for planning year 2028/2029 because, following the initial capacity demonstration which covered four years, only the fourth year forward is required for compliance. As previously described in its September 15, 2017 order in Case No. U-18197, the Commission requested a table be included in this

[26] MPSC Case No. U-21189, Direct Testimony of Stephan F. Baker, p. 7, February 28, 2022.
[27] NERC 2024 Long-Term Reliability Assessment

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

Figure 5: Resource Breakdown (%) by Supplier Type Planning Year 2028/29 - Summer

Supplier Type	Owned	DR	Contract – PPA	Contract - ZRC	Auction
Muni/Co-Op Aggregate	58.5%	0.3%	29.3%	8.9%	3.0%
AES Aggregate	0.7%	0.2%	2.1%	96.5%	0.5%
Utility Aggregate	71.8%	5.3%	16.1%	1.8%	5.0%

Demand Response

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

Demand response played a prominent role in LSEs' integrated resource plan filings, where DR is required to be considered along with traditional supply side resources for meeting capacity needs. MCL 460.6t directs Staff to complete a statewide study of DR potential in Michigan every five years, and the most current Michigan Demand Response Potential Study was issued on September 24, 2021.[28] In addition, the Commission approved Michigan Integrated Resource Planning Parameters on November 21, 2017 in Case No. U-18418 that include provisions regarding including DR options in future integrated resource plans and Staff is currently working to update those parameters.

The DR levels assumed in both Consumers Energy's and DTE Electric's current integrated resource plans[29] are reflected in their capacity demonstration filing. Staff will continue to monitor these plans and the use of DR in Michigan for the foreseeable future.

[28] Michigan Demand Response Statewide Potential Study (2021-2040), Guidehouse, September 24, 2021.

[29] DTE's current IRP filed and approved in MPSC Case No. U-21193.
CE's current IRP filed in MPSC Case No. U-21090.

Demand Response Aggregation

Pursuant to the September 15, 2017 Order in Case No. U-18369, the Commission affirmed that AESs may offer DR programs to their customers through a curtailment service provider (CSP) or third-party aggregator. The Commission made this determination in the context of finding that it will continue to review DR programs offered by AESs as part of the capacity demonstration process.

As the Relevant Electric Retail Regulatory Authority (RERRA), the Commission is aware of aggregation of approximately 85 ZRCs of DR offered into the 2025 MISO capacity market. Staff continues to work with CSPs, ARCs and MISO to ensure that aggregated DR's load modifications are accounted for when dispatched on MISO's coincident peak and continues to monitor the discussions taking place regarding FERC Order 2222.

ZRC Contracts

Staff recommended that forward ZRC contracts be used for capacity demonstration purposes to specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. This year's demonstration shows an increase in the percentage of ZRC contracts utilized this year by the utilities, municipal utilities and cooperatives compared to last year.

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

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

AES Load Switching

Staff requested that any AES who experienced load switching during this time provide a signed affidavit confirming the increase or reduction in their load compared to the PLC data provided by the utility with their capacity demonstration that contained the amount of load switching for each planning year. Each supplier contracting for additional customer load provided a copy of its affidavit confirming this transaction to the supplier that was losing the load to

be accounted for in both suppliers' demonstrations. The load switching process was made more complex with the change to a seasonal construct.

Staff continues to see an increase in the amount of load switching among entities. To better organize and facilitate the filing process, Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff is able to easily cross check that the load is being accounted for.

Capacity Retirements and Additions

NERC's 2024 Long Term Reliability Assessment shows added resource capacity on the Bulk Power System (BPS) falling short of industry projections the year prior[30], illustrating an over-projection of natural gas, solar PV, and wind resources and giving evidence to project delays. The Lawrence Berkeley National Laboratory published results of an interconnection queue study in April 2024 assessing that only 19% of the projects (and just 14% of capacity) that submitted interconnection requests from 2000 to 2018 reached commercial operations by the end of 2023.[31] In recognition of the interconnection backlog risk, some RTOs have taken steps to address these issues, including PJM's Reliability Resource Initiative, MISO's work to reduce queue cycle times through automation, and MISO's Expedited Resource Addition Study (ERAS) process which is currently awaiting FERC approval.

The state of Michigan continues to follow national trends showing a tightening capacity position due to the scheduled retirements outpacing the buildout of replacement capacity. Staff had the opportunity to meet with several LSEs to discuss their filings and many expressed concerns about the dwindling amount of capacity available in the compliance year, especially season-specific contracts and bilateral contracts in general. Various factors could cause delays for new additions, including broad economic factors such as supply chain constraints, labor shortages, high component prices, etc., as well as delays associated with obtaining permitting, regulatory approval, or interconnection queue delays. The issue may be further exacerbated should demand increase faster than expected due to unanticipated loads such as data centers, as well as electrification of the building and transportation sectors. Staff has noted a significant number of planned resources used as demonstrated capacity in this case and recent previous cases that have not come to fruition in the demonstration year as planned, with estimates in the range of 900-1000MW/year removed from the list of planned resources due to delays or cancellations. There are many instances of

[30] NERC 2024 LTRA, p.24.
[31] Queued Up: 2024 Edition, Lawrence Berkely National Laboratory, April 2024.

this occurring with IRP-identified resources, consequently Staff met with both large investor-owned utilities to discuss this issue in depth and determine what actions can be taken to overcome the delays. One of these utilities indicated they are in the process of quantifying project delays and terminations, and early estimates showed an average delay of ~1.5 years past Commercial Operation Date (COD) and a project failure rate greater than 25%.

A portion of the capacity from the Palisades Nuclear Power Plant was included as demonstrated capacity starting in Spring 2026. The remainder of the capacity from Palisades is being contracted by an LSE in Indiana. However, all the capacity from Palisades would provide resource adequacy benefits to MISO LRZ 7 and be counted towards meeting the LCR for LRZ 7. Re-opening of this plant is conditional on approval from the Nuclear Regulatory Commission (NRC).

Conclusion and Recommendations

All Michigan LSEs required to file capacity demonstrations with the Michigan Public Service Commission for planning year 2028/29 pursuant to MCL 460.6w and the August 22, 2024 Commission Order in Case No. U-21775 have filed. Staff has audited the filings, contracts and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2028/29, with the exception of one agency representing municipalities, as previously described.

Staff appreciates the cooperation of all Michigan LSEs with respect to this process and the willingness to provide data and answer questions necessary for Staff to complete its review.

A summary of recommendations included in this report is below:

1. Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings.
2. Staff recommends the Commission direct all LSEs to provide MECT screenshot of their prompt load obligations (PRMR/PLC) to facilitate the Storage Target calculation used to comply with Public Act 235.
3. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.
4. Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, so Staff is able to cross check that the load is being accounted for.

Appendix A

Planning Year 2028/29 Resource Breakdown (%) by Individual Supplier[32]

LSE	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Supplier 1	30%	0%	63%	0%	7%
Supplier 2	0%	24%	0%	76%	0%
Supplier 3	0%	0%	100%	0%	0%
Supplier 4	0%	0%	0%	100%	0%
Supplier 5	61%	8%	30%	0%	0%
Supplier 6	55%	0%	21%	18%	6%
Supplier 7	0%	0%	0%	100%	0%
Supplier 8	49%	51%	0%	0%	0%
Supplier 9	0%	0%	0%	100%	0%
Supplier 10	0%	0%	0%	100%	0%
Supplier 11	0%	0%	0%	100%	0%
Supplier 12	9%	9%	81%	0%	0%
Supplier 13	0%	0%	100%	0%	0%
Supplier 14	0%	0%	100%	0%	0%
Supplier 15	49%	4%	6%	1%	41%
Supplier 16	0%	0%	100%	0%	0%
Supplier 17	0%	0%	0%	100%	0%
Supplier 18	87%	6%	6%	0%	0%
Supplier 19	67%	0%	35%	-2%	0%
Supplier 20	51%	8%	41%	0%	0%
Supplier 21	44%	25%	32%	0%	0%
Supplier 22	73%	0%	21%	6%	0%
Supplier 23	100%	0%	0%	0%	0%
Supplier 24	0%	0%	0%	100%	0%

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

Appendix B

LRZ 7 Local Clearing Requirement								
	A	B	C=A+B	D	E=C*D	F	G	H=E-F-G
	Zonal Coincident Peak Forecast (ZCPF)	Transmission Losses	LRZ Peak Demand	LRR UCAP/LRZ Peak Demand from LOLE	Local Reliability Requirement (LRR)	Zonal Import Ability (ZIA)	Controllable Exports	**Local Clearing Requirement (LCR)**
Summer								
2025	19791.9	638.8	20430.7	1.138	23250.1	3569	0	19681.1
2024	19867.5	606.7	20474.2	1.161	23770.5	4490	10	19270.5
Δ (MW)			-43.5		-520.4	-921		410.6
Δ (%)			-0.2%		-2.2%	-20.5%		2.1%
Fall								
2025	17957.3	617.6	18574.9	1.255	23311.5	5115	0	18196.5
2024	17752.9	434.2	18187.1	1.311	23843.3	4390	10	19443.3
Δ (MW)			387.8		-531.8	725		-1246.8
Δ (%)			2.1%		-2.2%	16.5%		-6.4%
Winter								
2025-26	13626.6	376.2	14002.8	1.447	20262.1	4762	0	15500.1
2024-25	13542	305	13847	1.607	22252.1	4656	10	17586.1
Δ (MW)			155.8		-1990.1	106		-2086.1
Δ (%)			1.1%		-8.9%	2.3%		-11.9%
Spring								
2026	15983.2	407.5	16390.7	1.319	21619.3	5166	0	16453.3
2025	15702	376	16078	1.322	21255.1	4883	10	16362.1
Δ (MW)			312.7		364.2	283		91.2
Δ (%)			1.9%		1.7%	5.8%		0.6%

Appendix C

U-21775 Results - LRZ 7 Summer Capacity Position (ZRCs)					
Line #	Summer Values	PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	21228	21228	21228	21228
2	Local Reliability Requirement (LRR)	23250	23250	23250	23250
3	Zonal Import Ability (ZIA)	3569	3569	3569	3569
4	Local Clearing Requirement (LCR)	19681	19681	19681	19681
5	Total Owned	15782	16271	17086	17981
6	Total PPA Contracts	3015	3336	4284	4321
7	Total ZRC Contracts	829	507	800	610
8	Total Qualified Demand Response	1208	1308	1463	1502
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	20834	21422	23633	24415
10	LCR Demonstrated Position (Line 9 - Line 4)	1153	1741	3952	4734
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-394	194	2405	3187
12	Net Undemonstrated Zone 7 Capacity	-18	347	-112	241
13	Anticipated LCR Position (Line 10 + Line 12)	1135	2088	3840	4975
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(412)	541	2293	3428
(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.					
(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.					
(4) PY 2025 LCR from PRA Data and held constant at prompt year value.					
(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.					
(10) LCR position based on demonstrated resources only.					
(11) PRMR position based on demonstrated resources only.					
(12) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small number of resources included in the capacity demonstration that are no longer available due to recent events.					
(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.					
(14) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resource to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to meet its PRMR.					

U-21775 Results - LRZ 7 Autumn Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	20494	20494	20494	20494
2	Local Reliability Requirement (LRR)	23312	23312	23312	23312
3	Zonal Import Ability (ZIA)	5115	5115	5115	5115
4	Local Clearing Requirement (LCR)	18197	18197	18197	18197
5	Total Owned	14996	15318	16797	16378
6	Total PPA Contracts	2802	3113	4083	4086
7	Total ZRC Contracts	936	569	759	573
8	Total Qualified Demand Response	793	780	816	845
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19526	19780	22458	21883
10	LCR Demonstrated Position (Line 9 - Line 4)	1330	1583	4261	3686
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-968	-556	1964	1389
12	Net Undemonstrated Zone 7 Capacity	-130	263	-70	264
13	Anticipated LCR Position (Line 10 + Line 12)	1200	1846	4191	3950
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(1097)	(452)	1893	1653

(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2025 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

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

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

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

U-21775 Results - LRZ 7 Winter Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	16124	16124	16124	16124
2	Local Reliability Requirement (LRR)	20262	20262	20262	20262
3	Zonal Import Ability (ZIA)	4762	4762	4762	4762
4	Local Clearing Requirement (LCR)	15500	15500	15500	15500
5	Total Owned	15568	15313	15954	14542
6	Total PPA Contracts	2307	2521	3177	2981
7	Total ZRC Contracts	857	510	630	309
8	Total Qualified Demand Response	730	738	769	793
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19461	19082	20530	18624
10	LCR Demonstrated Position (Line 9 - Line 4)	3961	3582	5029	3124
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	3338	2958	4406	2501
12	Net Undemonstrated Zone 7 Capacity	-65	306	90	538
13	Anticipated LCR Position (Line 10 + Line 12)	3896	3887	5120	3662
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	3272	3264	4496	3039

(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2025 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

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

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

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

U-21775 Results - LRZ 7 Spring Capacity Position (ZRCs)					
Line #		PY 2025	PY 2026	PY 2027	PY 2028
1	Planning Reserve Margin Requirements (PRMR)	19853	19853	19853	19853
2	Local Reliability Requirement (LRR)	21619	21619	21619	21619
3	Zonal Import Ability (ZIA)	5166	5166	5166	5166
4	Local Clearing Requirement (LCR)	16453	16453	16453	16453
5	Total Owned	14609	15739	16992	16263
6	Total PPA Contracts	2861	3711	4213	4175
7	Total ZRC Contracts	931	584	771	543
8	Total Qualified Demand Response	802	802	847	879
9	Total Resources (Line 5 + Line 6 + Line 7 + Line 8)	19203	20837	22823	21860
10	LCR Demonstrated Position (Line 9 - Line 4)	2749	4383	6369	5406
11	PRMR Demonstrated Capacity Position (Line 9 - Line 1)	-651	983	2969	2006
12	Net Undemonstrated Zone 7 Capacity	-99	282	-50	323
13	Anticipated LCR Position (Line 10 + Line 12)	2650	4665	6319	5729
14	Anticipated PRMR Capacity Position (Line 11 + Line 12)	(750)	1265	2919	2329

(1) PY 2025 PRMR from PRA Data and held constant at prompt year value.

(3) PY 2025 ZIA from PRA Data and held constant at prompt year value.

(4) PY 2025 LCR from PRA Data and held constant at prompt year value.

(5-9) Zone 7 resources included in capacity demonstrations sorted by resource type.

(10) LCR position based on demonstrated resources only.

(11) PRMR position based on demonstrated resources only.

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

(13) LCR Position after accounting for undemonstrated Zone 7 Capacity.

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 29

2024 Consumers ELG Annual Report

December 16, 2024 Electronically Submitted via MiEnviro

Ms. Bonnie Broadwater
Michigan Department of Environment, Great Lakes, and Energy
Water Resources Division
350 Ottawa Avenue NW, Unit 10
Grand Rapids, MI 49503-2316

RE: NOTICE OF PLANNED PARTICIPATION
ANNUAL PROGRESS REPORT PURSUANT TO 40 CFR 423.19(g)(3)
CONSUMERS ENERGY COMPANY, JH CAMPBELL COMPLEX NPDES PERMIT NO. MI0001422,
STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES

Dear Ms. Broadwater,

Consumers Energy Company (Consumers) submitted a Notice of Planned Participation (NOPP) for the JH Campbell (Campbell) Complex, NPDES Permit No. MI0001422 on October 11, 2021, seeking to qualify as an electric generating unit that will achieve permanent cessation of coal combustion by December 31, 2028. According to 40 CFR 423.19 (g)(3) annual progress reports shall be submitted detailing the progress made to achieve the cessation of coal use. Consumers is submitting the following information to support the requirements for Campbell Units 1, 2, & 3 that will achieve permanent cessation of coal combustion by December 31, 2028.

Pursuant to 40 CFR 423.19 (g)(4), an annual progress report shall detail the completion of any interim milestones listed in the NOPP since the previous progress report, provide a narrative discussion of any completed, missed, or delayed milestones, and provide updated milestones. An updated timeline, to reflect the requirements of 40 CFR 423.19(f)(4), is included in Attachment A. A copy of the official retirement filing as required under 40 CFR 423.19(f)(4)(ii), is included in Attachment B.

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

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true,

Consumers Energy
1945 W. Parnall Road
Jackson, MI 49201
www.consumersenergy.com

accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

Sincerely,

Nathan J. Hoffman
Consumers Energy
Executive Director of Fossil Generation

Electronically Distributed

CC: Ms. Rachel Proctor, Consumers Energy Company
Ms. Kristin Melcher, Consumers Energy Company, Campbell

Attachment A
Permanent Cessation Timeline Update

ACTIVITY – INTERIM MILESTONE	PROJECTED DATE OF COMPLETION	STATUS	NOTES
NOPP Submittal	10/13/2021	COMPLETE	
Expected Integrated Resource Plan (IRP) Approval by the MPSC	6/27/2022	COMPLETE	12/16/2022: The IRP was approved on June 23, 2022. A copy of the most recent integrated resource plan for which the applicable state agency approved the retirement of the unit subject to the Effluent Limitation Guidelines (ELGs), pursuant to 40 CFR 423.19(f)(2), was included as **Attachment B** in the 2022 Annual Progress Report.
Expected MISO Study Results	3/11/2022	COMPLETE	12/15/2023: MISO approved the suspension of Campbell Units 1, 2, & 3 effective June 1, 2025, on March 11, 2022
Cold & Dark[1] Outage Specifications Finalized	~~4/22/2024~~ 7/18/2024	COMPLETE	12/16/2022: Cold and Dark outage specifications are delayed; however, the delay in these final specifications will not impact Campbell Units 1, 2, and 3 retirement schedule, which are still expected to retire in 2025 consistent with the NOPP. The delay is due to the difference between the initial conceptual schedule and the refined project schedule.

ACTIVITY – INTERIM MILESTONE	PROJECTED DATE OF COMPLETION	STATUS	NOTES
Cold & Dark Contract Award	~~1/26/2025~~ 12/19/2024	ON SCHEDULE	12/16/2022: Change in date is due to the difference between the initial conceptual schedule and the refined project schedule.
MPSC[2] and MISO[3] approved Unit 1, 2, & 3 Retirement; Cold & Dark Outage Start	~~5/31/2025~~ 6/1/2025	ON SCHEDULE	12/10/2024: Suspension of Campbell Units 1,2 & 3, effective June 1, 2025. See **Attachment B.** 10/11/2021: 5/31/2025 is the expected date that JH Campbell Units 1, 2, and 3 will no longer generate electricity
Cold & Dark Outage Complete	~~9/6/2025~~ ~~8/31/2025~~ 10/31/2025	ON SCHEDULE	12/14/2023: The change in date will not impact Campbell Units 1, 2, and 3 retirement schedule. 10/11/2021: JH Campbell Units 1, 2, and 3 will be deenergized and ready for AD&D. The change in date is due to the difference between the initial conceptual schedule and the refined project schedule.

Notes:
(1) "Cold & Dark" refers to a period of time where preparations are put in place for Abatement, Decommissioning & Demolition (AD&D).
(2) MPSC is the Michigan Public Service Commission
(3) MISO is the Midcontinent Independent System Operator

Attachment B
Official Filing Pursuant to §423.19(g)(4)(ii)

Consumers Energy
Count on Us®

A CMS Energy Company

Timothy J. Sparks, P.E.
Vice President Electric Grid Integration

VIA Electronic Mail

December 14,2021

Andrew Witmeier
Director of Resource Utilization
Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, IN 46032

Re: Suspension of Campbell Units 1, 2 & 3

Dear Mr. Witmeier:

Consumers Energy Company ("Company") hereby provides notice to the Midcontinent Independent System Operator, Inc. ("MISO") that it intends to suspend Campbell Units 1, 2 and 3 effective June 1, 2025. Attached is the notice of such intent in accordance with Section 38.2.7 and Attachment Y of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

Campbell Unit 3 is jointly owned by the Company (93.3%), CPNode CONS.CAMPBELL3, Michigan Public Power Agency (4.8%), CPNode CONS.CA3.MPPA, and Wolverine Power Supply Cooperative (1.9%), CPNode CONS.CA3_WPSC. The Company attests that, pursuant to the relevant Operating Agreements, it is authorized to submit this Attachment Y notice on behalf of all Campbell Unit 3 owners.

In the event you have any questions regarding this matter, please contact Kathy Wetzel at (517) 788-2039.

Regards,

Timothy J. Sparks
Vice President Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Cc: Kathy Wetzel
Thomas Clark

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic copy of the completed form will be accepted by the Transmission Provider, however, a form will not be considered complete until the original form containing an original signature, including all attachments, is received by the Transmission Provider at the following address: MISO, Attention: Director of Transmission Planning; 720 City Center Drive, Carmel, IN 46032.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:
Consumers Energy Company (see attached letter re: Campbell Unit 3)

Name of Market Participant: Consumers Energy Company - NERC ID: CETR

Owner's state of organization or incorporation Michigan

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] Campbell Units 1, 2 & 3

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] CAMPBELL UNITS 1+2: UMBRELLA GIA BETWEEN CONSUMERS, METC + MISO FERC DOCKET ER21-999. CAMPBELL UNIT 3: FERC DOCKET ER06-1441 FOR MISO SERVICE AGREEMENT NO. 1755

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[X] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on 1st [day] of June [month] of 2025 [year]

[ ] Rescind the current notice to SuspendThe facility is further described as follows:

Location: West Olive, Michigan

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
Campbell Unit 1	CONS.CAMPBELL1	260	260
Campbell Unit 2	CONS.CAMPBELL2	360	360
Campbell Unit 3	CONS.CAMPBELL3	844	844

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

Signature

Name: TIMOTHY J SPARKS

Title: VP ELECTRIC GRID INTEGRATION

Date:

Contact Information

Email: TIMOTHY.SPARKS@CMSENERGY.COM

Phone: 517 788 1053

Andrew Witmeier
Director, Resource Utilization
317-249-5585
awitmeier@misoenergy.org

VIA OVERNIGHT DELIVERY

March 11, 2022

Timothy J. Sparks
Vice President, Electric Grid Integration
Consumers Energy Company
1945 W. Parnall Rd.
Jackson, MI 49201

Subject: **Approval of Campbell Units 1,2 &3 Attachment Y Suspension Notice**

Dear Mr. Sparks,

On December 14, 2021, Consumers Energy Company submitted an Attachment Y Notice to MISO for the suspension of Campbell Units 1,2 & 3, effective June 1, 2025. After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the suspension of Campbell Units 1,2 & 3 would not result in violations of applicable reliability criteria. Therefore, Campbell Units 1,2 & 3 may suspend without the need for the generators to be designated as a System Support Resource ("SSR") units as defined in the Tariff.

As there were no reliability criteria violations, MISO will continue to preserve the confidentiality of the Attachment Y Notice.

Please do not hesitate to contact me if you have any questions regarding this matter.

Respectfully,

Andrew Witmeier
Director, Resource Utilization

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-26-16

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

Exhibit 30

DOE Rehearing Procedures

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the

issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

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