BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 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 **

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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:

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On behalf of Consumers Energy Company

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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. 202-25-7

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

Filed September 5, 2025

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. 202-25-7

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

Filed September 5, 2025

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

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CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on 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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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?

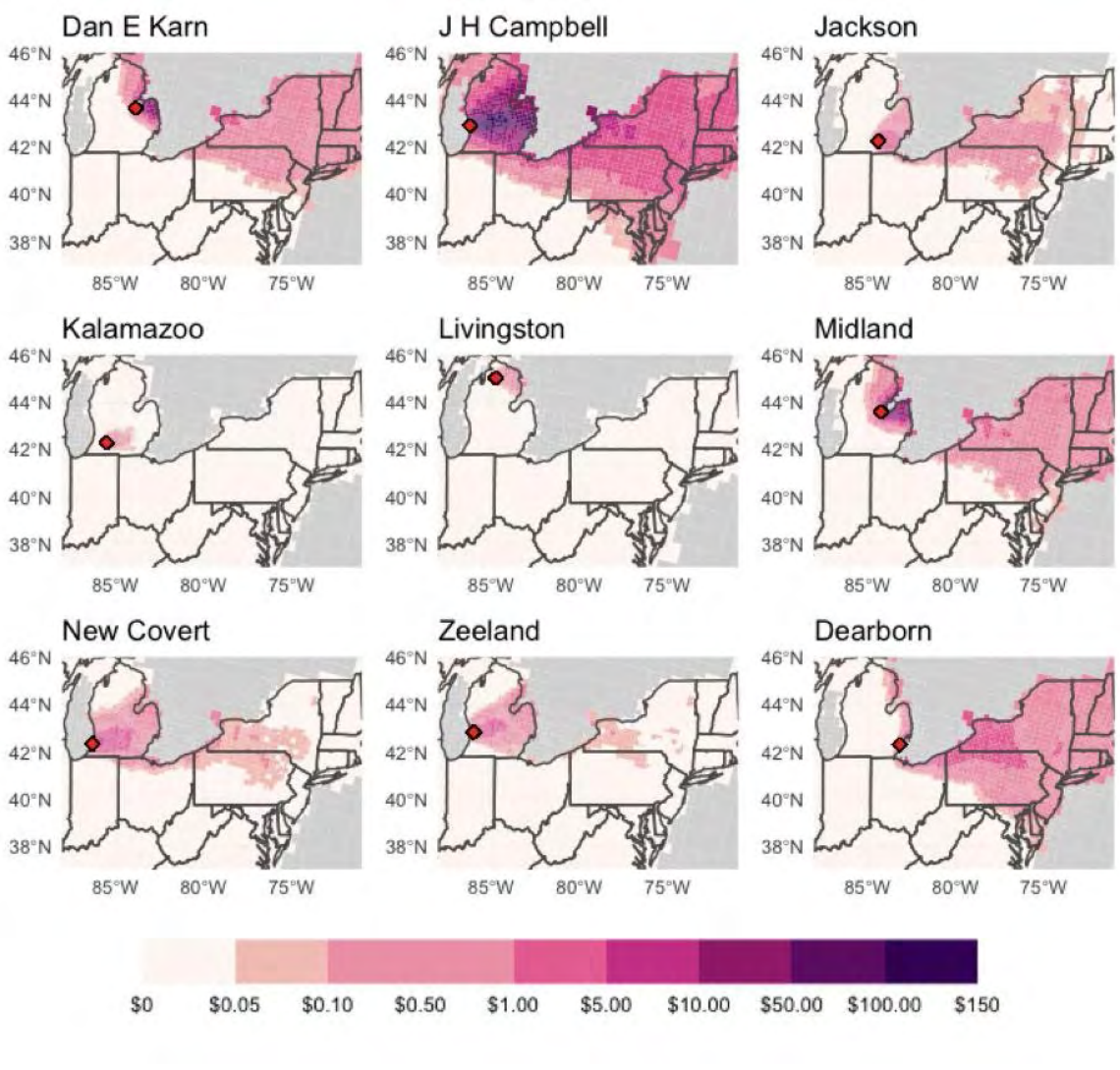
A: Operating Dearborn, Covert, Kalamazoo, and Livingston, the gas plants Consumers plans to purchase, at current levels, contributes to 9-19 premature mortalities per year and costs $93-209 million per year. Dearborn has the highest total health impacts of these four plants (7.5-17 mortalities per year) 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

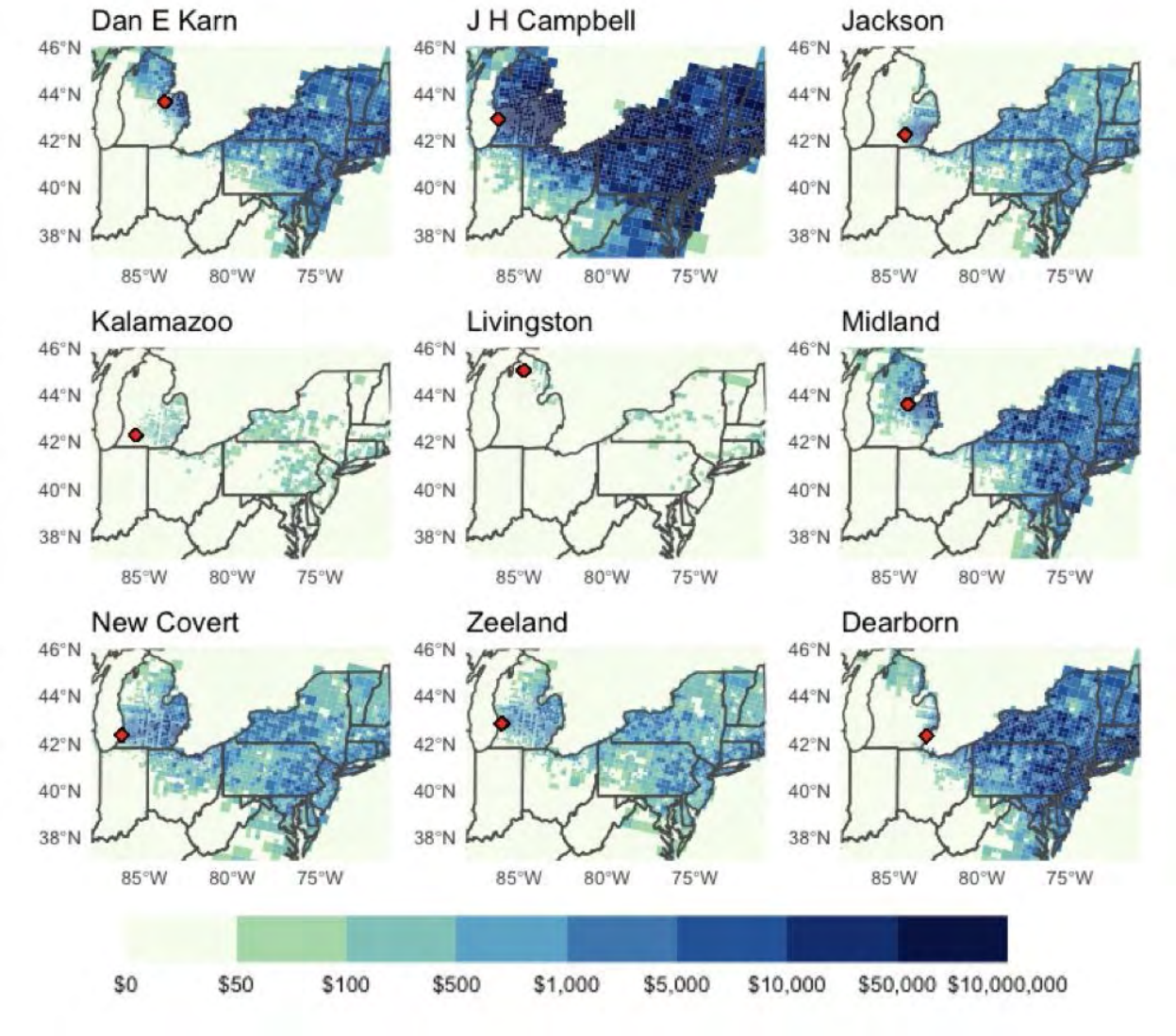
are normalized by population (e.g., $ per 100 people), so the health impacts scale with changes in atmospheric $PM_{2.5}$. The largest per-capita health impacts are near and directly downwind of the plants, because that is where the emissions from each plant impact air quality the most. However, $PM_{2.5}$ 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. 202-25-7

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

Filed September 5, 2025

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. 202-25-7

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

Filed September 5, 2025

Exhibit 25

2026 Consumers Energy Capacity Demonstration

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Theresa A.G. Staley
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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.

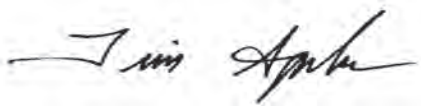
18. Forward ZRC Contracts

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)

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Garrick J. Rochow,
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Jackson, Michigan

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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.

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Garrick J. Rochow,
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Jackson, Michigan

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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)

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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

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 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.

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 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

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

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and after January 1, 2022

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dated December 22, 2021
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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,
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-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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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

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

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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Consumers Energy Company
(To revise price)

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)

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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)

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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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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

Effective for service rendered on
and after November 15, 2019

Issued under authority of the
Michigan Public Service Commission
dated November 14, 2019
in Case No. U-18249

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

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-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 **First Revised Sheet No. D-92.00**
Consumers Energy Company **Cancels Original Sheet No. D-92.00**
(To revise Streetlighting Outage Credit language)

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)

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

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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

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-94.30
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. 202-25-7

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

Filed September 5, 2025

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.

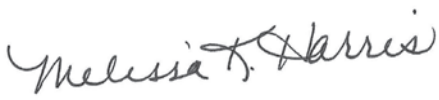
19. Planning Resource Auction Purchases

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

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Utility: Consumers Energy Company
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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
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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											
37											
38											
39											
40											
41											
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
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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
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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
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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
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EXHIBIT 8
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EXHIBIT 9
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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)

Fourth Revised Sheet No. D-72.00
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. 202-25-7

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

Filed September 5, 2025

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
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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
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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
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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
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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
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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
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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
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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

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Exhibit: 7
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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
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Exhibit: 1
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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

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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

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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
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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
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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
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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

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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

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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

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Date: February 24, 2025
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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
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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)

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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)

Issued March 22, 2024 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 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-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)

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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-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)

Issued August 30, 2024 by
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M.P.S.C. No. 14 – Electric
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
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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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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)

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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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)

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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)

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 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)

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-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)

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)

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

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 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)

Issued March 22, 2024 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 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
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on and after March 18, 2022

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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)

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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. 202-25-7

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

Filed September 5, 2025

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).

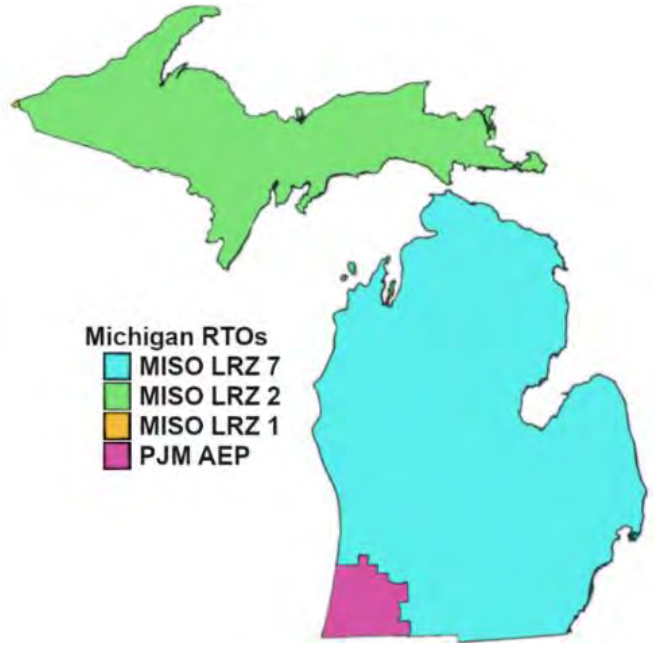
[10] See January 23, 2025 Order in Case No. U-21571

[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. 202-25-7

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

Filed September 5, 2025

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. 202-25-7

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

Filed September 5, 2025

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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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 31

MISO 2025–26 Auction Results

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

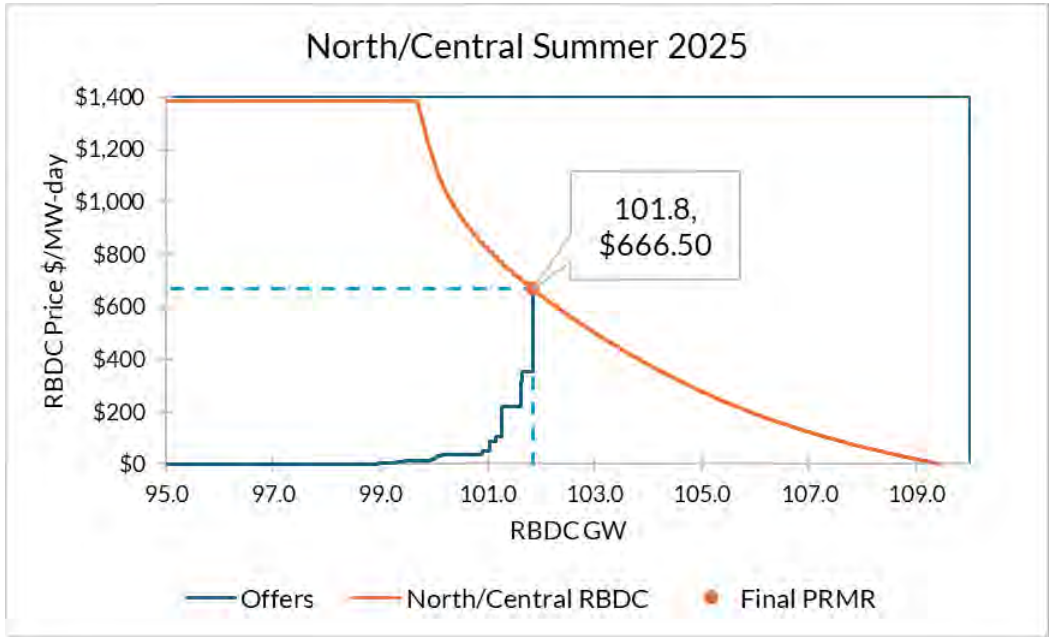
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

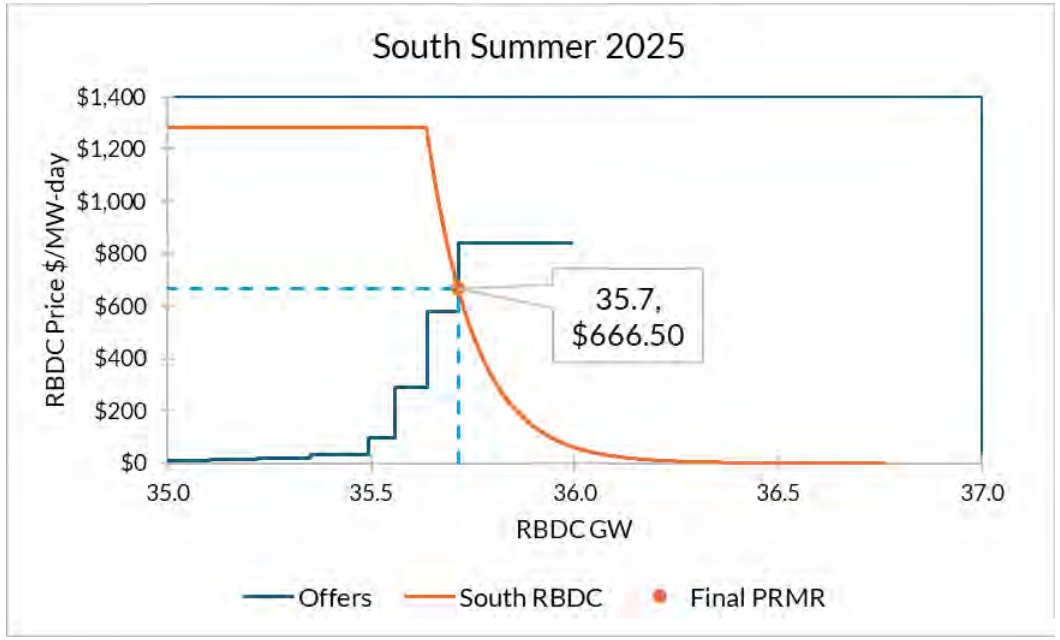
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

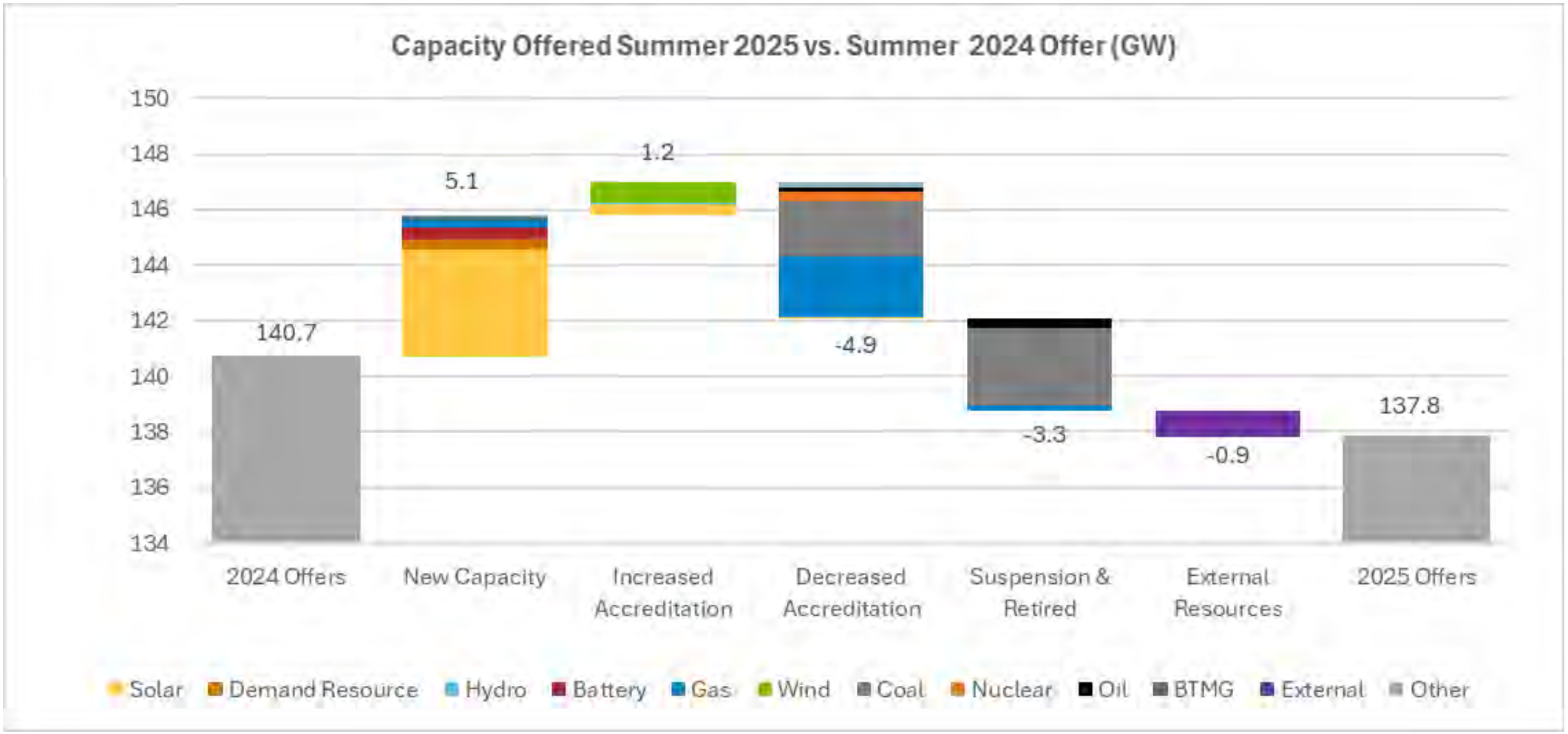
MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88 ***Annualized*** **$217** (North/Central) **$212** (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

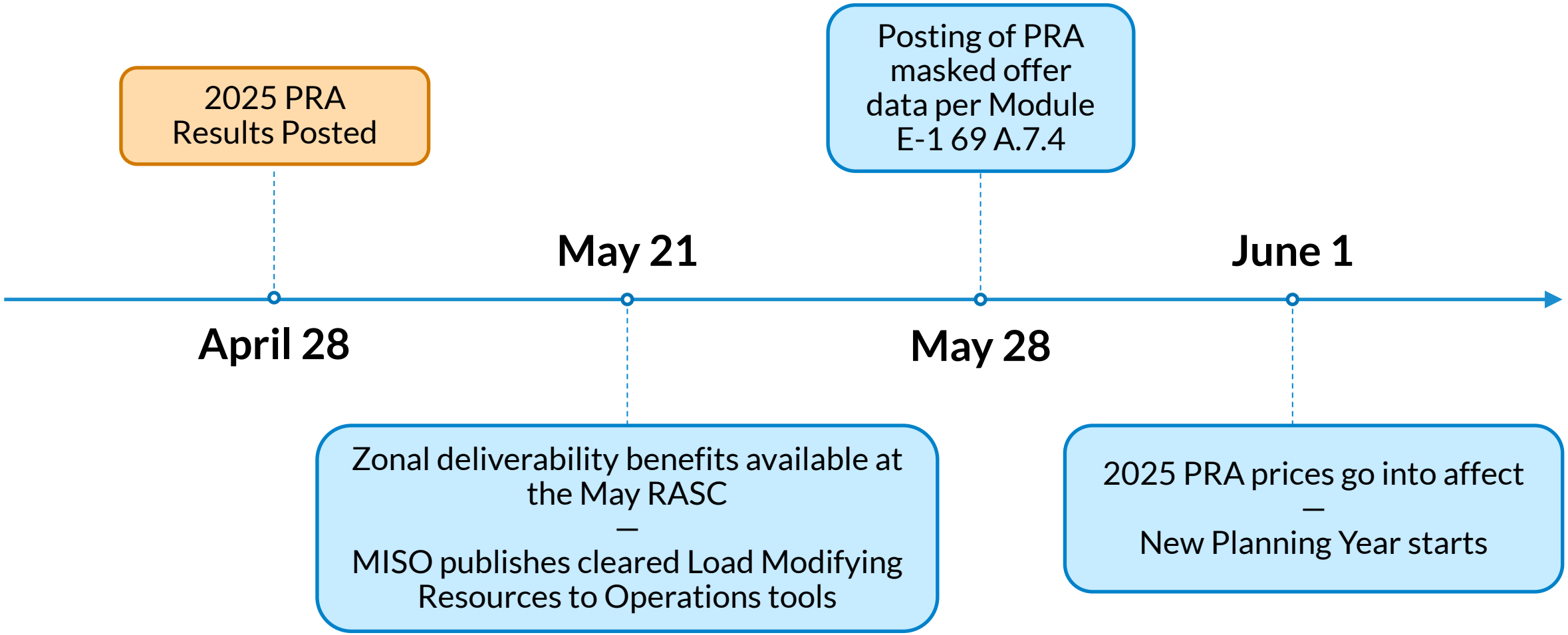
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Next Steps


2025 PRA Results Posted
April 28
May 21
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
Posting of PRA masked offer data per Module E-1 69 A.7.4
May 28
June 1
2025 PRA prices go into affect
—
New Planning Year starts

Appendix

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Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

UCAP: Unforced Capacity

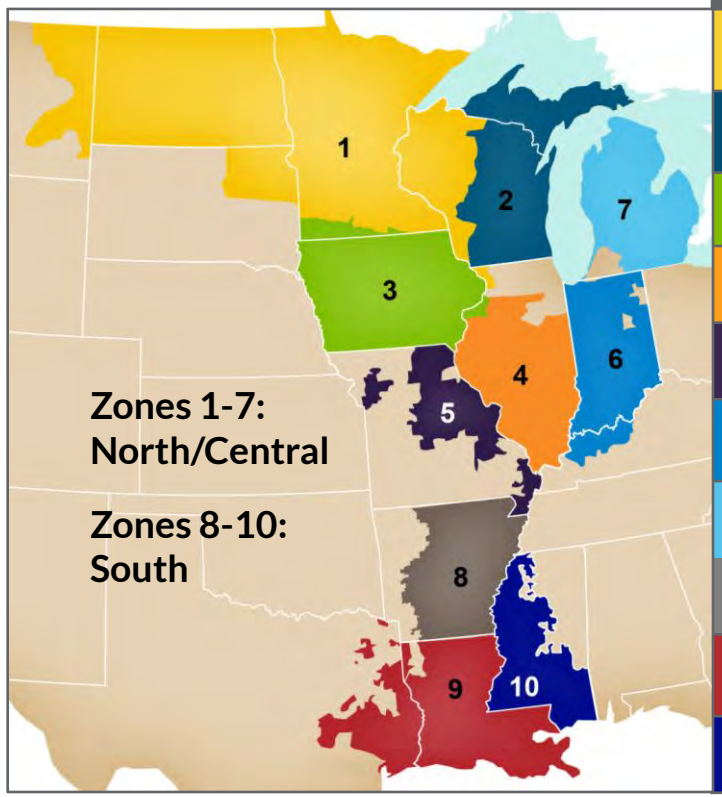
ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

2025 PRA Results

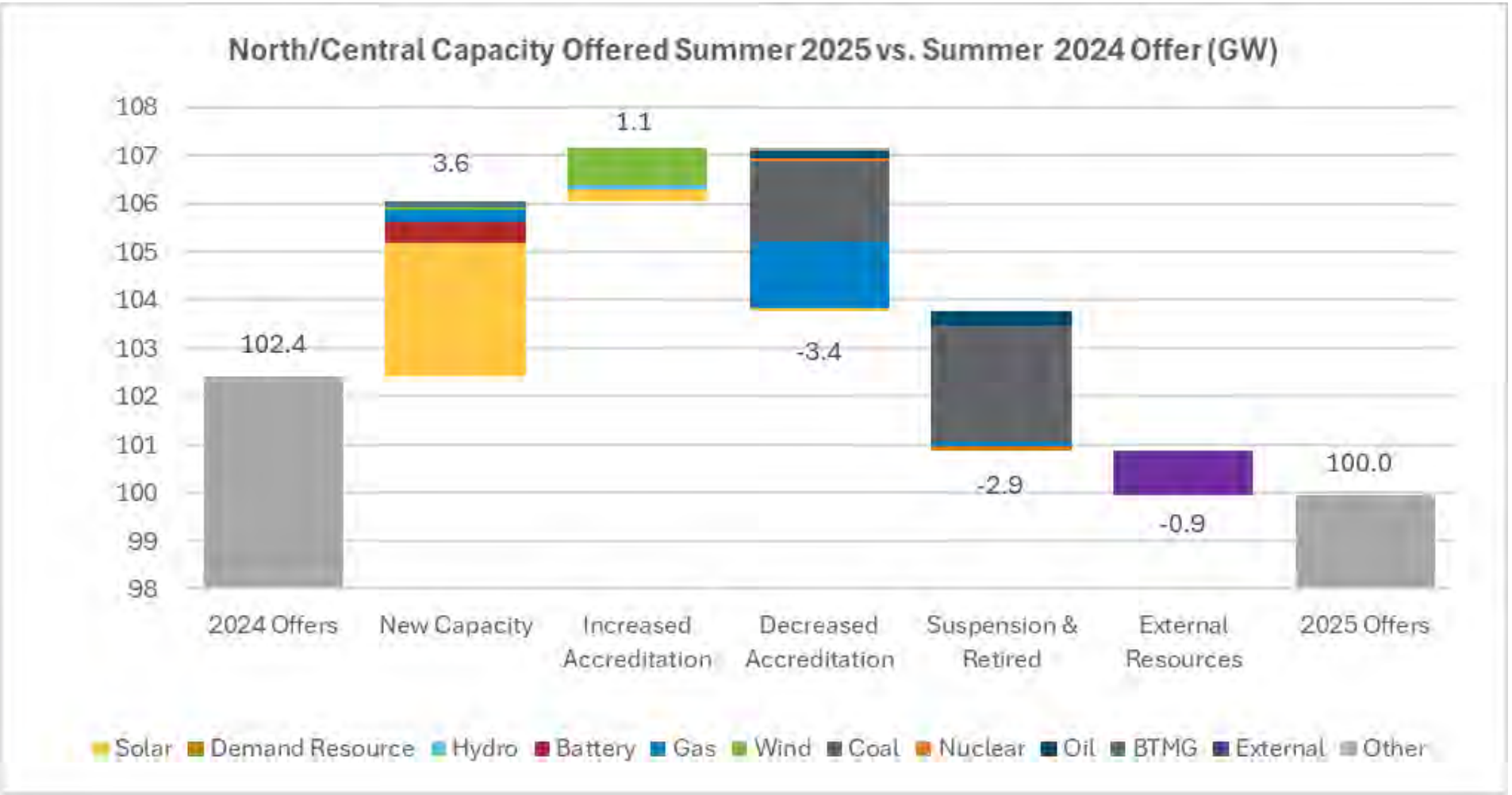
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

Annualized
$217 (North/Central)
$212 (South)

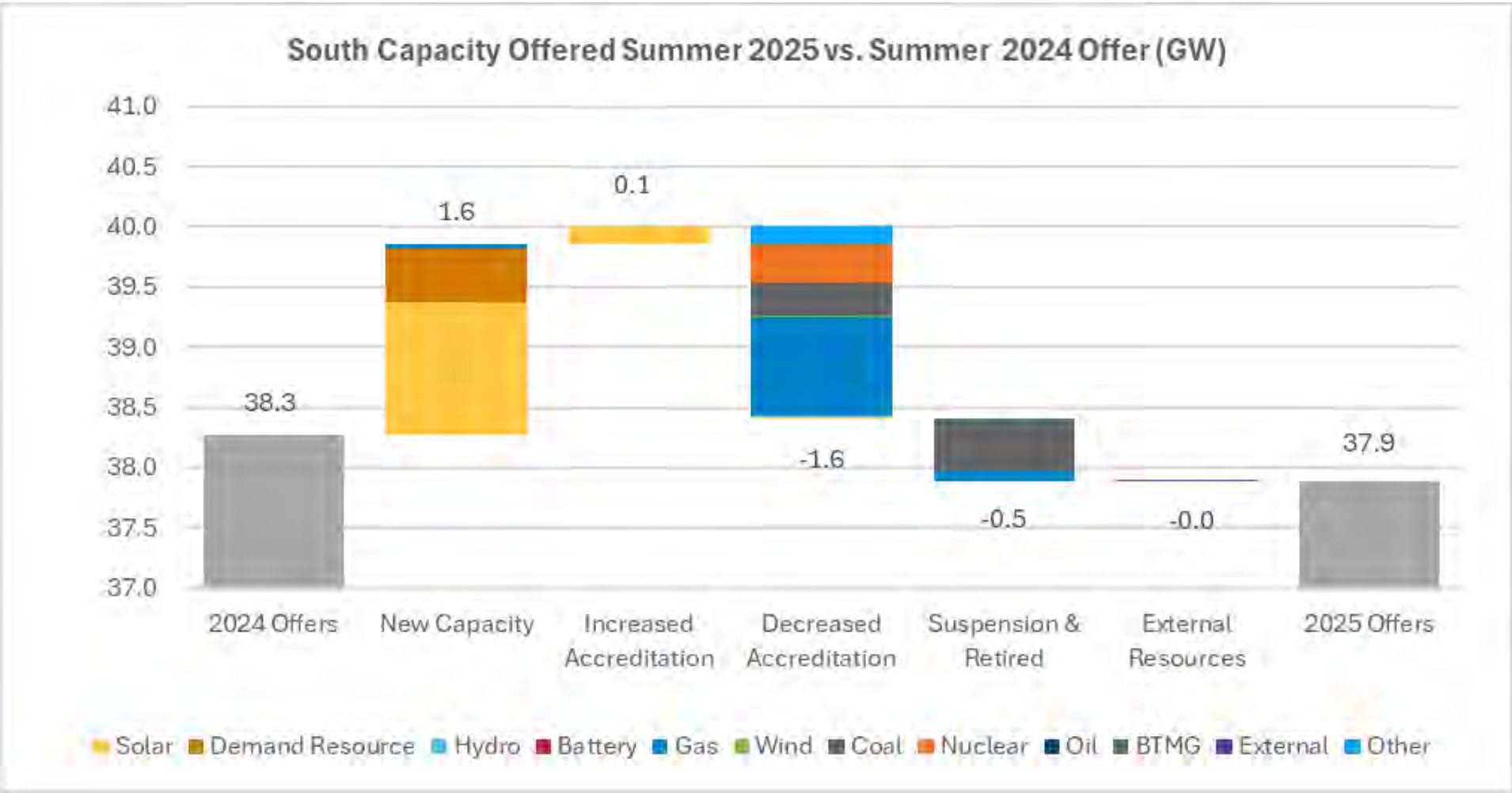
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

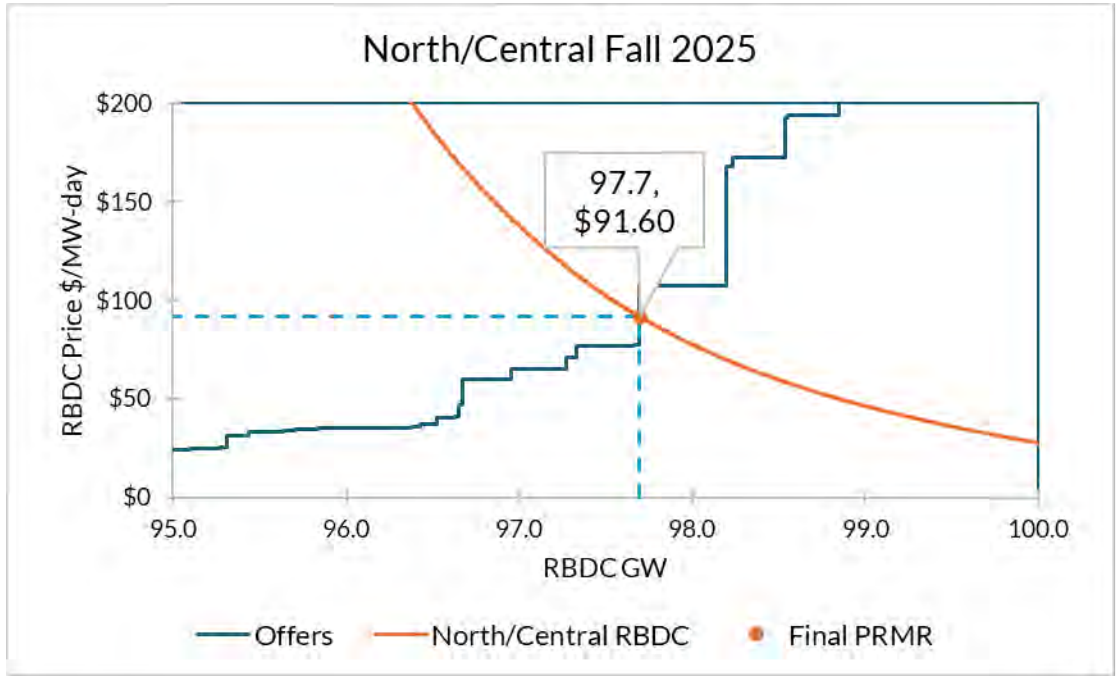
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

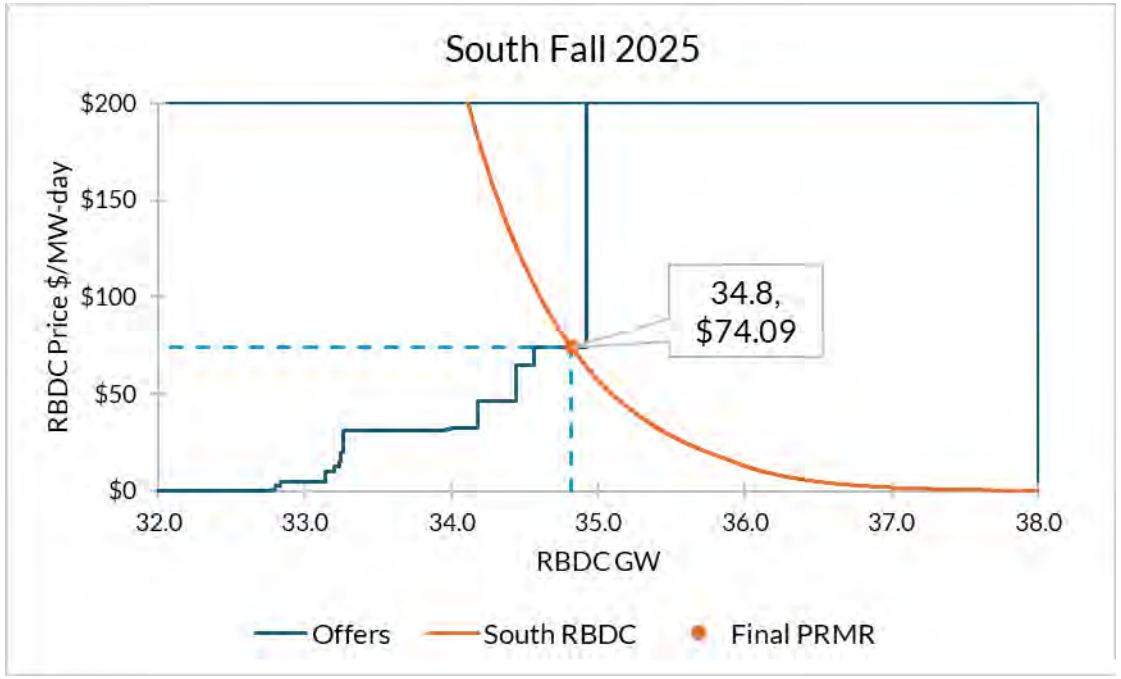
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

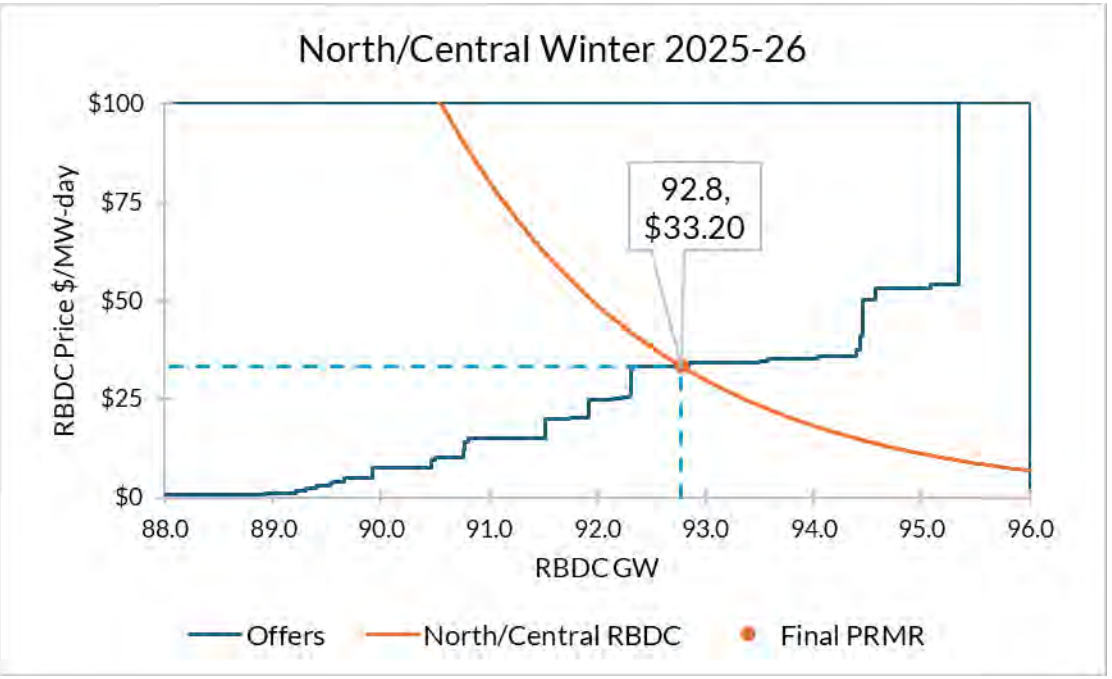
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

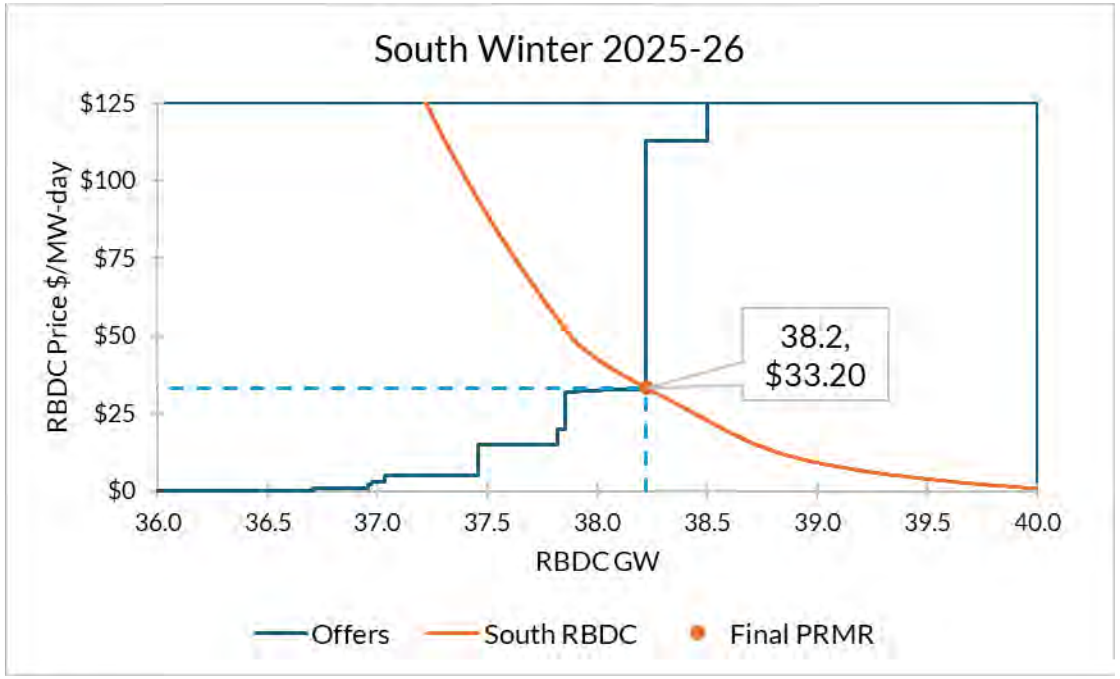




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal resource in the South sets the price in that subregion
- In fall season, "effective" margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

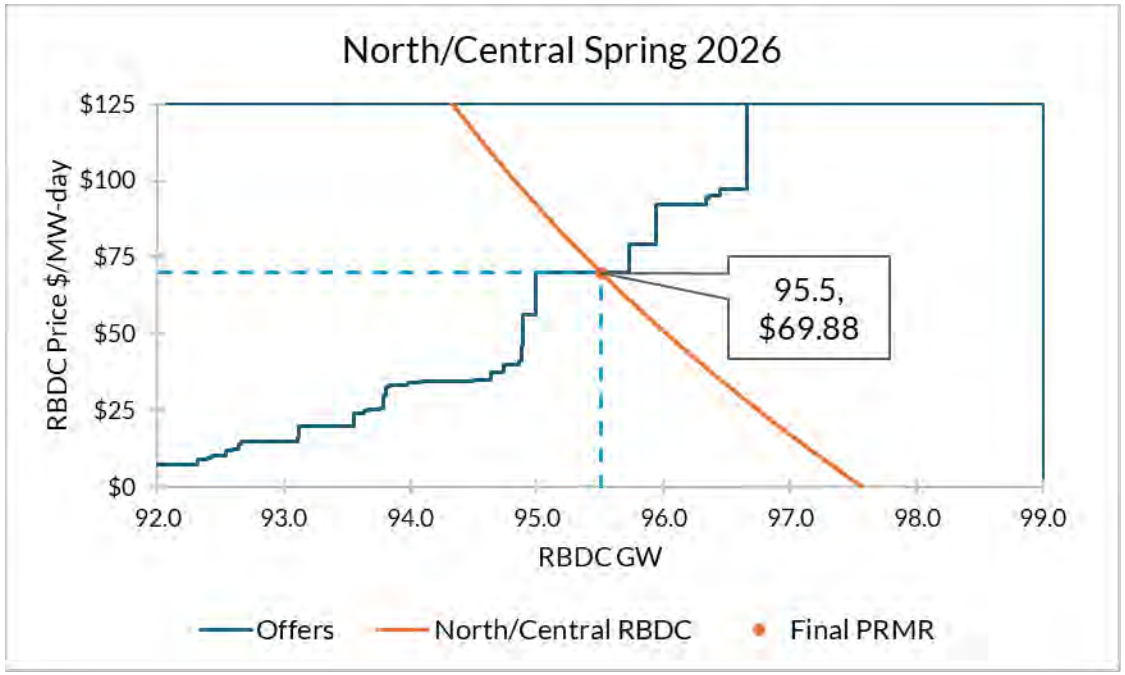
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

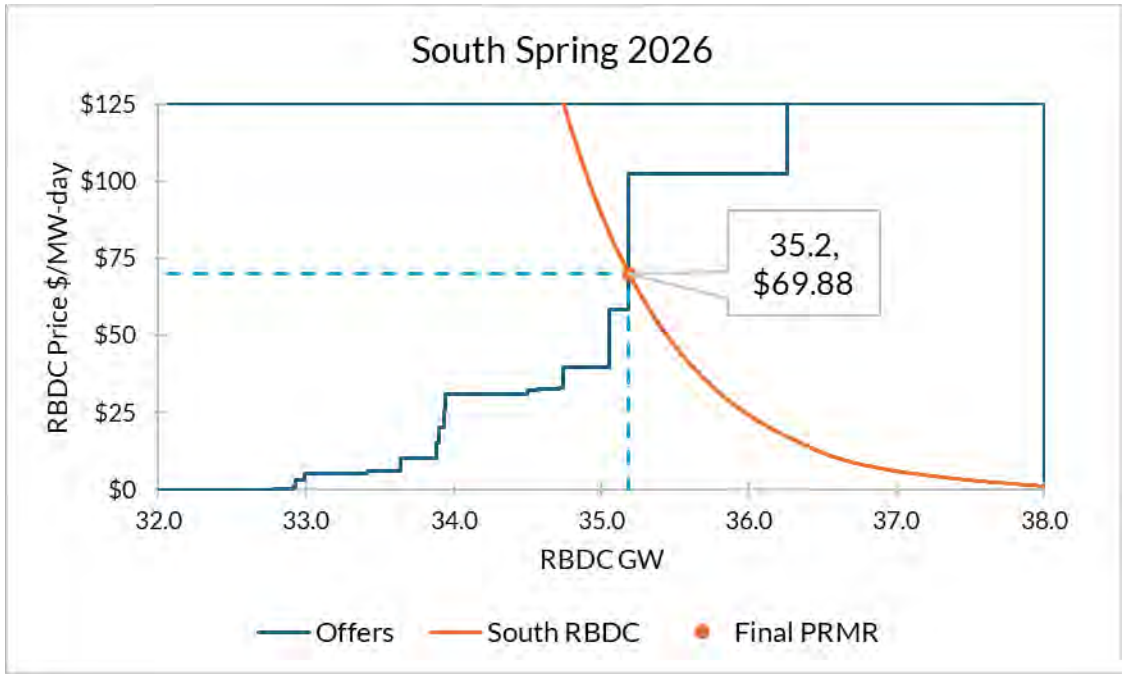




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Summer 2023**	**Summer 2024**	**Summer 2025**	**Summer 2023**	**Summer 2024**	**Summer 2025**
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										
Summer 2025	$666.50										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)

Cleared Capacity, Imports & Exports (MW)

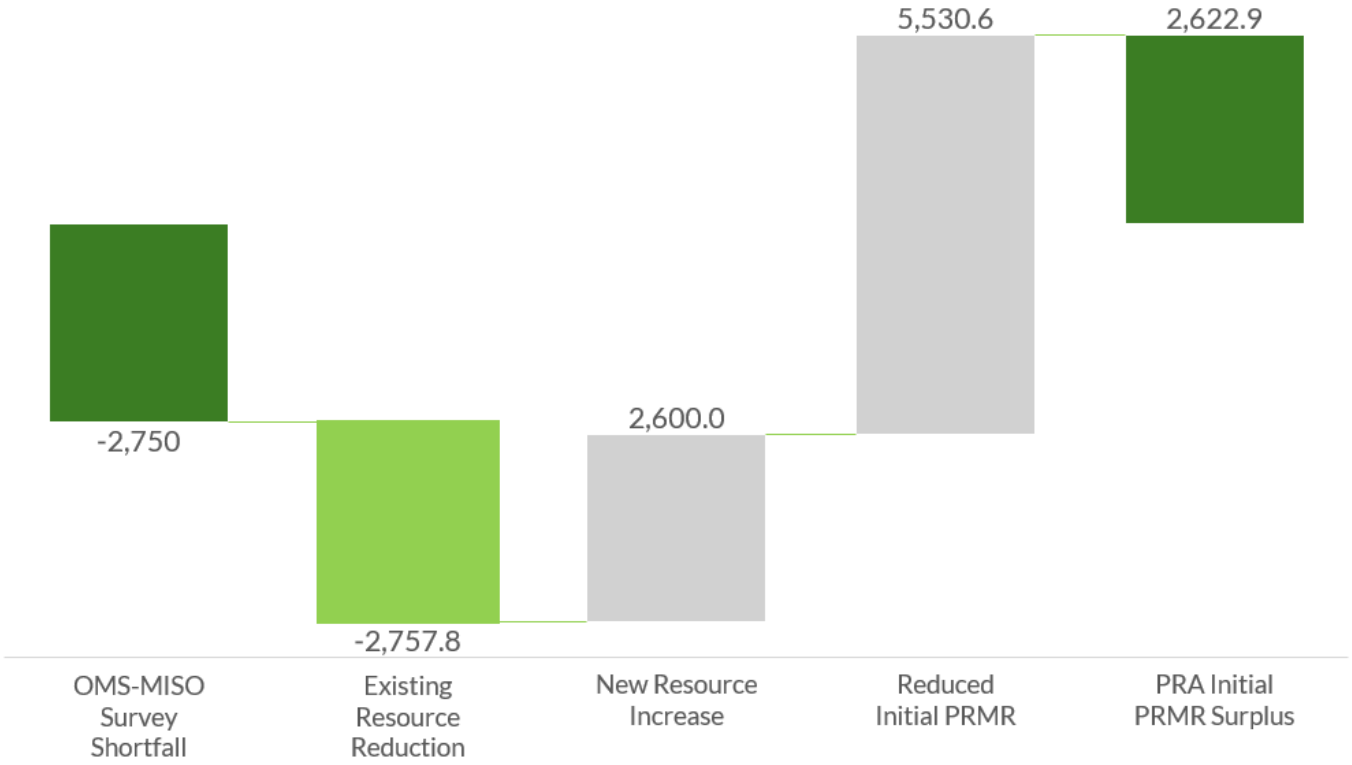
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs.
2025 PRA Actual PRMR Surplus (MW)

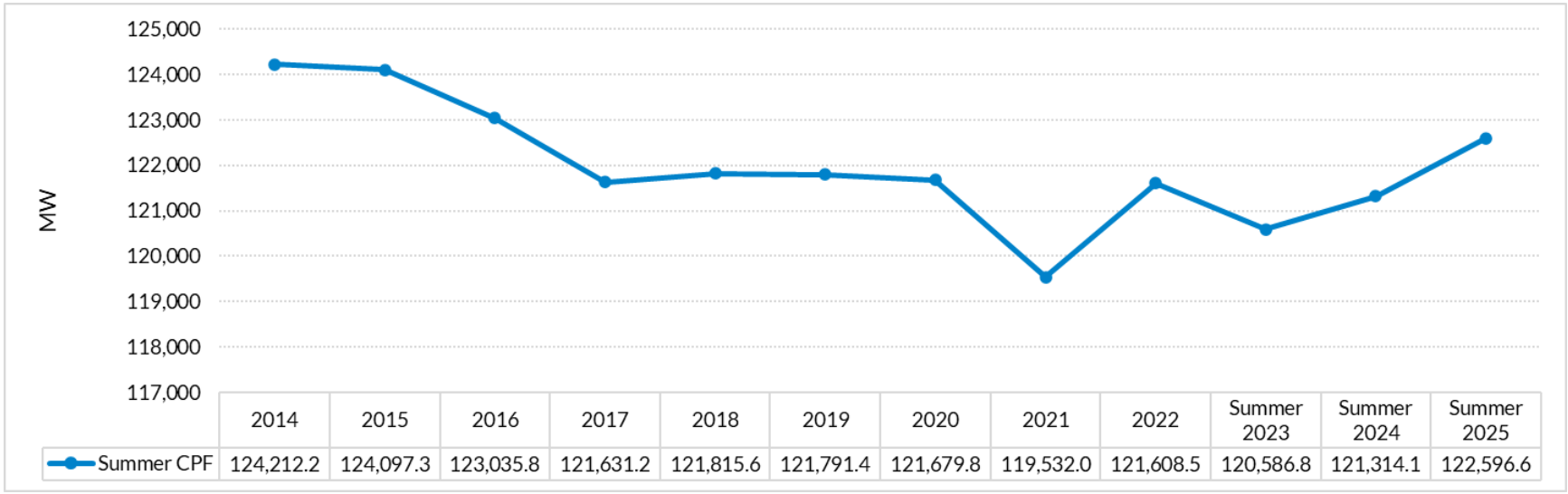


*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

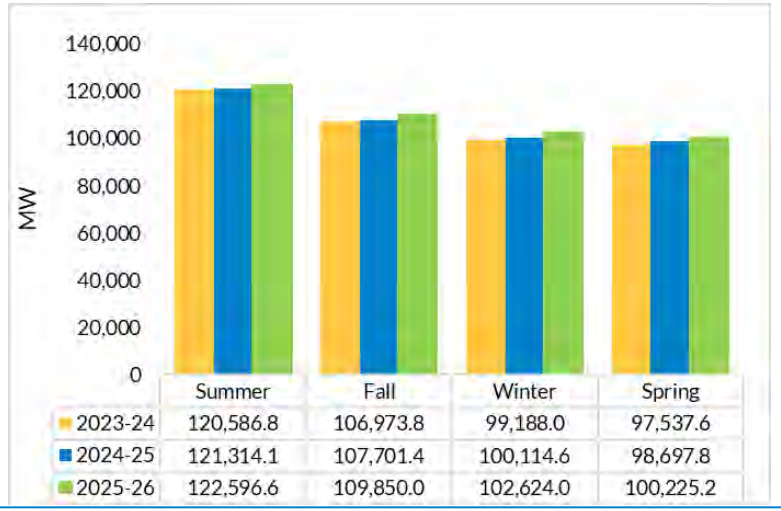
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6

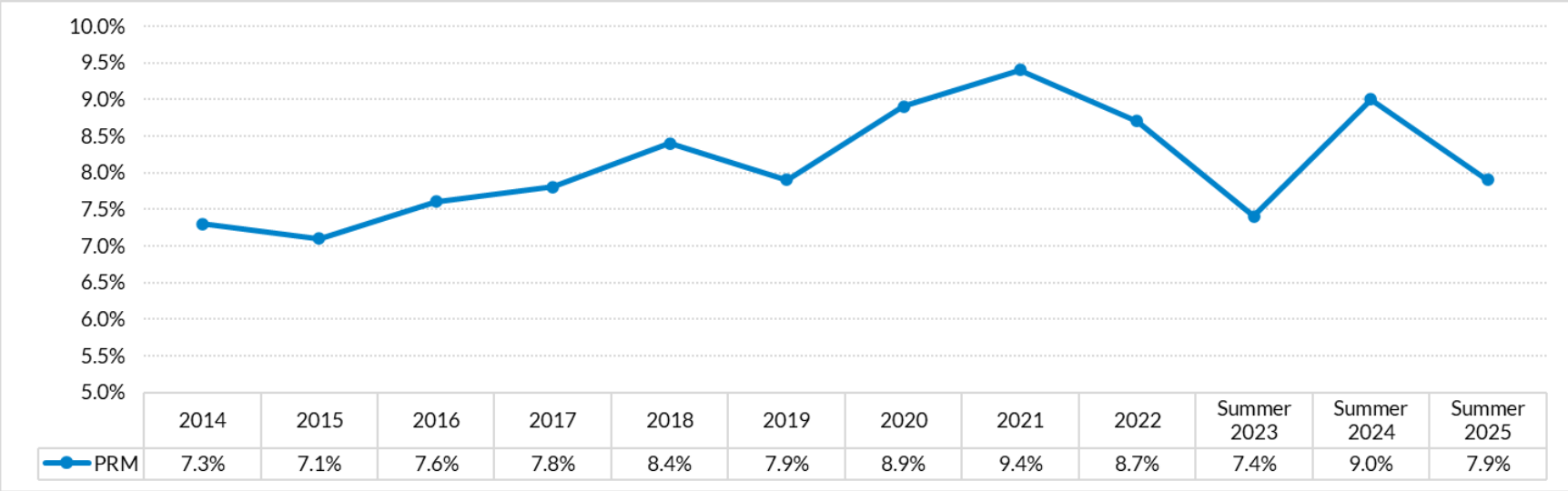


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

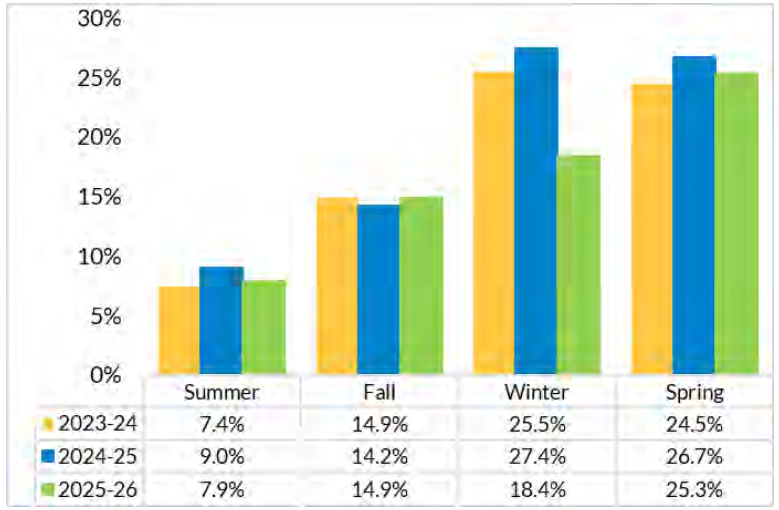
PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Planning Reserve Margin (%)

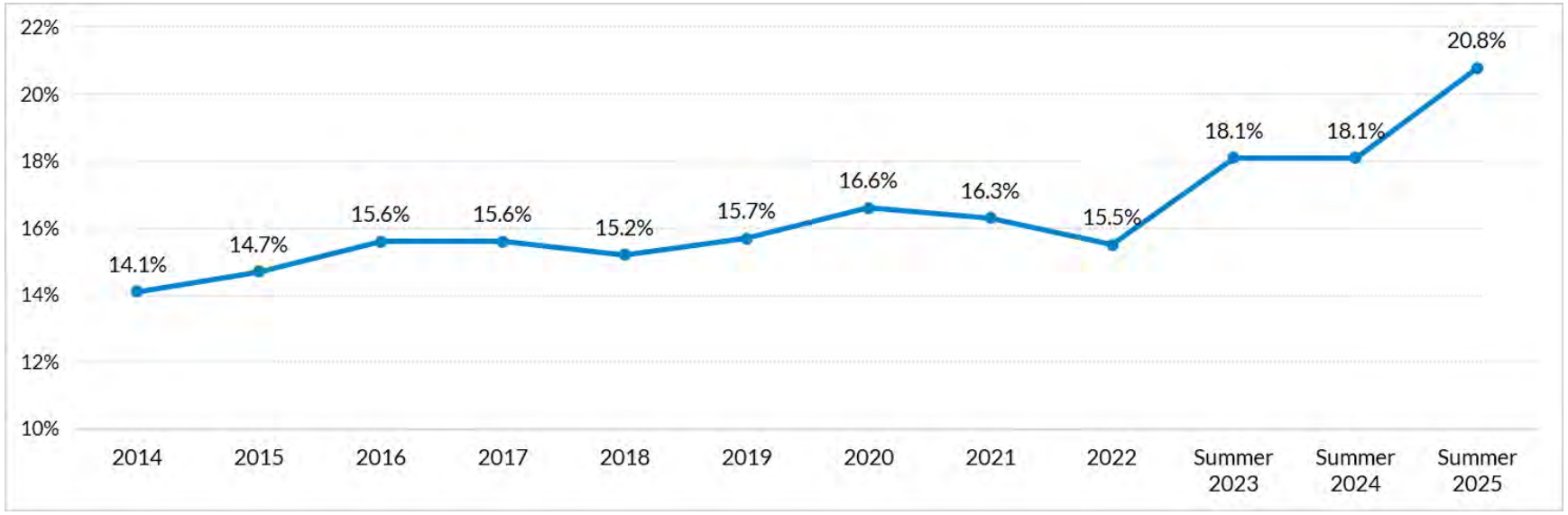


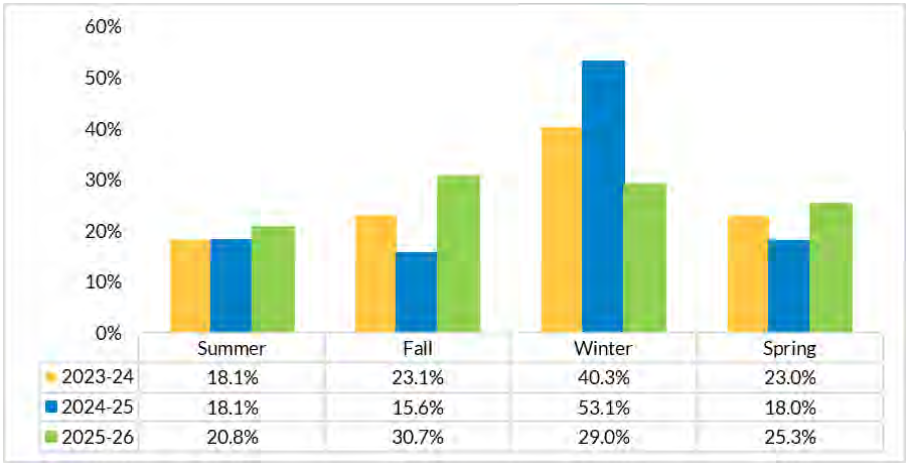
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)

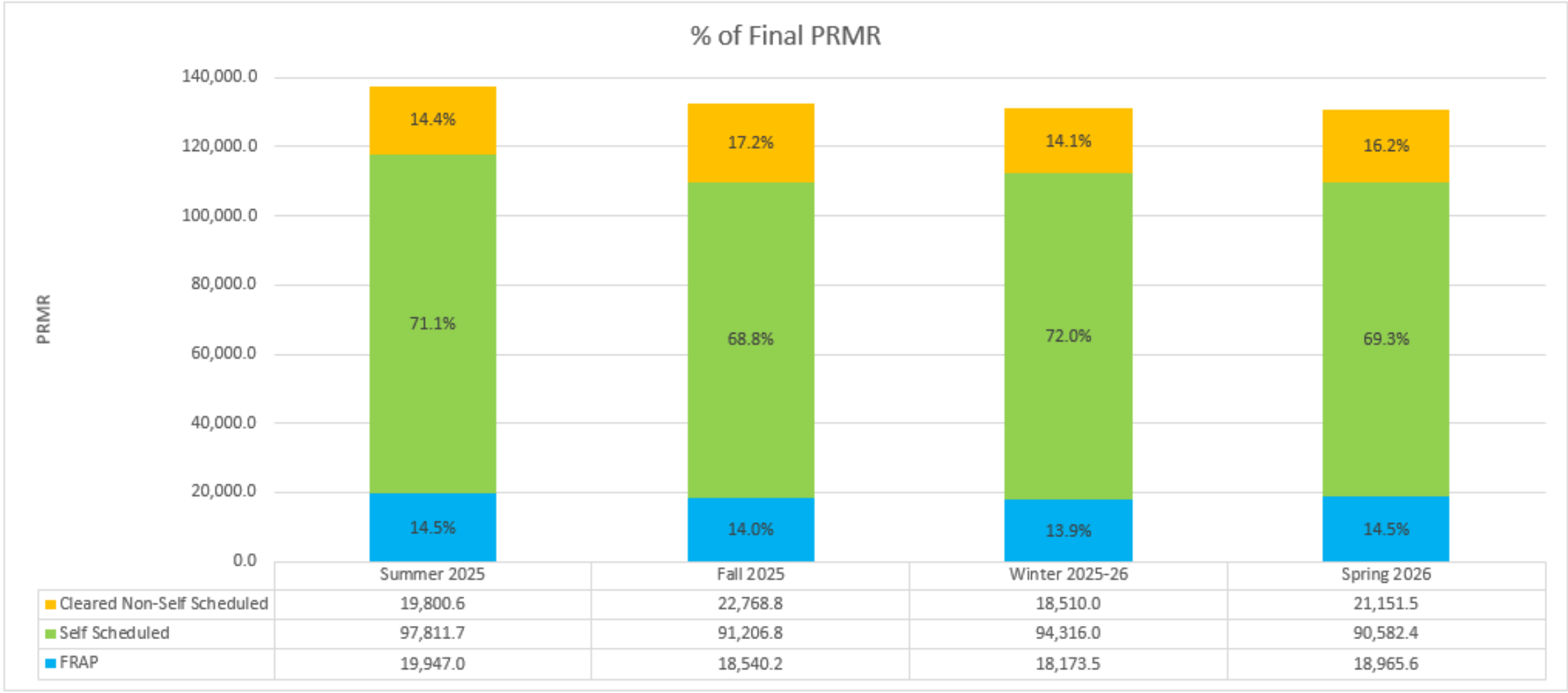




- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

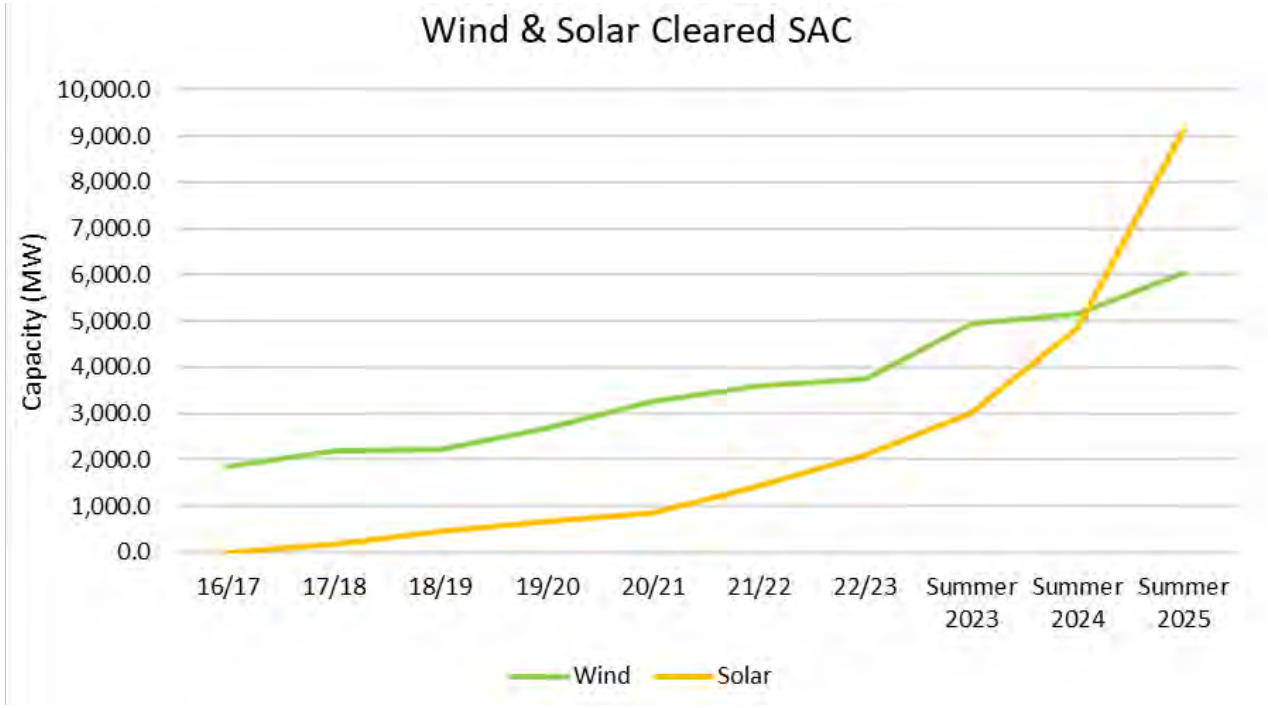


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

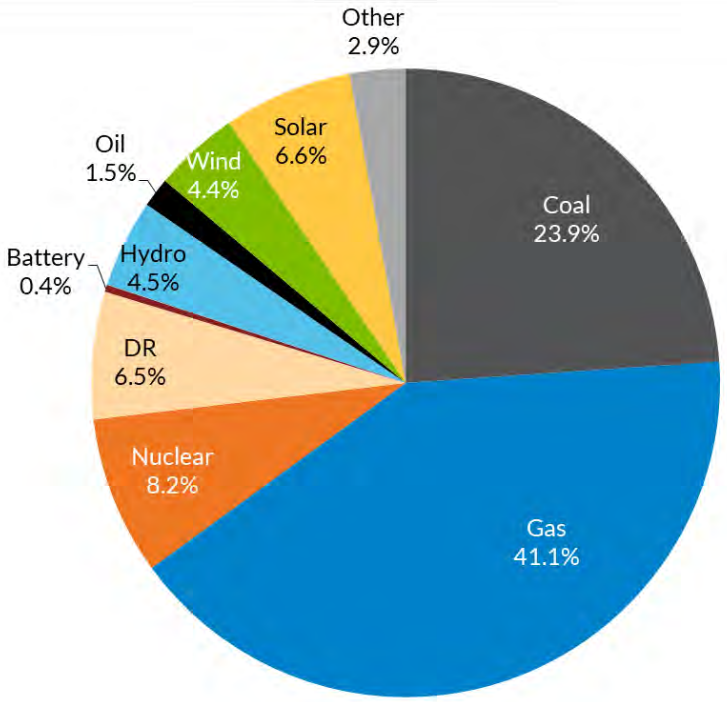
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

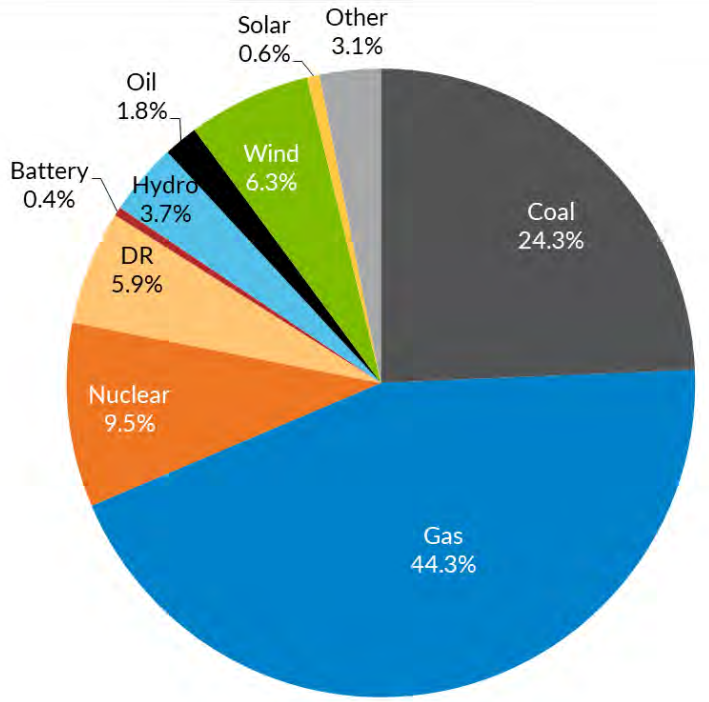
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

Winter 2025/26

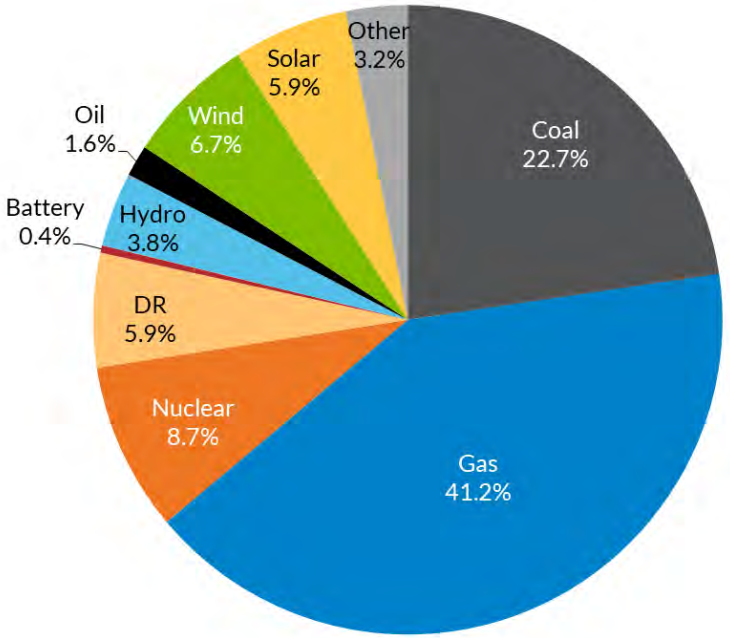


PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

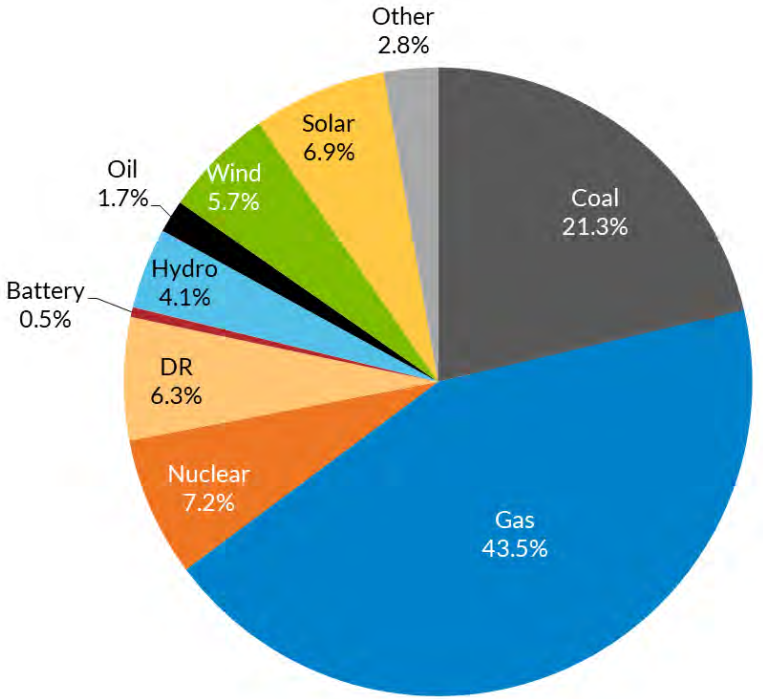
Fall 2025



MISO-Wide

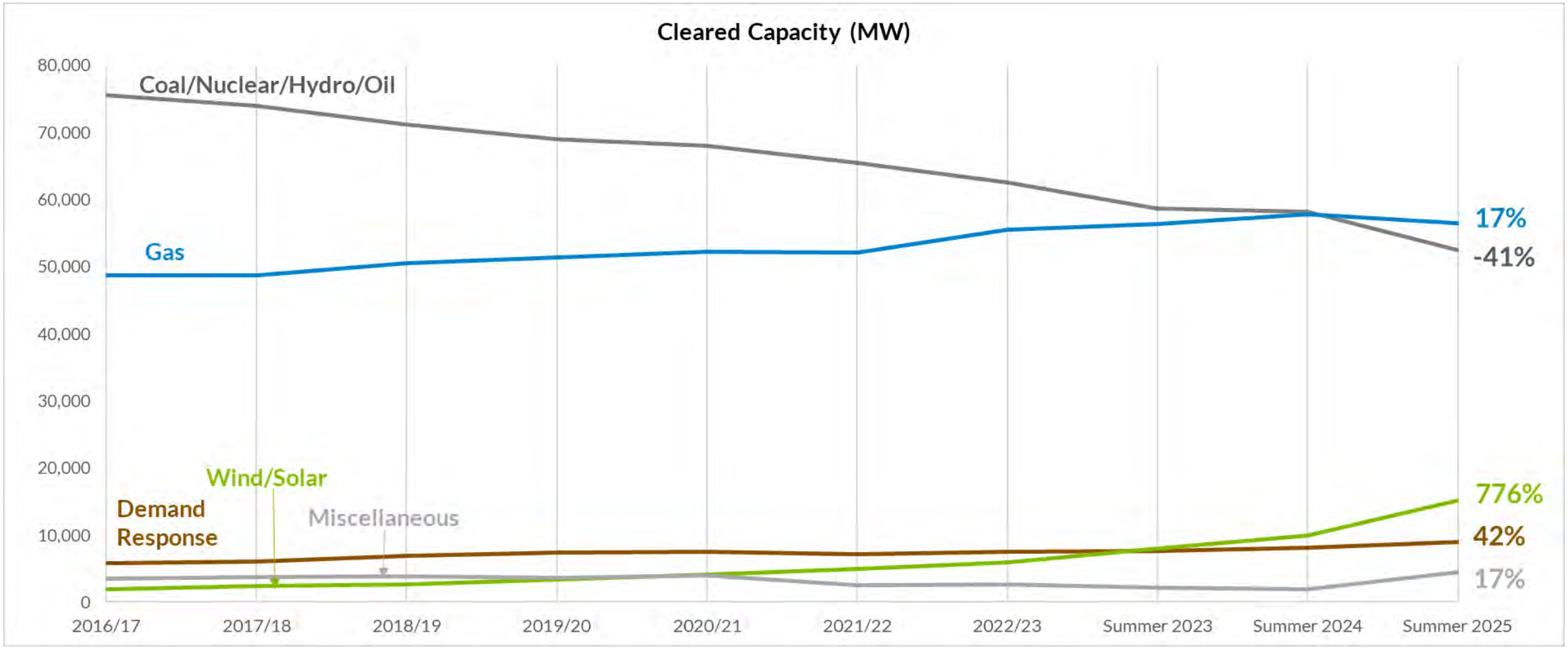
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026



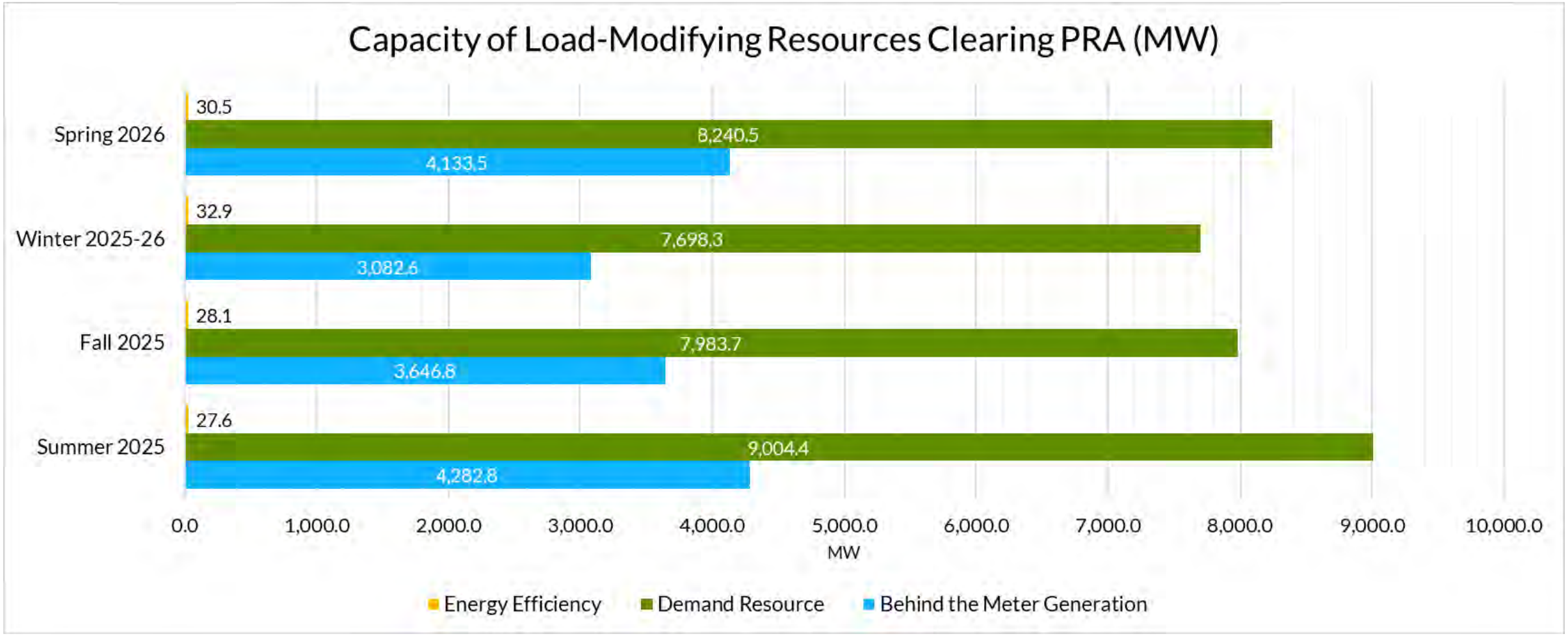
PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 32

MISO Emergency Declarations

Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

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Maximum Generation Emergency Declarations

through June 2024

(Updated 08/30/2024)

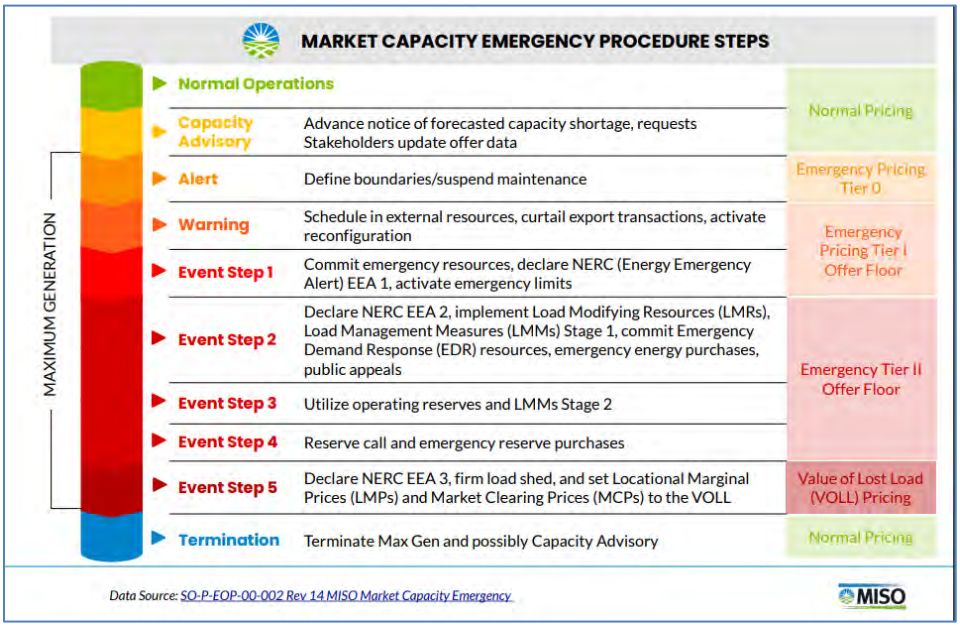

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send MCS Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/ LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/ DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

- **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
- **Max Gen Alert** - Provides an early alert that system conditions may require the use of MISO's generation Emergency procedures.
- **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.
- **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources

Maximum Generation Emergency Declarations
through June 2024
(Updated 08/30/2024)

2009

- 01/13/2009 18:00 – 20:30 EST – West Region Maximum Generation Emergency **ALERT** The reason for the Alert is cold temperatures and generation loss.

2010

- 08/11/2010 14:00 – 20:00 EST – Sub-Area Maximum Generation Emergency **ALERT** Declared for the subarea of FE-Northeast Ohio due to generation loss and forced outages.

Maximum Generation Emergency Declarations
through June 2024
(Updated 08/30/2024)

2011

- 06/08/2011 12:00-19:00 EST –MISO RC declared a Maximum Generation Emergency **Alert** for the following entities: Central Region Market area(s) of: AMIL, AMMO, AMRN, BREC, CIN, CWLD, CWLP, HE, IPL, SIGE, SIPC and East Region Market area(s) of: ALTE, MECS, MGE, NIPS, UPPC, WEC, WPS and West Region Market area(s) of: ALTW, DPC, MEC, MPW due to Above Normal Temps.
    - This Alert does not include the following LBA's: GRE, NSP, SMP, MP, OTP, MDU, which are all in the Minnesota and the Dakotas area. Temperatures have dropped considerably from yesterday in this area.
- 07/18/2011 14:00-15:00 EST - Market Footprint Maximum Generation Emergency ALERT The reason for the **Alert** is because of Above Normal Temps and Higher than Forecasted Load.
- 07/21/2011 13:00 EST – 17:30 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Above Normal Temps.
- 07/21/2011 15:00-17:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Warning is because of Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 07/21/2011 12:00-15:00 EST - Market Footprint Maximum Generation Emergency **EVENT (Step 1)** The reason for the Event is because of Forced Generation

Maximum Generation Emergency Declarations
through June 2024
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2012

- 06/28/2012 14:00-19:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 06/29/2012 14:00-15:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/02/2012 14:00-20:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/05/2012 14:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps.
  07/05/2012 14:00-17:45 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:00-12:30 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/06/2012 12:30-18:30 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Forced Generation Outages, Above Normal Temps.
- 07/17/2012 12:00-13:00 EST - Market Footprint Maximum Generation Emergency **WARNING** The reason for the Alert is because of Above Normal Temps, Higher than Forecasted Load, Forced Generation Outages.
- 07/17/2012 13:00 – 17:45 EST: The MISO Reliability Coordinator (RC) is declaring a Maximum Generation Emergency **Alert** for the following entities: Market Footprint. The reason for the alert is Forced Generation Outages, Above Normal Temps.
- 07/17/2012 13:00-17:45 EST - Market Footprint Maximum Generation Emergency **Event Step - 1A.** The reason for the Alert is because of Above Normal Temps, Forced Generation Outages.

Maximum Generation Emergency Declarations
through June 2024
(Updated 08/30/2024)

2013

07/17/2013 14:00-19:00 EST - The MISO Reliability Coordinator (RC) declared a Maximum Generation Emergency **Alert** for the following entities: Market Footprint due to Above Normal Temps, Higher than Forecasted Load

Maximum Generation Emergency Declarations
through June 2024
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2014

- 01/07/2014 07:15-12:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 01/07/2014 07:30-11:15 EST - Market Footprint Maximum Generation Emergency WARNING The reason for the **Alert** is because of Forced Generation Outages.
- 01/07/2014 11:15 – 22:00 EST - Market Footprint Maximum Generation Emergency **ALERT** The reason for the Alert is because of Forced Generation Outages.
- 3/3/2014 05:30 EST – 11:00 EST: MISO Declared Maximum Generation Alert for the entire Market Footprint
- 3/4/2014 07:00 EST – 07:30 EST: MISO Maximum Generation **Alert** declared for MISO Balancing authority due to forced and unforced generation reductions combined with reduced NSI imports the reason.
- 3/4/2014 07:30 EST – 10:00 EST: MISO Maximum Generation **Event Step 1a** declared, AME units started, and external resources (Module E) scheduled into MISO.

Maximum Generation Emergency Declarations
through June 2024
(Updated 08/30/2024)

2016

- 06/17/2016 12:00 – 20:00 EST: MISO declared Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages and Above Normal temperatures
- 07/21/2016 12:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Alert**
- 07/21/2016 13:00 – 13:00 EST: MISO declared Maximum Generation Emergency **Warning**. Emergency Pricing Offer Floor 1 initiated
- 07/21/2016 13:00 – 16:00 EST: MISO declared Maximum Generation Emergency **Event 1B/C** and Energy Emergency Alert Level 1 (EEA 1)
- 07/21/2016 16:00 – 18:00 EST: MISO downgraded to Maximum Generation Emergency **Alert** and Energy Emergency Alert Level 0 (EEA 0)
- 08/29/2016 12:00 – 22:00 EST: The MISO Reliability Coordinator (RC) declared a Maximum Generation **Alert** effective for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Higher than Forecasted Load and Forced Generation Outages
- 10/04/2016 16:30 – 19:00 EST: MISO declared a Maximum Generation **Alert** for the South Region of the MISO footprint including the area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages and congestion
- 10/05/2016 13:00 – 15:00 EST: MISO declared Maximum Generation **Alert** for the South Region because of forced generation outages.
- 10/05/2016 15:00 – 15:00 EST: MISO declared Maximum Generation **Warning** and initiated Emergency Pricing Offer Floor 1 for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 10/05/2016 15:00 – 18:00 EST: MISO downgrade from the Maximum Generation Warning Level to a Maximum Generation **Alert** for the South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase in schedule purchases from Southern Company (SOCO). The Maximum Generation Alert remained in effect due to forced generation outages

Maximum Generation Emergency Declarations
through June 2024
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2017

- 04/04/2017 15:00-22:00 EST: MISO declared a Maximum Generation **Alert** declared for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages. Upgraded to MISO declared a Maximum Generation Event at 14:00 EST
- 04/04/2017 14:00-15:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA-1 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation and Transmission outages – emergency ranges enabled
- 04/04/2017 15:00-21:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA-2 for South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME because of Forced Generation and Transmission Outages. – LMM/LMRs implemented
- 04/28/2017 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO South Region due to long term Forced Generation Outages
- 04/28/2017 14:00 – 20:00 EST: MISO escalated the Maximum Generation **Alert** to a Maximum Generation **Warning** for the MISO South Region due to long term Forced Generation Outages
- 04/29/2017 13:00-15:30 EST: MISO declared a Maximum Generation **Alert** for the South Region due to long term Forced Generation Outages
- 09/21/2017 12:00 – 20:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/22/2017 12:30 – 14:00 EST: MISO declared a Maximum Generation **Alert** for the MISO Market Footprint due to generation outages, above normal temperatures, high loads, and heavy congestion
- 09/22/2017 14:00 – 14:30 EST: MISO declared a Maximum Generation **Event Step 1a (AME Resources**) due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access AME Resources
- 09/22/2017 14:30 – 18:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion to access Emergency Maximum Limits In addition, declared NERC EEA 1. All available Resources in use.
- 09/23/2017 13:00 – 14:00 EST: MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

- 09/23/2017 14:00 – 17:15 EST: MISO declared a Maximum Generation **Warning** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion
- 09/25/2017 13:00 – 19:00 EST MISO declared a Maximum Generation **Alert** due to generation outages, above normal temperatures, seasonally high load, and heavy congestion

Maximum Generation Emergency Declarations
through June 2024
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2018

- 01/17/2018 05:00 – 23:15 EST: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced Generation Outages and higher than forecasted load
- 01/17/2018 06:00 – 09:00 EST : MISO declared Maximum Generation **Alert** for Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, OVEC, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced Generation Outages and higher than forecasted load
- 01/17/2018 07:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load
- 01/17/2018 06:10 EST – 14:00 EST: MISO declared a Maximum Generation **Event Step 2c/d** (NERC EEA Level 2 already in effect) for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Higher than Forecasted Load.
- 01/17/2018 14:00 – 19:00 EST: MISO reduced to a Maximum Generation **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 19:00 – 20:55 EST: MISO advanced to a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 20:55 – 23:15 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/17/2018 23:15 EST – 01/18/2018 10:45: MISO declared a Maximum Generation **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared to a Maximum Generation **Event Step 2c/d** and NERC EEA 2 for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 01/18/2018 06:00 – 10:45 EST: MISO declared a Maximum Generation **Event Step 2d (Public Appeals)** (NERC EEA Level 2 already in effect) for the South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 5/14/2018 12:00 EST – *5/13/2018 15:46 EST*: MISO declared a Maximum Generation **Alert** for the entire footprint effective Monday 05/14/2018 12:00 EST until Wednesday 05/16/2018 23:59 EST because of Forced Generation Outages and Above Normal Temps.
    - Maximum Generation Alert terminated on 05/13/2018 15:46 EST due to an increase in capacity.
- 06/04/2018 09:00 – 13:55 EST: MISO declared a Maximum Generation **Alert** for the following entities: South Region area(s) of: CLEC, EES, LAGN due to Forced Generation Outages
- 07/05/2018 11:00 – 17:30 EST: MISO declared a Maximum Generation **Alert** for the following entities: for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load
- 09/13/2018: MISO issued a **Capacity Advisory** due to limited generation surplus on Monday September 17
- 09/14/2018: Capacity Advisory extended to include Tuesday September 18
- 09/15/2018 13:05 – 15:00 EST: MISO declared a Maximum Generation **Alert** for the South Region
- 09/15/2018 15:00 – 18:00 EST: MISO declared a NERC EEA-2 and Maximum Generation **Event Step 2 c/d** for the South Region
- 09/15/2018 18:00 – 18:30 EST: MISO lowered to a NERC EEA-1 and Maximum Generation **Event Step 1 b/c** for the South Region
- 09/17/2018 12:00 EST – 17:30 EST: MISO declared a Maximum Generation **Alert** for the entire MISO Balancing Authority footprint
- 10/05/2018: MISO issued a **Capacity Advisory** Communication for Monday 10/08/2018

Maximum Generation Emergency Declarations
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2019

- 01/30/2019 05:00 – 12:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages and high load.
- 01/30/2019 08:00 – 22:00 EST: MISO declared a Maximum Generation **Event Step 2a/b** and NERC EEA 2 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to forced generation outages and high load.
- 01/30/2019 13:30 EST – 01/31/2019 11:00 EST: MISO declared a Maximum Generation **Event Step 1a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of Higher than Forecasted Load, Forced Generation Outages.
- 01/31/2019 07:00 – 11:00 EST: MISO declared a Maximum Generation **Event Step 1b/c** and NERC EEA Level 1 for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP. The reason for the Event is because of extreme low temperatures and high loads
- 01/31/2019 09:30 – 11:00 EST: MISO declared a Maximum Generation **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, HE, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to extreme temperatures and high load
- 05/16/2019 12:00 EST – 05/18/2019 20:00 EST: MISO issued a Maximum Generation **Capacity Advisory** for the South Region. Forward looking capacity assessments indicated limited operating capacity margins.

- 05/16/2019 12:00 – 14:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 14:00 – 18:00 EST: MISO declared Maximum Generation Emergency **Event Step 2a** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/16/2019 18:00 – 20:00 EST: MISO downgraded to a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME
- 05/17/2019 12:00 – 20:00 EST: MISO declared a Maximum Generation Emergency **Alert** for South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced generation outages
- 05/20/2019 06:00 EST – 05/24/2019 22:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the South Region
- 05/23/2019 12:00 – 22:00 EST: MISO declared a Maximum Generation Emergency **Alert** for the South Region area(s) of: CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Planned and Forced Generation Outages, as well as Above Normal Temps.
- 06/03/2019 12:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted Load and forced Generation Outages
- 06/03/2019 13:00 – 17:00 EST: MISO declares Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to higher than forecasted load and forced generation outages
- 06/03/2019 17:00 EST – 06/04/2019 20:00 EST: MISO declares a Maximum Generation **Capacity Advisory** for MISO South Region
- 06/20/2019 14:00 – 17:30 EST: MISO declared Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to forced transmission and generation outages.
- 07/19/2019 10:00 EST – 07/20/2019 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for the entire MISO Market footprint.

Maximum Generation Emergency Declarations
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2020

- 02/21/2020 07:30 – 09:00 EST: MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to cold weather and units not able to start. All reserve requirements and reliable operations were maintained during this time period.
    - Units unable to start prior to the morning peak resulted in maximum generation conditions
    - South Region weather was colder than normal but not unseasonably cold. Temperatures in Arkansas were in the low 20s.
- 07/06/2020 8:00 EST – 07/10/2020 14:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions of the Market Footprint.
- 07/07/2020 13:00 – 17:30 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO Central and North Regions.
- 07/07/2020 13:00 – 17:30 EST: MISO is escalating the Max Gen Alert to a Maximum Generation Emergency **Warning** for the MISO North and Central Regions only. While the included projected calculations show a slight shortage, this escalation to the Warning level allows some actions to be taken that will relieve the capacity shortage
- 07/07/2020 13:00 - 17:30 EST: MISO declared a Maximum Generation Event **Step 1a** for Central and North Regions (no EEA declared)
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Warning** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura
- 08/27/2020 11:00 EST – 22:54 EST: MISO is declaring a Maximum Generation Emergency **Event Step 5** for the South Region Western half of the WOTAB load pocket (including all of the Western load pocket) due to forced generation and transmission outages and unpredictable load patterns resulting from Hurricane Laura. EEA Level 3 and VOLL Pricing implemented.
    - 12:02 EST: 300 MW of Load Shed for the Max Gen area ordered
    - 13:22 EST: 200 MW of additional Load Shed was ordered for the Max Gen area.
    - Maximum Generation Emergency declarations terminated after transmission returned to service

Maximum Generation Emergency Declarations
through June 2024
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2021

- 02/15/2021 07:00 – 22:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the MISO South Region
- 02/15/2021 09:00 EST – 02/19/2021 11:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** for the South Region.
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, and high loads due to Extreme Winter Temps
- 02/15/2021 18:00 – 23:59 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme cold Temps.
- 02/16/2021 00:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load.'
- 02/16/2021 08:00 – 22:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Extreme Cold Temps
- 02/16/2021 07:30 – 14:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1b** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP (EEA 1) due to Forced Generation Outages and Transmission Constraints.
- 02/16/2021 18:35 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Force Generation Outages, Higher than Forecasted Load
- 02/16/2021 19:40 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 5** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 3) due to Forced Generation Outages, Higher than Forecasted Load

  - 19:50 EST: 700 MW Firm Load Shed requested
- 02/16/2021 22:00 EST – 02/17/2021 01:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 00:00 – 02:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 1a** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages
- 02/17/2021 02:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to forced generation outages.
- 02/17/2021 18:00 – 23:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2c** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 2) due to Forced Generation Outages, Below Normal Temps
- 02/17/2021 21:30 EST – 02/19/2021 11:00 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME (EEA 0) due to Forced Generation Outages, Higher than Forecasted Load
- 06/08/2021 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the MISO North and Central Regions only The Reserve Margin for the North and Central Regions is forecasted to be 3.9% on 06/08/2021. This is below the 5% threshold.
- 06/10/2021 10:00 – 20:00 EST: MISO is declaring a Maximum Generation **Capacity Advisory** its North and Central Regions only – expanded to MISO footprint
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Above Normal Temps, Forced Generation Outages.
- 06/10/2021 13:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD,

CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load

- 06/10/2021 14:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Event Step 2a** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/10/2021 17:00 – 18:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 06/28/2021 12:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.
- 06/29/2021 11:00 – 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Forced Generation Outages.
- 07/05/2021 08:00 EST – 07/06/2021 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the North and Central Regions
- 07/06/2021 13:00 – 18:30 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region

area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to Higher than Forecasted Load, Forced Generation Outages.

- 07/19/2021 06:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for North and Central Regions
- 07/27/2021 06:00 – 07/28/2021 22:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** for the entire market footprint
- 08/19/2021 12:00 – 22:10 EST: The MISO Reliability Coordinator is declaring a Maximum Generation **Capacity Advisory** NORTH and CENTRAL Regions
- 08/23/2021 08:00 EST – 08/25/2021 20:00 EST: MISO declared a Maximum Generation **Capacity Advisory** for entire MISO footprint
- 08/24/2021 15:00 – 19:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP due to above normal temperatures, generation outages, heavy congestion.
- 08/25/2021 09:00 – 20:00 EST: MISO is declaring a Maximum Generation Emergency **Alert** for the North and Central Regions of MISO due to Above Normal Temps, Forced Generation Outages
- 10/04/2021 07:00 – 20:10 EST: MISO declared a **Capacity Advisory** for North and Central Regions due to forced generation outages and tight capacity conditions.
- 10/04/2021 12:00 – 12:00 EST: MISO declared a Maximum Generation Emergency **Alert** for Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages.
    - System conditions improved prior to start time of the alert and was cancelled prior to start.
    - Although the Maximum Generation Alert was cancelled prior to start time due to improved system conditions, Conservative Operations and Capacity

Advisory were maintained to ensure continued reliability in tight capacity conditions.

2022

- 01/07/2022 06:00 – 09:30 EST: MISO Reliability Coordinator is declaring a Maximum Generation Emergency **Warning** the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to forced generation outages
- 05/12/2022 14:45 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps.
- 05/12/2022 19:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
    - This Alert is the de-escalation of the earlier Maximum Generation Warning.
- 05/13/2022 15:35 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS due to Forced Generation Outages, Higher than Forecasted Load, Above Normal Temps
- 05/18/2022 08:30 EST – 05/19/2022 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO South Region due to reduced reserve margins
- 05/18/2022 14:30 – 19:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due Forced Generation Outages, Above Normal Temperatures and Higher than Forecasted Load
- 06/15/2022 08:00 – 06/16/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Market Footprint
- 06/13/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: South Region

area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Forced Generation Outages, Above Normal Temps, High Congestion

- 06/15/2022 13:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Alert** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, High Congestion
- 06/20/2022 06:00 – 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the South Region only
- 06/21/2022 06:00 EST – 06/23/2022 22:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the Market Footprint
- 07/05/2022 10:00 – 20:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Capacity Advisory** for the MISO Balancing Authority
- 09/20/2022 01:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market footprint
- 10/12/2022 14:00 – 19:00 EST: The MISO Reliability Coordinator declared a Maximum Generation **Capacity Advisory** for the MISO Market South Region.
- 12/23/2022 09:15 – 13:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to Higher than Forecasted Load, Forced Generation Outages
- 12/23/2022 16:30 – 17:30 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Warning** for the following entities: the ENTIRE MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 17:30 – 18:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 1b – EEA1** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load
- 12/23/2022 18:00 – 21:00 EST: The MISO Reliability Coordinator declared a Maximum Generation Emergency **Event Step 2a – EEA2** for the following entities: MISO Balancing Authority Area due to Forced Generation Outages, Higher than Forecasted Load

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2023

- 06/02/2023 07:00 - 21:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** due to elevated temperatures, forced generation outages, and higher than normal forecasted loads.
- 06/26/2023 13:00 - 16:07 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for MISO South Region
- 06/29/2023 12:00 – 22:01 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the Market Footprint due to extreme heat and high load
- 07/26/2023 12:00 EST – 07/28/2023 20:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Capacity Advisory** for the MISO North and Central Regions
- 07/27/2023 12:00 – 18:00 EST: MISO Reliability Coordinator declared a **Maximum Generation Emergency Ale**rt for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Above Normal Temps, Forced Generation Outage
    - MISO is forecasting high load which may cause MISO to be within 500 MW of obligations for operating day Thursday 07/27/2023.
    - With increased risk and uncertainty, it may be necessary for MISO to escalate further based on changing system conditions
- 07/28/2023 12:00 – 20:00 EST: MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: Central Region area(s) of: AEP, ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, BWLT, CETO, CIN, CONS, CWLD, CWLP, DECO, GLH, GLHB, HE, HMPL, IPL, ITC, MCS-WPSC, MEC1, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MCS-BEPC, MCS-CBPC, MCS-CFU, MDU, MEC, MHEB, MP, MPCN, MPW, NSP, OTP, RPU, SMP, WMUT due to Forced Generation Outages, Above Normal Temps
- 08/14/2023 10:00 – 20:00 EST: The MISO Reliability Coordinator is declaring a Maximum Generation Capacity Advisory for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

- 08/21/2023 10:00 EST – 08/24/2023 23:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Capacity Advisory** for the MISO Market Footprint
- 08/24/2023 12:00 – 12:00 EST: The MISO Reliability Coordinator is declaring a **Maximum Generation Emergency Alert** for the following entities: MISO Balancing Authority Area
    - Escalated to Maximum Generation Emergency Step 2a before start of the Alert
- 08/24/2023 12:00 – 19:30 EST: MISO is escalating to a **Maximum Generation Emergency Event Step 2a** for the MISO Balancing Authority Area due to Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.
- 08/24/2023 19:30 – 21:00 EST: MISO is de-escalating Maximum Generation Event Step 2A to **Maximum Generation Warning**

2024

- 5/07/2024 11:00 – 19:00 EST: MISO declared **Capacity Advisory** for South Region areas of AXLT, CLEC, CWLT, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME due to an increase of load forecast, forced generation outages, and limited transfer capabilities from the MISO Classic Region to the MISO South Region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 33

MISO Market Capacity Emergency

MISO Market Capacity Emergency

SO-P-EOP-11-002 Rev: 21

ROLE			ROLE	
BAO	☑		SM	☑
IRAC	☑		RC	☑
UDS	☑		G&I	☑
SOE	☑		LBA	☑
TOP	☑		MP	☑
GOP	☑		ORM	☑

Rev History	Reason for Issue	Revised By	Issue Date	Effective Date
21	Annual Review. Added actions under Step 4.2.8. Updated procedure number. Added Operations Risk Management (ORM) Role. Removed references to MCS when not related to LMM, LMR or EDR. Compliance Review Completed. Operating procedure owner approval on file.	Chris Hoffman/ Becca Skalko/ Bill Puller	03/03/2025	03/03/2025
20	Annual Review. No changes. Compliance Review Completed. Operating procedure owner approval on file.	Chris Benton/ Becca Skalko/ Bill Puller	06/01/2024	06/01/2024

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1.0 Purpose

Provide a set of emergency Operating Plans to address Capacity Emergencies and Energy Emergencies within the MISO Balancing Authority Area (MBAA), which shall include the following:

1. Roles and responsibilities for the MISO Operators, Local Balancing Authorities (LBAs), Transmission Operators (TOPs), Generation Operators (GOPs), and Market Participants (MPs).
2. Process for preparation, management, and recovery from an Emergency.

2.0 Precautions and Limitations

1. As conditions require, MISO may provide instructions to move to any section or step in this procedure while providing instructions to complete actions described in earlier levels or steps as time permits.
2. Should sufficient relief be obtained during the implementation of one of the actions during a declaration step, subsequent actions within that declaration step need NOT be taken.
3. The Operating Reserve Requirement for the MBAA consists of Regulation and Contingency Reserve Requirements.
4. The Operating Reserve Requirement for a Region or Sub-Area consists of a Contingency Reserve Requirement based on the Most Severe Single Contingency (MSSC) within its boundaries.
5. Available Economic Resources are the Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for Constraint Stranded MW and NSI Obligations.
6. South Region Available Economic Resources are the South Available Economic Max (including BTM but reduced by Resources that cannot be committed due to congestion or excessive Time-to-Start) and adjusted for South Constraint Stranded MW, the Regional Dispatch Transfer NSI (RDT NSI), and Resources from the Central and North Regions that are deliverable to the South via the RDT up to the Regional Dispatch Transfer Limit (RDTL, typically 3,000 MW).
7. The 5% Reserve Margin Entry Condition for an MBAA Capacity Advisory includes allowance for loss of the MSSC and subsequent recovery within 90 minutes for the second MSSC (if applicable), plus uncertainties.

8. Increasing the Reserve Margin Entry Condition may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.
9. MISO will use the Mid-term Load Forecast (MTLF) or Short-term Load forecast (STLF) where applicable to determine available Operating Reserves. MISO may adjust the load forecast values based on sustained error over time and will document the reasons for the adjustment.
10. Transmission System Emergencies that require immediate action will be declared and resolved through actions identified in MISO SO-P-EOP-00-004 Transmission System Emergency. Transmission constraints, which result in limitations in transferring energy into the MBAA or a sizable sub-area of the MBAA and result in a capacity or energy Emergency for such area will be managed through the current procedure.
11. Energy deficient BA obligations include immediate actions to mitigate any undue risk to the Interconnection, including Load shedding.
12. MISO posts Max Gen Declaration notification to the MISO Market and Operations - Real-Time Operations Website.
13. Depending on the urgency of the Max Gen Emergency, manual Load Shedding may be used to control the Emergency at any time. This includes the immediate shedding of load to return Area Control Error (ACE) to zero.
14. MISO's posting of the Max Gen Declaration notification to the RT Ops Website [via Operator Interface (OI)] serves as notice of the existence and duration of the conditions requiring the implementation of the procedures set forth in Section 40.2.20 of the Tariff. Historical Max Gen Declarations can be found on the MISO’s Open Access Same Time Information System (OASIS) page.
15. MISO will render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory or statutory requirements.
16. If MISO is NOT able to send Load Modifying Resource (LMR) availability reminders to MPs, MISO will communicate, via the Demand Side Resource Interface (DSRI) Tool, implementation instructions using the then current availability information in the tool, assuming it to be correct.
17. MISO Shift Manager (SM) should evaluate additional staffing requirements per SO-I-NOP-00-441 Real-Time Event Resolution.

18. The Reserve Procurement Enhancement (RPE) objective for the RDT North-to-South is to elevate MCP and energy prices in the South Region to clear additional Contingency Reserves to allow recovery of the RDT Flow to 116% post-contingent of the South MSSC. Operators must determine how to reduce the RDT Flow further to 100% from 116%. When RPE on RDT is violating, additional generation should be started.
19. An infographic of MISO's Market Capacity Emergency Procedure steps is included in Attachment 8 — Summary of Market Capacity Emergency Procedure Steps.

3.0 Entry Conditions

3.1 Capacity Advisory

1. Entry conditions are based on the Reserve Margin, which is the Total Operating Reserves compared to the Operating Reserve Requirement, either in MW or % of the Load, plus Operating Reserve Requirements. Attachment 1 — Reserve Margin Example Calculations has example calculations.
   - Reserve Margin:
     Total Operating Reserves - Operating Reserve Requirement
   - Reserve Margin (%):
     100 * (Total Operating Reserves - Operating Reserve Requirement) /(Load + Operating Reserve Requirement)
   - Total Operating Reserves MBAA:
     (Avail Eco Max - Constraint Stranded - NSI) - Load
   - Total Operating Reserves South Region:
     (Avail Eco Max - Constraint Stranded - RDT NSI + RDTL) - Load

ORM/ SM

Note [□]

- IF a positive but somewhat low Reserve Margin is forecast THEN:
- A Capacity Advisory will typically be declared 2 to 3 days in advance, however, it may be declared in any time frame.
- A decision to declare a Capacity Advisory may take into account other information such as time frame, weather and other risk factors
- Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other uncertainties or risks to the Interconnection.

1. IF any of the following conditions are identified THEN **PERFORM** Section 4.1 Capacity Advisory: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin (%) is less than 5%
   - South Region forecasted Reserve Margin is less than 2,000 MW

3.2 Max Gen Alert

SM

Note [□]

- A positive but low Reserve Margin is forecasted in a Max Gen Alert.
- For a negative Reserve Margin, a Warning or Event should be declared.
- Increasing the Reserve Margin may be required when relying on a significant amount of capacity returning from outage or if there are other forecasting uncertainties or risks to the interconnection.

1. IF any of the following conditions are identified, THEN **PERFORM** Section 4.2.2 Max Gen Alert - MISO Actions: [□]
   - MBAA, Region or Sub-Area forecasted Reserve Margin is less than 1500 MW, or largest single contingency for Sub-Area
   - South Region forecasted Reserve Margin is less than 500 MW

3.3 Max Gen Warning

SM

Note [□]

A negative Reserve Margin means that Load and Operating Reserve Requirement cannot be met with normal Economic Resources. In that scenario a Max Gen Warning or Event should be declared.

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.3 Max Gen Warning - MISO Actions: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero

3.4 Max Gen Event

SM

1. IF the following condition is identified, THEN **PERFORM** Section 4.2.4 Max Gen Event Step 1a - MISO Actions when: [□]
   - MBAA, Region, or Sub-Area actual or forecasted Reserve Margin is less than zero
   - Warning level actions are NOT sufficient

4.0 Instructions

4.1 Capacity Advisory

ORM/ SM

4.1.1 Capacity Advisory - MISO Actions

1. **COMMUNICATE** Capacity Advisory as follows: [□]
   - A. **DEFINE** boundaries of Capacity Advisory area. [□]
   - B. **DEFINE** start time of Capacity Advisory and **COMMUNICATE** potential end time to UDS Operator to allow STR Default and RPE MSSC Overrides to be entered. [□]

C. **SEND** Capacity Advisory declaration to affected members via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]

D. **SEND** Capacity Advisory declaration via Reliability Coordinator Information System (RCIS). [□]

SM 2. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

SM 3. IF a significant shortage of Operating Reserves is anticipated in any Reliability Assessment Commitment (RAC) process, THEN **DETERMINE** whether to issue LMR Scheduling Instructions in anticipation of a Max Gen Emergency Event Step 2a or higher. [□]

A. **SEND** informational message via MCS/OI to impacted area(s) that LMRs have been called in anticipation of a Max Gen Emergency. [□]

B. **SEND** LMR scheduling instructions (from longest to shortest lead time) via MCS for forecasted Max Gen Emergency. [□]

UDS **Note** [□]

For Steps 4. through 7., REFER to Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions.

4. IF a Capacity Advisory is declared for the North/Central Region only, THEN **OVERRIDE** STR RPE MSSC Default value(s) as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing for Non-Zone only in the EMD Global Reserve Requirements menu, for the duration of a Capacity Advisory or higher declaration. [□]

UDS 5. IF during the course of a Capacity Advisory or higher declaration for the North/Central Region, and a Capacity Advisory or higher declaration is declared for the South Region, THEN **OVERRIDE** System Wide STR Default value(s) and **OVERRIDE** South Region STR RPE MSSC in Zone 8 in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or Higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

6. IF a Capacity Advisory is declared for the South Region only, THEN **OVERRIDE** STR RPE MSSC Default value(s) in Zone 8 only in the EMD Global Reserve Requirements menu, for the duration of the Capacity Advisory or higher declaration, as specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

7. IF during the course of a Capacity Advisory or higher declaration for the South Region, a Capacity Advisory or higher declaration is added for the North/Central Region, THEN **OVERRIDE** System Wide STR Default value(s) and **OVERRIDE** North/ Central STR RPE MSSC for Non-Zone in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or higher declaration, as specified in SO-I- EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]
8. IF a System Wide Capacity Advisory is declared, THEN **OVERRIDE** STR Default value(s) AND Override North/Central STR RPE MSSC for Non-Zone AND Override South Region STR RPE MSSC for Zone 8 as specified per SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing in the EMD Global Reserve Requirements menu for the duration of Capacity Advisory or above declaration. [□]

ORM/ SM

9. NOTIFY Day Ahead (DA) and Forward Reliability Assessment and Commitment (FRAC) operators when STR update is complete. [□]

4.1.2 Capacity Advisory - MISO Stakeholder Actions

1. WHEN notified by MISO, THEN **ENSURE** all market data is updated with best available information for operating day(s) including the following: [□]
   - Facility and generation availability, outages and de-rates
   - Generation Offers, including any changes to reflect fuel availability
   - Fuel supply and inventory concerns
   - Fuel switching capabilities
   - Environmental constraints
   - Load forecast Values
   - LMR Availability in the DSRI
   - Voluntary Load Management information

- Load Management Measures (LMM) and any Voluntary Load Management in the MCS
- Emergency Demand Response (EDR) offers

MP

Note

LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.

2. IF notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP

3. **UPDATE** DSRI Tool as follows: [□]
   A. **NAVIGATE** to the Active Event by clicking either of the following: [□]
      - the Scheduling Instruction event banner
      - the Active Event from the dashboard, or
      - the Events tab
   B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]
   C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]
   D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]
   E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]
   F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.2 MISO Actions during a Max Gen Emergency

4.2.1 Max Gen Declaration - MISO Actions

SM 1. **DECLARE** applicable Max Gen Alert/Warning/Event as follows: [□]
   A. **DEFINE** boundaries of declaration area. [□]
   B. **DEFINE** start and end time of declaration. [□]
   C. **SEND** Max Gen Declaration via OI per SO-I-NOP-00-448 Event Communications Matrix. [□]
   D. SEND Max Gen declaration summary information via RCIS within 30 minutes. [□]

SM 2. **ENSURE** Conservative System Operations has been declared per SO-P-NOP-00-449 Conservative System Operations. [□]

SM 3. IF OI is down or SM determines a conference call is necessary, THEN **PERFORM** conference call with affected reliability entities per SO-P-NOP-00-483 Reliability Coordination Conference Call. [□]

4.2.2 Max Gen Alert - MISO Actions

SM 1. IF starting declaration at a Max Gen Alert, THEN **DECLARE** Max Gen Alert per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS 2. **IMPLEMENT** Emergency Pricing Tier 0 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM **Note** [□]

This survey is to gain an idea of amount of LMM load reduction to expect to be available if needed.

3. **SEND** survey via MCS LMM Tool in the Load Management Tab to LBAs to ensure LMM information is updated. [□]
   A. IF the Drill Mode is currently on. THEN **ENSURE** to “Switch to Live Mode”. [□]

BAO 4. IF Operating Reserve availability changes are identified, THEN **NOTIFY** SM. [□]

IRAC 5. **ENSURE** available economic resources are committed to meet load, firm transactions, and reserve requirements. [□]

G&I

A. COORDINATE with MPs with Module E Resources as follows: [□]

(1.) **DETERMINE** available Resources for implementation during potential Warning declaration. [□]

B. IF MPs have remaining available External and Internal Resources (Module E registered Capacity Resources), THEN **REQUEST** amount available for implementation during potential Warning declaration. [□]

(1.) **ENSURE** MPs identify specific information on physical location and path External Resources (Module E registered Capacity Resources) would use to deliver energy into potential Warning area. [□]

SM
G&I

C. **NOTIFY** SM of Total MW of non-firm energy sales and MISO exporting Capacity Resources. [□]

RC

Note [□]

The following analysis should be completed in time for implementation during the potential Warning declaration.

D. **COORDINATE** with neighboring Reliability Coordinators (RCs) and MISO TOPs to raise transfer capability into declaration area or make available constraint stranded generation (on or off line) in declaration area including: review Transmission Loading Relief (TLR) activity, binding constraints, available reconfiguration options, and use of short term emergency ratings. [□]

UDS

E. **LOG** actions taken and relevant information in response to the declaration. [□]

Note [□]

- Actions are taken to attempt to preserve Resources dedicated to firm Load and maintaining Operating Reserves.
- Actions available at this level should be fully utilized, time permitting, for all entities within the defined declaration area prior to declaring an emergency.

4.2.3 Max Gen Warning - MISO Actions

SM

1. IF starting declaration at a Max Gen Warning or escalating from a Max Gen Alert, THEN **DECLARE** Max Gen Warning per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS	2.	**IMPLEMENT** Emergency Pricing Tier 1 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]
IRAC	3.	**SUSPEND** Coordinated Transaction Scheduling (CTS) for the duration of the capacity emergency per SO-I-AOP-00-224 CTS Failure Modes. [□]
G&I	4.	**COMMUNICATE** CTS suspension with PJM. [□]
SM	5.	**REVIEW** EDR offers to determine EDR availability and MW amounts for Warning period. [□]
SM	6.	**OBTAIN** updated MW amounts of relief available during effective Warning period by LBA from MCS. [□] • LMMs – Stage 1 • LMMs – Stage 2
SM	7.	**REVIEW** LMRs availability in MCS-LMR Tool for declaration period. [□]
SM	8.	**DIRECT** the following to raise forecasted capacity: [□]
BAO		A. **TERMINATE** Inadvertent Payback process per SO-I-NOP-00-462 Inadvertent Interchange Management. [□]
BAO		B. **DETERMINE** if request for time error correction termination should be made per SO-P-NOP-00-455 Balancing Authority Operations. [□]
SM	9.	**SEND** OI message to MPs to schedule remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to Warning area, given transmission constraints. [□]
SM/ G&I	10.	**COORDINATE** to notify MPs to schedule Module E Resources into MBAA declaration area as follows: [□]
G&I		A. **PROVIDE** instructions on amount and time to schedule External and Internal Module E Resources into declaration area. [□]
G&I	11.	**NOTIFY** SM of forecasted changes in MBAA NSI due to loss of imports. [□]
G&I	12.	**COORDINATE** to determine amount of non-firm Export Schedules to curtail. [□]

G&I 13. IF Export Schedule Limits are exceeded, THEN **CURTAIL** Export Schedules from declaration area in amounts required to relieve shortage condition in the following order per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions: [□]

A. Non-Firm Transmission Schedules.
B. Firm Schedules from Capacity (Module E) Resources that are NOT meeting their Schedule requirements and Capacity requirements.
C. Firm Schedules from non-Capacity (Module E) Resources that are NOT meeting their Schedule requirements.
D. Firm Transmission schedules from Power Purchase Agreements (PPAs) that represent a Fleet of Resources, when those resources are NOT meeting their collective resource obligation.

G&I 14. **MODIFY** webTrans E-tag validation mode to reflect Max Gen in affected area (North, South, or All) per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

RC 15. **NOTIFY** TOP to implement reconfiguration options agreed upon to raise transfer capability into declaration area or alleviate constraint stranded generation in declaration area. [□]

ALL 16. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.4 Max Gen Event Step 1a - MISO Actions

SM

Note [□]

Actions in this section are taken to attempt to preserve Resources dedicated to firm Load and maintaining Regulating Reserves.

1. IF starting declaration at a Max Gen Event Step 1a or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event 1a per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM

2. **NOTIFY** Director On-Call to implement SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies. [□]

IRAC

Note [□]

AME are resources with a commit status of Emergency.

3. **COMMIT** the following Available Max Emergency (AME) designated resources: [□]
   - Generation Resources
   - Demand Response Resources – Type 1
   - Demand Response Resources – Type 2

4.2.5 Max Gen Event Step 1b - MISO Actions

SM

1. IF starting declaration at a Max Gen Event Step 1b or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 1b and EEA1 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

IRAC

Note [□]

IRAC Operator ensuring emergency ranges are available for use by UDS and UDS Operator verifying these ranges are preliminary actions to implementing these ranges in Event Step 1b.

2. **ENSURE** unit emergency ranges are pushed per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

UDS

Note [□]

Resources selected to provide Regulating Reserve for each Generation Resource, Demand Response Resource – Type II and External Asynchronous Resource for use in MISO's RAC, Automatic Generation Control (AGC), and UDS for the MBAA (or sub-area due to a transmission constraint) are to be excluded when implementing Emergency Maximum Limits.

3. **ACTIVATE** Emergency Maximum Limits per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

ALL

4. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.6 Max Gen Event Step 2a - MISO Actions

SM

Note [□]

- LMM – Stage 1 and LMRs are utilized on a pro-rata basis within the declaration area based on availability of those actions, with the exception of EDRs, which are committed in merit order.
- LMRs can be called in anticipation up to one hour prior to their required notification time. If MISO does NOT declare a Max Gen Emergency Event Step 2a or higher at least two hours prior to the start of the Scheduling Instructions issued in anticipation, the LMRs are NOT obligated to perform.

1. IF starting declaration at a Max Gen Event Step 2a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2a and EEA2 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS

2. **ENSURE** emergency pricing has been implemented as follows:
   - If previously implemented, THEN **CHANGE** to Tier 2. [□]
   - If NOT previously implemented, THEN **IMPLEMENT** Emergency Pricing Tier 2 per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

SM

3. **DETERMINE** Manitoba Hydro's EEA status. [□]

SM

4. IF Manitoba Hydro is in an EEA concurrently with MISO's EEA2 or higher, THEN PERFORM SO-I-NOP-00-481MISO-Manitoba Hydro Concurrent EEA. [□]

SM

Note [□]

- One MW value will be provided per LBA for load reduction.
- Determination of individual LMMs to be utilized will be managed at the LBA level.
- Reduction MW amounts by LBA will be determined by proration of total amount available in declaration area.
- If OI is unavailable, notifications will be made via phone.
- LMR load reduction amounts to LBAs are for information only. LBAs do not implement LMRs

5. **NOTIFY** LBAs of required Load reduction via LMM – Stage 1 and LMRs in MW amounts via MCS. [□]

SM 6. **COORDINATE** with MPs on implementing LMRs as follows: [□]

Note [□]

LMR implementation amounts are determined by taking prorated amount of LMR availability in each LBA area as compared to total available in declaration area, and based upon registration profile of each LMR, within the tolerances as set in the MCS-LMR Tool.

A. **DETERMINE** LMR implementation amounts by MPs. [□]

B. **PROVIDE** a MW minimum implementation amount to each MP based upon this pro-ration and profile of registered LMRs via MISO Communication System (MCS)-LMR Tool. [□]

SM 7. **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 8. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 9. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.7 Max Gen Event Step 2b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 2b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2b per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM 2. **COMMIT** EDR resources, in merit order, to alleviate capacity shortage within declaration area per SO-I-NOP-00-404 Emergency Demand Response Implementation. [□]

ALL 3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.8 Max Gen Event Step 2c - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 2c or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 2c per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM/ RC 2. **COORDINATE** with neighboring RCs and BAs to determine Emergency energy available from external sources. [□]

SM/ G&I 3. **IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements in order to conserve Operating Reserves per SO-I-NOP-00-479 Purchasing and Selling Emergency Energy. [□]

SM 4. **EVALUATE** opportunities to reduce internal energy usage, such as sending non-essential personnel home, reducing lighting that is non-essential for personnel safety and reducing large electric loads. [□]

SM **Note** [□]

DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

5. **INSTRUCT** LBAs in declaration area to issue public appeals to reduce demand per their internal procedures. [□]

ALL 6. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.9 Max Gen Event Step 3a - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 3a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3a per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM 2. **NOTIFY** GOPs, via OI, in the declaration area who have Generators with de-rates from environmental restrictions to request waivers from appropriate government agencies. [□]

BAO 3. **IMPLEMENT** use of all spinning and supplemental reserves as needed and as time permits. [□]

SM 4. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO reasonable actions exist to restore within 90 minutes, THEN **DECLARE** an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

4.2.10 Max Gen Event Step 3b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 3b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 3b per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM **Note** [□]

Reduction MW amounts by LBA will be determined by pro-rata of total amount available in declaration area.

2. **NOTIFY** LBAs, via MCS, of required Load reduction via LMM – Stage 2 in MW of interruptible demands. [□]

RC 3. IF TLR is called and MISO imports are being curtailed, THEN **COORDINATE** with SM to evaluate Priority 6-NN tags to exclude. [□]

SM/ G&I 4. **COORDINATE** to elevate identified Priority 6-NN tags per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

SM/ G&I 5. **NOTIFY** RCs of tags that are being elevated to Firm. [□]

ALL 6. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.11 Max Gen Event Step 4a - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 4a or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4a per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

BAO 2. **IMPLEMENT** Reserve Call from Contingency Reserve Sharing Group (CRSG). [□]

4.2.12 Max Gen Event Step 4b - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 4b or escalating from a lower Max Gen level, THEN **DECLARE** Event Step 4b per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

RC 2. **COORDINATE** with neighboring RCs and BAs to identify additional available Emergency energy, including their Operating Reserves. [□]

G&I 3. **IMPLEMENT** Emergency energy purchases from neighboring BAs through existing Emergency contractual agreements and SO-I-NOP-00-479 Purchasing and Selling Emergency Energy. [□]

SM 4. IF Contingency Reserves fall below minimum required (MSSC) for greater than 30 minutes and NO **reasonable** actions exist to restore within 90 minutes, THEN DELARE an EEA3 per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

IRAC 5. **EVALUATE** excluding Regulating Units that have room between RegMax and Emergency Max from clearing Reg per SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing. [□]

ALL 6. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.13 Max Gen Event Step 5 - MISO Actions

SM 1. IF starting declaration at a Max Gen Event Step 5 or escalating from a lower Max Gen level, THEN **DECLARE** Max Gen Event Step 5 and EEA3per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

SM **Note** [□]

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment provides additional information regarding sharing of load shedding with Slice of System PPAs.

2. **DETERMINE** manual Load Shedding requirements. [□]

SM **Note** [□]

Issuing Emergency Operating Instructions for firm Load shed is based on the ratio of LBA forecasted or actual Load to the total forecasted or actual Load of the declaration area, taking into account applicable transmission security requirements.

3. **ISSUE** Emergency Operating Instructions to LBAs, in declaration area, of MW amounts of load to shed via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

UDS **Note** [□]

Refer to SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing.

4. WHEN notified by MISO SM, THEN **PERFORM** the following:
   A. **CHECK** appropriate box(es) in the Energy Market Display (EMD) for the applicable LBAs in the column titled “Is Voll Price Enforced” [□]
   B. **SAVE** updates. [□]

SM 5. IF firm Load Shed is greater than 100 MW, THEN **DETERMINE** OE-417 reporting responsibilities per SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]

SM 6. **ENSURE** required notifications are performed per SO-I-NOP-00-448 Event Communications Matrix. [□]

ALL 7. **LOG** actions taken and relevant information in response to the declaration. [□]

4.2.14 Max Gen Event Downgrade/Termination - MISO Actions

SM

Note [□]

- Steps and levels during Termination may be skipped as appropriate based on system conditions and projections.
- Emergency steps shall be exited in a controlled and deliberate manner so to NOT adversely affect system reliability while minimizing the impact of these emergency actions on the Load Serving Entities (LSEs).

1. WHEN actual obligations return below total MISO capability, THEN **DOWNGRADE/TERMINATE** Max Gen Event as follows: [□]

SM
   A. **SEND** Max Gen Downgrade/Termination to affected members via OI per Section 4.2.1 Max Gen Declaration - MISO Actions. [□]

UDS
   B. IF Max Gen Event Step 5 is being terminated, THEN **UNCHECK** flag in EMD, which previously set all LMPs and MCPs to the Value of Lost Load (VOLL). [□]

IRAC/ G&I
   C. ENSURE CTS is enabled per SO-I-AOP-00-224 CTS Failure Modes. [□]

UDS
   D. **UPDATE** or **TERMINATE** emergency pricing and emergency ranges per SO-I-EOP-00-001 as applicable. [□]

G&I
   E. **RETURN** webTrans E-tag validation to normal mode per SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions. [□]

IRAC
   F. **EVALUATE** and **DECOMMIT** any online emergency generation (AME) that has met its Min Run. [□]

SM
   G. **PERFORM** necessary actions to back out of steps taken in reverse order. [□]

UDS
   H. IF STR requirement override is NOT needed for remainder of the declared emergency, THEN **REMOVE** STR requirement override in EMD from STR Default and STR MSSC Non-Zone and South Zone 8. [□]

SM
2. **ENSURE** all SO-I-NOP-00-448 Event Communications Matrix notifications are performed. [□]

ALL
3. **LOG** actions taken and relevant information in response to the declaration. [□]

4.3 MISO Stakeholder Actions during a Max Gen Emergency

4.3.1 Max Gen Alert Level Actions - MISO Stakeholder Actions

LBA/ TOP/ GOP

Note [□]

Deferring generation/transmission maintenance until the Max Gen declaration has been terminated ensures trips are minimized.

1. **FOLLOW** MISO's SO-P-NOP-00-449 Conservative System Operations procedure. [□]

LBA/ TOP

2. **DETERMINE** potential exclusions of constrained pockets within declaration area where there is expected to be adequate generation that may NOT be transferred to other parts of declaration area due to local constraints. [□]

TOP

3. **INFORM** MISO RC of identified areas. [□]

GOP

4. IF generators are derated, THEN **PERFORM** the following:

GOP

A. INFORM the following of capacity limited facilities: [□]
   - LBAs
   - TOPs
   - MISO G&I Operator

GOP

5. **UPDATE** Limits and Offers. [□]

MP

Note [□]

- Schedules that source from a resource that is identified as a Capacity Resource in Module E for a MISO LSE must be identified in the tagging process per MISO BPM-007 Physical Scheduling Business Practice Manual Section 16 - Capacity Resource Scheduling.
- This also includes a Generation Resource internal to the MBAA that is identified as a Capacity Resource for an external BA.
- This identification allows for proper curtailment of non-firm imports and exports during a capacity emergency event.

6. **UPDATE** energy interchange transaction e-tags, sourcing or sinking, in MBAA to reflect the firmness of their Capacity Resources. [□]

MP

Note [□]

MISO will provide instructions on when and how much the MP should schedule into MISO during Max Gen Warning.

7. **NOTIFY** MISO G&I Operator of Available External and Internal Resources (Module E registered Capacity Resources) deliverable to the declaration area, including amount available. [□]

MP 8. **ENSURE** accuracy of LMR availability and Self-Scheduled/ Voluntary Load Management LMRs in the DSRI Tool. [□]

LBA 9. **ENSURE** accuracy of Non-LMR Voluntary Load Management/ Self-Scheduled LMM information in the MCS-LMR Tool. [□]

TOP 10. **COORDINATE** with MISO RC to determine reconfiguration options to raise transfer capability to declaration area or alleviate constraint stranded generation in declaration area. [□]

4.3.2 Max Gen Warning - MISO Stakeholder Actions

LBA 1. Based on Load Shed methodology, **MAKE** preparations for potential Load Shed during an Event stage. [□]

MP 2. **UPDATE** EDR offers for availability and MW amounts for declaration period. [□]

LBA 3. **SUBMIT** LMM availability via MCS per Attachment 3 — Load Management Update Form Example. [□]

MP 4. **ENSURE** accuracy of registered LMR availability in the DSRI Tool. [□]

MP 5. WHEN notified by MISO, THEN **SCHEDULE** remaining available External and Internal Resources (Module E Registered Capacity Resources) that would be deliverable to declaration area, given transmission constraints. [□]

LBA 6. **NOTIFY** Interruptible Loads of potential interruption. [□]

LBA/ MP/ TOP/ GOP 7. **LOWER** energy use to a minimum using conservative measures. [□]

TOP 8. **IMPLEMENT** agreed upon reconfiguration options to raise transfer capability into declaration area or make available constraint stranded generation in declaration area. [□]

4.3.3 Max Gen Event Step 1a - MISO Stakeholder Actions

GOP 1. WHEN notified by MISO, THEN **START** applicable off-line AME Generation Resources. [□]

4.3.4 Max Gen Event Step 1b - MISO Stakeholder Actions

GOP

Note [□]

MPs should ensure Emergency Range limits reflect actual resource capabilities. Specific information, limitations, and concerns on Emergency Range usage should be communicated to MISO G&I Operators as applicable.

1. WHEN Resources are dispatched, THEN **ENSURE** Resources move into Emergency range. [□]

GOP 2. **ENSURE** all co-generation and independent power producers are at maximum output and availability. [□]

GOP 3. **NOTIFY** MISO G&I Operator of change in output. [□]

GOP 4. IF additional reliable capacity is available (such as adding additional mills, duct burners, etc.), THEN **COORDINATE** adjustments with MISO G&I Operator. [□]

4.3.5 Max Gen Event Step 2a - MISO Stakeholder Actions

LBA 1. IF in declaration area and notified by MISO to reduce load, THEN **PERFORM** the following: [□]

LBA A. **REDUCE** load via LMM – Stage 1. [□]

LBA **Note** [□]

- Reductions through Load Management are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

B. WHEN load reduction actions have been implemented, THEN **NOTIFY** MISO. [□]

MP **Note** [□]

LMRs should be implemented NO less than the MW amount scheduled and within guidelines given by MISO.

2. WHEN notified by MISO, THEN **IMPLEMENT** LMRs. [□]

MP 3. UPDATE DSRI Tool as follows: [□]

A. **NAVIGATE** to the Active Event by clicking either of the following: [□]

- the Scheduling Instruction event banner
- the Active Event from the dashboard, or
- the Events tab

B. **REVIEW** Event Timeline and LMR Instructions broken down by each LBA. [□]

C. **ACKNOWLEDGE** LMR Scheduling Instructions. [□]

D. **NAVIGATE** to Resource Deployment tab of the Active Event. [□]

E. **ENTER** and **SUBMIT** MW Amounts of Resources that will be deployed in order to meet the LMR Scheduling Instruction obligation per LBA. [□]

F. After receiving the LMR Scheduling Instruction, **UPDATE** LMR Availability of those Resources that were designated to respond to LMR Scheduling Instruction to reflect what is newly available to MISO. [□]

4.3.6 Max Gen Event Step 2b - MISO Stakeholder Actions

MP
1. WHEN notified by MISO, THEN **COMMIT** EDR Resources. [□]

4.3.7 Max Gen Event Step 2c - MISO Stakeholder Actions

LBA

Note [□]

- Public appeals to reduce demand is based on internal LBA procedures, system conditions, and Event projections provided by MISO.
- The public appeals should include an educational message on how the public may reduce demand and conserve power.
- DOE Form OE-417 filing requirements for issuing Public Appeals is the responsibility of the LBA.

1. WHEN instructed by MISO, THEN **ISSUE** public appeals to reduce demand per internal procedures. [□]

LBA
2. IF in declaration area, THEN **PREPARE** to shed load. [□]

4.3.8 Max Gen Event Step 3a - MISO Stakeholder Actions

GOP
1. IF requested by MISO to dispatch available capacity in Event Step 3a, THEN **DISPATCH** as follows: [□]
   A. **VERIFY** Generators in declaration area with de-rates from environmental restrictions. [□]
   B. IF approved waiver from government regulations, THEN **DISPATCH** available generation. [□]

4.3.9 Max Gen Event Step 3b - MISO Stakeholder Actions

LBA
1. IF in declaration area and notified by MISO to reduce Load during Event Step 3b, THEN **PERFORM** the following:
   A. REDUCE Load via LMM – Stage 2. [□]

Note [□]

- Reductions through LMMs are NOT precise to the MW.
- Determination of individual LMMs to be utilized will be managed at the LBA level.

   B. WHEN Load reduction actions have been implemented, THEN **NOTIFY** MISO via MCS. [□]

4.3.10 Max Gen Event Step 4a/b - MISO Stakeholder Actions

GOP/ MP
1. **REVIEW** Offers. [□]

GOP/ MP
2. **ENSURE** all available Emergency range and resources are offered. [□]

GOP/ MP

Note [□]

All Resources should be committed, producing energy or committed for reserves, except emergency ranges on Resources providing Regulating Reserves.

3. IF there are available Resources or capacity NOT being utilized, THEN **NOTIFY** MISO. [□]

4.3.11 Max Gen Event Step 5 - MISO Stakeholder Actions

LBA

Note [□]

In addition to ensuring load shed schemes are capable of implementation in a time frame adequate for mitigating the Emergency for load shed directed by MISO, LBAs are responsible to coordinate with TOPs for any load shed requirements, critical load evaluation in load shed schemes, and coordination including rotation of selected loads, with any other automatic load shed schemes such as Underfrequency and Undervoltage. The minimum MISO directed load shed per LBA should be maintained at all times, until load restore directions are provided by MISO.

1. **SHED** firm Loads per MISO issued Emergency Operating Instruction. [□]

LBA

2. **CONFIRM** actions taken with MISO RC via MCS Firm Load Shed Tool or verbally per SO-P-NOP-00-431 Communications Protocol For Operating Instructions. [□]

LBA

3. IF requested by MISO during Event Step 5, THEN **COMPLETE** Department of Energy (DOE) Form OE-417 as follows: [□]
   A. **COMPLETE** DOE Form OE-417 for actions taken to reduce Load via Load Management Procedures per NERC EOP-004-4 and SO-P-NOP-04 MISO Event Reporting Operations Plan. [□]
   B. **SUBMIT** completed DOE Form OE-417 to the following: [□]
      - DOE
      - NERC
   C. **FORWARD** a copy of the submitted DOE Form OE-417 to the following: [□]
      - Regional Entities
      - MISO @ RTOpsCompliance@misoenergy.org

4.3.12 Max Gen Event Downgrade/Termination - MISO Stakeholder Actions

LBA/ MP/ TOP/ GOP

1. **PERFORM** requests of MISO SM or designee to back out of each level. [□]

5.0 Definitions

1. **Reserve Margin** - The difference between Total Operating Reserves and the Operating Reserve Requirement.
2. **Constraint Stranded MW** - Resource MW that are NOT available to meet load due to congestion on the electric grid.
3. **Emergency Demand Response (EDR)** - Load reductions, behind the meter generation, and other demand resources that are available to reduce demand or increase generation in exchange for guaranteed recovery of costs associated with the response in accordance with Schedule 30 (EDR Provisions) of the Tariff.
4. **Load Management Measures (LMM) Stage 1** – Load management actions that can be taken to reduce demand to preserve or maintain Operating Reserves that are NOT included in EDRs or LMRs.
5. **Load Management Measures (LMM) Stage 2** – Load management actions that can be taken to reduce demand including voltage reductions and reducing Loads that, by contract, can NOT be interrupted until reserves are being or are expected to be depleted and energy from Emergency Offers by Market Participants are being or are expected to be depleted. These do NOT include EDRs or LMRs.
6. **Load Modifying Resource (LMR)** - These are either Demand resources or Behind the Meter Generation that have an obligation to reduce demand or increase generation during declared system emergencies
7. **Maximum Generation (Max Gen) Capacity Advisory** - Provides advanced notice of forecasted capacity shortage and will request stakeholder update data.
8. Max Gen Alert - Provides an early alert that system conditions may require the use of MISO’s generation Emergency procedures.
9. **Max Gen Warning** - MISO foresees or is experiencing conditions where all available economic Resources are committed to meet Load, firm transactions, and reserve requirements, and is concerned about sustaining required Operating Reserves.

10. **Max Gen Event** - MISO's forecasted or real-time energy demand and Operating Reserve Requirements within the MBAA (or sub-area due to a transmission constraint) can NOT be satisfied with Economic Maximum Limits of all available Resources; MISO issues a Max Gen Event due to a shortage of economic Resources.
11. **MBAA Sub-Region** - Sub-region may consist of a single LBA area, a group of LBA areas, or portions of an LBA area (for portions of an LBA area, a 1000 MW minimum threshold will generally be used).

6.0 References

6.1 NERC References

1. EOP-011-4 Emergency Operations
   - R2.2.1[Section 4.1.1 Step 1.]
   - R2.2.2 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.13 Step 1.]
   - R2.2.3 [Section 4.1.2]
   - R2.2.4 [Section 4.2.8 Step 5.]
   - R2.2.5 [Section 4.2.9 Step 2.]
   - R2.2.6 [Section 4.2.8]
   - R2.2.7 [Section 4.2.3 Step 6.][Section 4.2.4 Step 3.][Section 4.2.6 Step 6.][Section 4.2.7 Step 2.]
   - R2.2.9 [Section 4.2.13 Step 3.]
   - R2.2.10 [Section 3.1 Note after Step 1]
   - R5 [Section 4.2.1 Step 1.D.]
   - R6 [Section 4.2.5 Step 1.][Section 4.2.6 Step 1.] [Section 4.2.1][Section 4.2.13 Step 1.]
2. IRO-014-4 Coordination Among Reliability Coordinators
3. R1 [Section 4.1][Section 4.2]
4. TOP-001-6 Transmission Operations
   - R2 [Section 4.1][Section 4.2]

6.2 FERC References

1. MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff, Section 40.2.20

6.3 MISO References

1. SO-P-EOP-11 MISO Emergency Operating Plan
2. BPM-007 Physical Scheduling Business Practice Manual Section 16 – Capacity Resource Scheduling
3. SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
4. SO-I-EOP-00-006 Interchange Scheduling Operations during Emergency Conditions
5. SO-I-AOP-00-224 CTS Failure Modes
6. SO-I-NOP-00-404 Emergency Demand Response Implementation
7. SO-I-NOP-00-441 Operations Real-Time Event Resolution
8. SO-I-NOP-00-448 Event Communications Matrix
9. SO-I-NOP-00-462 Inadvertent Interchange Management
10. SO-I-NOP-00-481
11. SO-I-NOP-00-483 Reliability Coordination Conference Call
12. SO-P-EOP-00-004 Transmission System Emergency
13. SO-P-AOP-00-217 MISO and State Officials 24X7 Communication Protocols During Emergencies
14. SO-P-NOP-00-431 Communications Protocol For Operating Instructions
15. SO-P-NOP-00-449 Conservative System Operations
16. SO-P-NOP-00-455 Balancing Authority Operations
17. SO-P-NOP-04 MISO Event Reporting Operating Plan
18. SO-I-NOP-00-479 Purchasing and Selling Emergency Energy

Attachment 1 — Reserve Margin Example Calculations

1.0 Example 1: Projection for MBAA

Table 1: Calculation

Description	Value
MBAA Peak Load Forecast:	100,000
Operating Reserve Requirement:	2,410
Load plus Operating Reserve Requirement:	102,410
Available Economic Maximum in Area:	97,000
Constraint Stranded MW:	2,000
Available Economic Resources in Area:	95,000
Net Scheduled Interchange (NSI) into Area:	8,000
Reserve Margin = 95,000+8,000-102,410	+ 590
Reserve Margin (%) = (590/102,410)*100:	+ 0.6%

Assessment: Reserve Margin is forecasted to be +590 MW. Load plus Operating Reserve Requirement is met, however the Reserve Margin is less than 1500 MW. A Max Gen Alert declaration may be necessary.

2.0 Example 2: Projection for South Region

Table 2: Calculation

Description	Value
MBAA Peak Load Forecast:	30,000
Operating Reserve Requirement:	1,500
Load plus Operating Reserve Requirement:	31,500
Available Economic Maximum in Area:	29,000
Constraint Stranded MW:	1,000
Available Economic Resources in Area:	28,000
Net Scheduled Interchange (NSI) into Area (RDT NSI):	400
RDT Import Capability up to RDTL of 3,000	3,000
Reserve Margin = 28,000+3,400-31,500	-100
Reserve Margin (%) = (-100/31,500)*100:	- 0.3%

Assessment: Reserve Margin is -100 MW, meaning the South Region Load plus Operating Reserve Requirement is 100 MW short of being met. This means Load will be covered but the 1,500 MW Operating Reserve Requirement will not be. A Max Gen Warning or Event declaration may be necessary.

Attachment 2 — Maximum Generation Declaration Template

Maximum Generation Declaration Type: [Alert/Warning/Event]

The MISO RC is Declaring/Updating a Maximum Generation Alert/Warning/Event effective from [MM/DD/YYYY] [HH:MM] EST and [MM/DD/YYYY] [HH:MM] EST for the following entities:

[List the affected entities within the boundaries of the declaration by LBA. Include any constrained pockets within the declaration area with adequate generation that should be excluded from the Maximum Generation Emergency.]

The reason for the declaration is:
State the reason(s): Forced Transmission Outage, Forced Generation Outage, Higher than Forecasted Load, Above/Below Normal Temperatures, Loss of Import Interchange Schedules, Reduction in RDT limit, etc.

Members are to prepare for a Maximum Generation Emergency by performing the applicable MISO Member Maximum Generation [Alert/Warning/Event] Level Actions of SO-P-EOP-002 MISO Market Capacity Emergency procedure.

CTS Suspension: Attention Market Participants: CTS (Coordinated Transaction Scheduling) is Suspended as of [MM/DD/YYYY] [HH:MM] EST. Alternative scheduling methods should be utilized.

Projections (to LBAs and TOPs only):

- Peak hour for Area is Hour Ending [MM/DD/YYYY] [HH:MM] EST.
- Load plus Operating Reserve Requirement for Area: _____
- Amount of Available Economic Resources in Area: _____
- Imports into Area: _____
- Reserve Margin shortfall(-)/surplus(+) for Area: _____

1. Summary information (only) in the top of the OI Message/template will be communicated to MPs via the following:
   A. OI
   B. MISO public web site – Real Time Notifications Tab via OI View Real-Time Operations Updates at https://www.misoenergy.org/markets-and-operations/notifications-overview/

2. Completed OI message/template (summary & projections) will be communicated to TOPs, LBAs, BAs and neighboring BAs, and RCs as follows:
   A. OI
   B. RCIS
3. MISO will provide summary information to the following email exploder lists via OI message:
   - *MISO Alerts BA and TO
   - *MISO Alerts FERC, State Comm., RRO, Neighboring RCs and BAs
   - *RT Ops Notification

Attachment 3 — Load Management Update Form Example

Local Balancing Authorities report via MCS or phone to the RC Load reductions that would be available, time permitting, via Load Management should a Maximum Generation Emergency Event be implemented during the same time frame the Warning is effective. MISO will provide the expected notification time* for LBAs to assume when completing form.

Load Management may include but are NOT limited to public appeals, voltage reduction, and interruption of end use loads in accordance with applicable contracts, demand-side management, utility load conservation measures, and starting behind the meter generation*.

Load Management is separated into LMM – Stage 1 and LMM – Stage 2.

*Excludes Registered DRR Type 1 and DRR Type 2 Resources

Table 3: LBAs report the following estimated values:

LBA:	
Notification time for Load Management Measures (i.e. less than 4 hours)	
LMM Stage 1 available:	10
LMM Stage 2 available:	5
Total:	15
LBAs should list, LMM Stage 1 and LMM Stage 2 that are already or projected to be implemented at the Event time:	
LMM Stage 1:	100
LMM Stage 2:	0
Total:	100

Attachment 4 — Slice-of-System PPAs Load/Schedule Curtailment

1.0 Slice-of-System Power Purchase Agreements (PPAs) Curtailed Pro-Rata with Load in the Source Balancing Authority when Source Balancing Authority is in Emergency Procedures

1. PPAs in this category will continue to qualify as Planning Resources so long as the PPA only will be curtailed pro-rata along with load in the source Balancing Authority and only when the source Balancing Authority is operating under Emergency Procedures.
2. Under this situation, a PPA with a 1,000 MW export schedule from an external Balancing Authority with a 3,000 MW load will be curtailed pro-rata along with the load when the external Balancing Authority is operating under Emergency Procedures. That is, curtailment would take place three-quarters to firm load and one quarter to the firm schedule. This pro-rata treatment is triggered when MISO experiences emergency conditions at the same time as the external Balancing Authority.

2.0 Slice-of-System PPA in a Balancing Authority that Coordinates Planning Reserve Qualifications and Shares Emergency Responsibilities with MISO's Balancing Authority

1. In addition to the slice-of-system PPA treatment noted in category (B) above, slice-of-system PPAs can continue to qualify as External Resources under this category, and MISO and the external BA will share Load Shedding on a pro-rata basis in proportion to the load in the area under the Capacity Emergency, so long as the requirements of this category are met.
2. This qualification category has several requirements for the host BA:
   A. It must be in MISO's RC area.
   B. It must share Operating Reserves with the MISO BA.
   C. It must have a Seams Operating Agreement with MISO containing several features.
3. Seams Operating Agreement must specify the following:
   A. The host BA has established planning reserve processes and criteria similar to MISO's.
   B. Actions that will be taken by both entities – MISO and the host BA – during Emergency Procedures prior to implementing Load Shedding.
   C. BA responsibilities include:
      (1.) Submitting load estimates to MISO in a similar manner as submitted by other Load entities under Module E-1.

(2.) Providing generator testing data for all resources used to serve firm requirements of the host Balancing Authority.

(3.) Providing transparency to such resource plans in the form of a Fixed Resource Adequacy Plan, pursuant to Module E-1.

4. With these requirements in place, when both BAs have exhausted other emergency operating actions and are in a firm load shedding event, load shedding is shared on a pro-rata basis in proportion to the load in the area under the capacity emergency.

Example 1

If the load of an external BA in capacity emergency is 3000 MW and the load of the area in MISO in capacity emergency is 17,000 MW, then pro-rata load shed is 3/20 of the total for the external Balancing Authority and 17/20 for the area in MISO in the capacity emergency.

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5. This treatment is appropriate for BAs that meet the requirements indicated above because MISO can count on the fact that the external BA is planning and testing its resources in an equivalent manner to MISO, and is part of MISO's RC area and subject to emergency procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share its Operating Reserves with MISO during emergency conditions.

3.0 When MISO is in an EEA and the external BA with PPA is not, then MISO will determine if the PPA should flow or determine the curtailable MWs of the PPA.

1. LBA NET(Excess Capability) =
   Σ (LBA_online RTmw - LBA_online MaxObligation)
   - Where RTmw = Current RT MWs of Resource
   - Where MaxObligation = The lesser of a resource's Effective ICAP (capacity obligation) and their Real-Time Must Offer availability
2. Prior to any curtailments, MISO will contact the external BA by phone.
3. If the BA indicates that the curtailment will cause the BA to enter an EEA, then MISO will initiate SO-I-NOP-00-481.
4. If the BA indicates that the curtailment will NOT cause the BA to enter an EEA, then MISO will curtail any relevant schedule(s).

Attachment 5 — Additional Information

1.0 Max Gen Emergency

1. MISO may call for a Max Gen Alert, Warning or Event, or EEA level prior to the actual forecasted start time of such Alert, Warning, Event or EEA level.
   A. The purpose of this would be to communicate forecasted conditions that meet the criteria of these levels, as well as to provide notice of certain implementation steps which require longer notifications times.
   B. An example would be an LMR which has a 4-hour notification time, requiring implementation instructions to be sent prior to the actual start time of the Event, or EEA.
   C. Due to the dynamic nature of the Bulk Electric System (BES) these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Alert, Warning, Event or EEA as conditions warrant.
   D. At the Max Gen Alert level, Emergency Pricing Tier 0 is in effect until termination of the Alert or increasing Max Gen level to Warning level or higher.
2. Max Gen Warning
   A. EDRs may also be registered as LMRs in Module E. If a MP has decided to offer in all or part of their resource as an EDR for an operating day, the MP should reduce the availability of that resource as an LMR in the DSRI Tool for all 24 hours of the same operating day by the maximum MW amount offered in for that resource as an EDR. In addition, if an MP has implemented any resources voluntarily, which are registered as an LMR, the MP should adjust the availability of that resource in the DSRI Tool.
   B. Tier 1 prices are in effect from Max Gen Warning until an Emergency Event Step 2a, when Tier 2 prices are implemented. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.
3. Max Gen Event
   A. MISO will implement Emergency Pricing Offer Tier 2 during Step 2a of an Emergency Event. This is an ex-post ELMP pricing change and does NOT affect system commitment or dispatch. Emergency Pricing will be utilized as necessary on an LBA basis.

Attachment 6 — Maximum Generation Emergency Overview

The following is an overview of Max Gen Emergency actions and should be used for reference only during an actual event.

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Declaration	Send OI Declaration message	Prepare to implement this procedure and follow internal procedures for emergency conditions
	Declare Conservative System Operations	Follow instructions per Conservative System Operations procedure and declaration
	Increase STR Default if System Wide or STR MSSC if North/Central or South Region	
Alert	Identity available Module E Resources	MPs communicate available Module E Resources
	Identify non-firm Export Schedules	MPs update energy interchange transaction E-tags of Capacity Resources
	Implement Emergency Pricing - Tier 0	LBA/TOP provide potential exclusion of constrained pockets within the declaration area
	Raise transfer capability or make constraint stranded generation available	TOPs coordinate with MISO RC to identify potential reconfiguration options
	Request MPs/LBAs ensure accuracy of LMM/ LMR availability and Self Scheduled values	LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS/ DSRI Tools
	Send LBAs LMM survey	Affected GOPs communicate capacity limited facilities to MISO and update limits and offers

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Warning	Implement Emergency pricing - Tier 1	
	Suspend CTS	
	Determine EDR availability and MW amounts	MPs update EDR availability and MW amounts
	Obtain updated MW amounts of relief available via Load Management Form in MCS	LBAs update LMM availability via Load Management Form in the MCS
	Review LMR availability using MCS-LMR tool	MPs ensure LMR availability data is correct in the DSRI Tool
	Schedule available Module E Resources into declaration area	As directed by MISO, MPs schedule available Module E Resources into the declaration area
	Curtail Export Schedules as required	
	Instruct TOPs to implement reconfiguration options	As directed by MISO RC, MPs implement reconfiguration options
Event Step 1a	Commit AME resources	As directed by MISO, LBAs/GOPs/MPs start AME Resources
Event Step 1b/EEA1	Declare EEA1	MPs review Offers and ensure all available Emergency ranges and Resources are offered
	Activate Emergency Maximum Limits	
Event Step 2a/EEA2	Declare EEA2	
	Implement Emergency pricing - Tier 2	
	Instruct Load to be reduced via LMMs - Stage 1 and LMRs	As directed by MISO, LBAs reduce load via LMM - Stage 1
	Implement LMRs	MPs implement LMRs via DSRI Tool
Event Step 2b	Commit EDR Resources	As directed by MISO, MPs commit EDRs

Table 4: Maximum Generation Emergency Overview

Level	MISO Major Actions	Stakeholder Major Actions
Event Step 2c	Implement Emergency energy purchases	LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings
	Instruct LBAs to issue Public Appeals	
		LBAs in defined Event area shall prepare to shed Load
Event Step 3a	Notify affected GOPs with Generator de-rates to request waivers	Affected GOPs dispatch de-rated Generators with waivers from government regulations
	Implement spinning and supplemental reserves	
Event Step 3b	Elevate identified Priority 6-NN tags	
	Instruct Load to be reduced via LMMs - Stage 2	Affected LBAs reduce load via LMM - Stage 2
Event Step 4a	Implement Reserve Call from CRSG	MPs review Offers and ensure all available Emergency ranges and Resources are offered
Event Step 4b	Implement Emergency energy purchases from neighboring BAs (Operating Reserves)	
Event Step 5/EEA3	Declare EEA3	
	Issue Emergency Operating Instruction to shed load	LBAs shed load per MISO and confirm action via MCS Firm Load Shed Tool
	Set LMPs and MCPs to the VOLL	LBAs review OE-417 filing requirements

Attachment 7 — UDS Operator Actions During MISO Market Capacity Emergency Conditions

- If a North/Central declaration is in place and a South declaration is subsequently implemented, Increase STR Default Values as specified in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure.
- Implementation of these steps are outlined in SO-I-EOP-00-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing
- Does not include Max Gen Event Downgrade/Termination Actions as noted in section 4.2.1.14
- * STR RPE & STR Default Values are specified in SO-I-EOP-001 Utilizing Emergency Ranges and Emergency and VOLL Pricing procedure

SO-P-EOP-00-002 MISO Market Capacity Emergency - UDS Operator Actions

		Increase STR RPE MSSC Default Values for Zone 8 (South) if not done in previous declaration*	Increase STR RPE MSSC Default Values for Non-Zone (N/C) if not done in previous declaration*	Increase STR Default Values for System Current (System Wide) if not done in previous declaration*	Implement Emergency Pricing Tier 0	Implement Emergency Pricing Tier 1	Activate Emergency Limits	Implement Emergency Pricing Tier 2	Check Is VOLL Price Enforced in EMD
System Wide Declaration Level	Capacity Advisory	■	■	■					
	Max Gen Alert	■	■	■	■				
	Max Gen Warning	■	■	■		■			
	Max Gen Event Step 1a	■	■	■		■			
	Max Gen Event Step 1b	■	■	■		■	■		
	Max Gen Event Step 2a and above	■	■	■			■	■	
	Max Gen Event Step 5	■	■	■			■	■	■
North/Central Declaration Level	Capacity Advisory		■						
	Max Gen Alert		■		■				
	Max Gen Warning		■			■			
	Max Gen Event Step 1a		■			■			
	Max Gen Event Step 1b		■			■	■		
	Max Gen Event Step 2a and above		■				■	■	
	Max Gen Event Step 5		■				■	■	■
South Declaration Level	Capacity Advisory	■							
	Max Gen Alert	■			■				
	Max Gen Warning	■				■			
	Max Gen Event Step 1a	■				■			
	Max Gen Event Step 1b	■				■	■		
	Max Gen Event Step 2a and above	■					■	■	
	Max Gen Event Step 5	■					■	■	■
Single Region (North or Central) Declaration Level	Capacity Advisory								
	Max Gen Alert				■				
	Max Gen Warning					■			
	Max Gen Event Step 1a					■			
	Max Gen Event Step 1b					■	■		
	Max Gen Event Step 2a and above						■	■	
	Max Gen Event Step 5						■	■	■

Figure 1: UDS Operator Actions During MISO Market Capacity Emergency Conditions

Attachment 8 — Summary of Market Capacity Emergency Procedure Steps

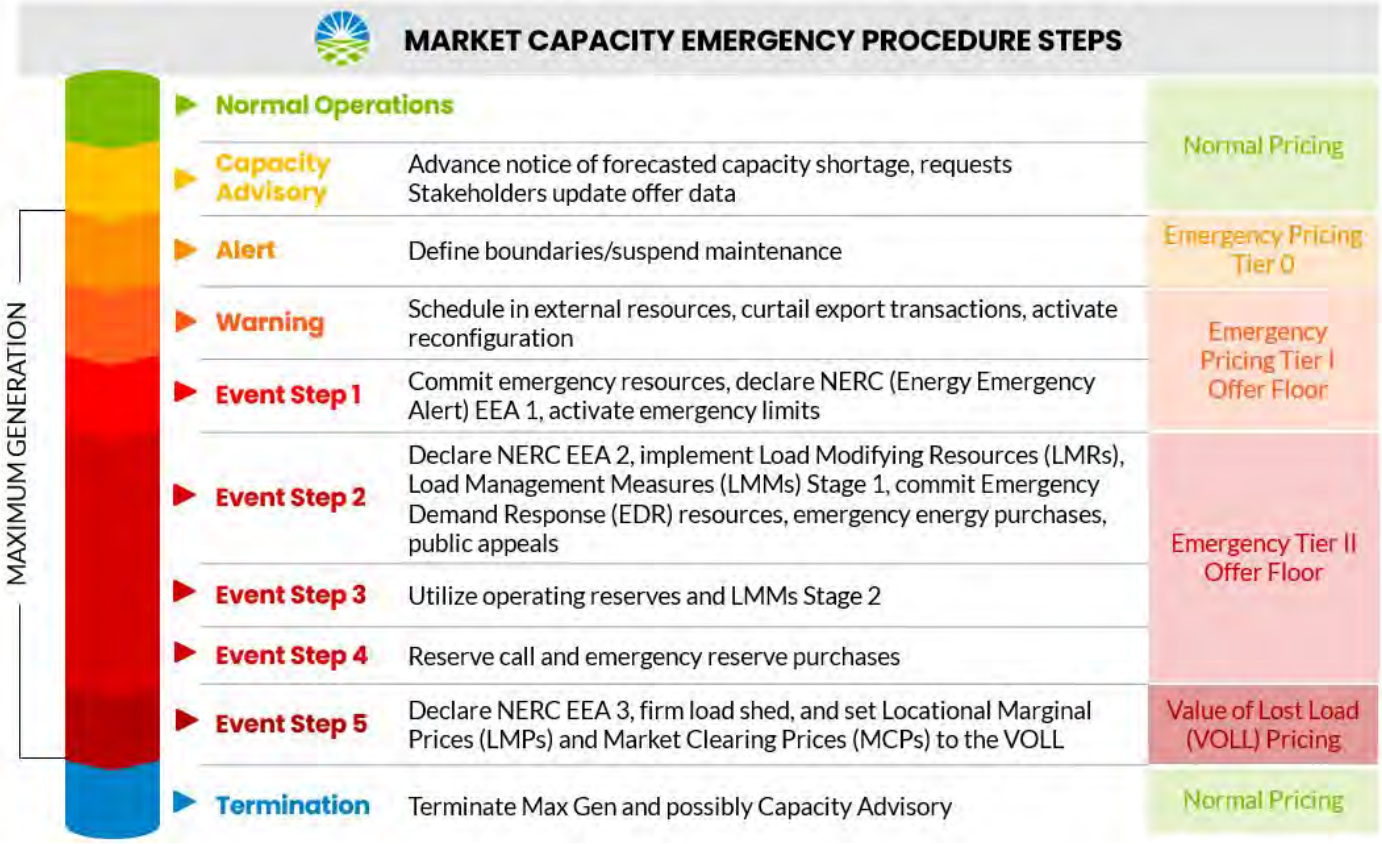

Figure 2: Market Capacity Emergency Procedure Steps

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 34

Ramey MISO Comments

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference Regarding	**)**	
The Challenge of Resource	**)**	**Docket No. AD24-11-000**
Adequacy In Regional Transmission	**)**	
Organization and Independent	**)**	
System Operator Regions	**)**	

COMMENTS OF TODD RAMEY
ON BEHALF OF
MIDCONTINENT ISO INC.

I. INTRODUCTION

MISO's Resource Adequacy Challenge

The electricity grid today is facing a significant transition at a pace never seen before. To ensure that our nation's bulk electric system remains reliable, it is important to recognize and stay ahead of the challenges and trends that are impacting electricity production and consumption. Today, the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth. The ultimate responsibility for resource adequacy in the MISO region lies with its member states and other Relevant Electric Retail Regulatory Authorities ("RERRAs"). MISO works closely with stakeholders, including the states, to provide market tools and information necessary to support regional transparency that, in turn, support and inform resource investment decisions relating to resource adequacy. MISO has made significant advancements over the past several years enhancing its market price signals, improving resource accreditation, assessing expected resource needs and improving its generation interconnection queue processes and tools.

The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet load for their area and states having jurisdiction over resource adequacy decisions. This is distinct from some other RTOs, which rely more heavily on competitive markets to shape electric resource adequacy needs. A combination of state and federal policies and consumer demand for carbon free energy has resulted in rapid growth of wind and solar energy accompanied by the retirement of many coal and natural gas power plants. While weather-dependent resources like solar and wind are being added in large numbers and provide many benefits, including lower electricity production costs than natural gas or coal as well as

the lack of carbon emissions, they typically do not provide the same 24/7 availability, flexibility, and duration attributes as the retiring power plants they are replacing. For example, MISO has experienced 11 wind droughts since 2020, including one lasting 40 consecutive hours. Similarly, solar output is dramatically reduced in overcast or cloudy weather conditions, as often occur in winter storms, and output is virtually zero in the overnight hours. While energy storage technology is beginning to integrate into MISO's markets, we are not expected to see the volume of such resources be deployable in order to help support meeting resource adequacy and reliability needs for several more years. MISO works collaboratively with the states, utilizing its regional perspectives and insights, to ensure they have an understanding of evolving system needs and conditions. This is accomplished, in part, through MISO's work on long-term load forecasting, resource accreditation, and Futures Planning Scenarios.

MISO has a healthy partnership with the Organization of MISO States ("OMS"), an independent organization with its own dedicated staff representing the collective interests of state and local utility regulators in the MISO region. Many of the changes MISO has implemented were made possible due to their collaboration and role in communicating and facilitating the insights of the RERRAs in the MISO region.

By coordinating with states and other RERRAs, MISO is able to develop a range of expected outcomes we call Future Planning Scenarios. MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW[1] due to the operational characteristics of these new resources. Emerging technologies with the needed characteristics, such as longer-duration battery storage and small modular nuclear reactors, hold great promise in the future but are likely years away from grid-scale viability.

MISO also creates significant value for the region, which is quantified in the MISO Value Proposition study.[2] While resource development is critical, we must also recognize that the existing electric transmission infrastructure is vital in supporting resource adequacy and is a significant value driver by reducing the overall resource obligation to each load serving entity in the MISO region. The largest value driver in the MISO Value Proposition is the savings associated with the reduction in reserve margin needed to meet resource adequacy targets. Our work to maintain reliability, administer wholesale markets and conduct transmission planning on a regional scale generates substantial benefits. In 2024 alone MISO created approximately $5.1 billion in savings for the region, and over $50 billion since 2007. Ultimately, this results in lower costs to consumers. To continue driving high levels of value and low costs, the transmission system needs to keep pace with the location of the resources that will be developed to provide the energy that will be

[1] This projection is found in MISO Future 2A found in the MISO Futures Report developed in November 2023. More information on MISO Futures Series 2A Report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf

[2] MISO's Value Proposition is an annual study that breaks MISO's business model into recognized categories of benefits and calculates a range of dollar values for each defined category. In 2024, MISO's annual benefit was valued at $5.1 billion. More information available at https://www.misoenergy.org/meet-miso/MISO_Strategy/miso-value-proposition/

needed in future years, and to provide the connectivity to move energy across the generation fleets to population centers.

MISO's region, like most of the country, is also experiencing changing weather patterns, including more frequent occurrences of extreme weather, particularly winter storms affecting large areas of the country. These extreme weather events create challenging operating conditions, with high demand for electricity sometimes accompanied by reduced solar or wind output and, in some instances, challenges with adequate fuel supplies for natural gas and coal power plants. This highlights the need for a diverse electric generation fleet and a robust transmission system to move energy over long distances.

Finally, demand for electricity is growing at an accelerated pace. Over the last few decades, we have experienced growth in electrification through electronic devices, smart home products, and electric vehicles, but minimal growth in electric peak demand, largely due to increasing energy efficiency. Looking ahead, however, we expect much stronger growth from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy hungry data centers to support artificial intelligence. In fact, based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ("CAGR").[3] This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken.

This combination of factors significantly increases operational challenges, uncertainty, and reliability risks to the electric grid. This, in turn, creates significant economic and security risks for our nation. If electricity production and delivery from all sources cannot keep up with growing demand, then the planned growth of manufacturing, artificial intelligence, and data centers cannot occur. A timely and coordinated approach is necessary if we are to continue meeting the nation's need for reliable and low-cost electricity. MISO is committed to meeting this challenge in coordination with our states, members and stakeholders as articulated by our Reliability Imperative effort.

MISO Reliability Imperative

The electric industry in general, and the MISO Region in particular, are changing in significant ways. In the past, MISO maintained a reliability standard significantly above the "one day in ten years" that is the minimum acceptable rate of reliability. However, as MISO has been emphasizing since 2022, we have seen resource margins and reliability standards decline due to policy drivers, aging resources and financial incentives. Today, the MISO region is meeting the 1:10 minimum, and we are working to maintain at least this level going forward.

Looking ahead, we have four tools for maintaining reliability: 1) maintain existing generation, as needed for resource adequacy; 2) enhance the utilization of demand response; 3) build new generation and transmission when existing resources are

[3] More information on the current trajectory of peak load growth can be found in MISO's Long-Term Load Forecast published in December 2024 and found here https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf

unavailable to support new load growth; and 4) be prepared for more frequent instances of targeted load shed to ensure system reliability during extreme operating conditions.

The sharing of responsibility between MISO, Load Serving Entities ("LSEs"), and RERRAs is needed to address the challenges of rapid fleet change, increased frequency and severity of extreme weather events, and other factors that pose a threat to reliability in the MISO Region. MISO calls this shared responsibility the 'Reliability Imperative.' The word 'imperative' is appropriate for several reasons. First, the work we are doing is not optional—to maintain system reliability, we must respond to the unprecedented change we and our members face. Second, this work cannot be put off for months or years—much of it has long lead times, so we need to act now. And third, our stakeholders are counting on us—regulatory agencies, utilities and other entities are looking to MISO to identify problems and find solutions."[4]

MISO published a report in December 2020 that documents these trends and explains why these trends create a Reliability Imperative for the region.[5] MISO's response to these issues focuses on four pillars: (1) Market Redefinition; (2) Operations of the Future; (3) Transmission Evolution; and (4) Systems Enhancements (formerly called Market System Enhancements). Pillars #1 and #3 profoundly affect resource adequacy.

As explained by MISO's Chief Executive Officer, John Bear: "The industry's longtime reliance on conventional baseload power plants is declining sharply, driven by economic factors and consumer preferences for clean energy, among other things. Meanwhile, the grid is becoming increasingly reliant on wind and solar resources that are available only when the wind is blowing or the sun is shining. To be sure, there are upsides and opportunities associated with these trends. But the changes we are seeing also pose a host of complex and urgent challenges to electric system reliability in the MISO Region. Utilities, states, and MISO all have roles to play in addressing these challenges."[6]

Pillar #1: Market Redefinition

MISO's market design guiding principles are an important guide to evaluating and developing market enhancements that have been used as a foundation for conducting the Planning Resource Auction (PRA). MISO's Market Design Guiding Principles are as follows:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity,
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector, or location,
- Develop transparent market prices reflective of marginal system cost, and cost allocation reflective of cost-causation and service beneficiaries,

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[4] See MISO's Response to the Reliability Imperative (December 2020), available at https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf.

[5] More information on MISO's Reliability Imperative at https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[6] MISO's Response to the Reliability Imperative, found here https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative%20FINAL504018.pdf

- Support Market Participants ("MPs") in making efficient operational and investment decisions, and
- Maximize alignment of market requirements with system reliability requirements

All aspects of MISO's resource adequacy construct have been and are being evaluated to better ensure energy readiness under this Reliability Imperative. Specific efforts in this area include providing a longer-term and deeper assessment of system needs across all hours of the year, including required capabilities such as flexibility, shifting to verifying sufficient generation adequacy across all hours of the year, improving how resources are accredited, ensuring that prices accurately reflect market conditions, especially during emergencies, and developing market products that provide the right incentives for resources to maintain system reliability The initiatives in this category aim to ensure that resources with the types of capabilities and attributes the system needs will be available in all 8,760 hours of the year. Hence, MISO has moved from an annual auction to a seasonal one. This is important because as noted above, the region is increasingly facing reliability risks outside of the summer peak-load months that historically posed the greatest challenges. On the supply side, MISO has improved accreditation efforts, to reflect the availability of resources during hours in each season exhibiting low capacity margins.

On the demand side, MISO determined that the implementation of a Reliability Based Demand Curve ("RBDC") (sometimes referred to as a "sloped demand curve") in the PRA will support MPs by establishing more efficient capacity prices based on market fundamentals, where the marginal reliability benefit of the last MW procured is equal to its marginal cost.

With better price formation and improved capacity accreditation, MPs can make better informed operational, retirement, and investment decisions, and the PRA will significantly improve alignment of market requirements with system reliability requirements.

Pillar #3: Transmission Evolution

Over the last several years, MISO has approved over $30 billion in new transmission lines through a Reliability Imperative initiative called Long-Range Transmission Planning, or LRTP, with more expected in the coming years. These projects are projected to have a benefit-to-cost ratio of approximately 2.6 to 1 and will substantially improve electric transfer capabilities and enable the electric reliability and associated economic growth being planned across the nation.

Intermittent resources such as wind and solar work with the transmission system very differently than conventional power plants. For this reason, the ongoing trend of conventional resources retiring from service as intermittent renewables continue to grow poses significant challenges to the reliability of the transmission system in the MISO region. These challenges are framed up in MISO's Renewable Integration Impact Assessment work. Fortunately, MISO can leverage its large footprint and resources to ease some of the challenges. One of the keys will be transmission projects that support these new resources in the region. LRTP is designed to assess the region's future transmission needs, starting from a base of the utility and state plans on where to site and

build new resources. LRTP does not replace other transmission-planning efforts that have long existed at MISO, such as the annual studies contained in the MISO Transmission Expansion Plan ("MTEP"). LRTP will coordinate closely with those efforts, and it will also be a transparent and cooperative part of the MISO stakeholder process.

LRTP is a comprehensive "transmission roadmap" that will identify and drive investments in transmission projects addressing all needs of the region as the resource fleet continues to evolve. The roadmap will be updated as needed to align with evolving resource fleets and business plans, state energy/environmental policies, and other dynamic factors that affect the region's transmission needs. As solutions are identified through LRTP, they are moved into the ongoing MTEP process for final approval by MISO management and Board of Directors.

Recent Accomplishments

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission ("the Commission") approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new, four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification, and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of LRTP projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to establish appropriate capacity clearing prices based on the reliability risk of clearing MWs above or below the one-day-in-ten reliability standard. This lack of a "warning signal" when reserve margins decline can mask an imminent shortfall — as occurred with the 2022 PRA. Efficient capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design an RBDC that will improve price signals in the PRA. Full implementation began in the 2025 PRA, with first year results demonstrating that the refined PRA is working as designed.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to

lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

Queue Reforms: MISO has instituted several reforms to speed up the queue cycles, including a cap on the number of projects that can enter the queue in a given cycle, and is working on several technological enhancements and process improvements to eventually get to a one-year queue cycle. In the interim, an Expedited Resource Addition Study, or ERAS, process was recently submitted to the Commission for consideration. If approved, this process would provide a temporary framework, sunsetting by the end of 2028, for the accelerated study of electric generation projects that are required to address urgent resource adequacy and reliability needs

MISO's extensive analysis and operational experience make it clear that no single electric generating resource, transmission line, process improvement, emerging technology, or other solutions will solve all our challenges. Addressing our nation's future electricity needs requires a multi-faceted and coordinated approach that leverages all of these tools.

Next Steps

The operational challenges and reliability risks of the MISO region are largely mirrored across the country. To address them, we need to take several important steps to turn around the decline in available energy and expedite the construction of new electric generation and the transmission lines necessary to move necessary energy from where it is produced to where it is needed. Specifically:

- Ensure that states and utilities have the information they need to make prudent electric resource decisions to support resource adequacy.
- Continue to improve the loss-of-load modeling effort which underpins the planning reserve margins determined to meet the reliability standards. This includes better representation of all resources' availability and outage patterns, continued effort to model load growth and variability, and incorporate correlated impacts across both supply and demand.
- Let reliability needs help inform the pace of retirement of existing electric generating resources. Having the right mix of resources on the system means that we don't have to choose between decarbonization and reliability.
- Continue developing new resources at a rapid pace. Streamline the approval of new electric generation and transmission projects, and work to mitigate the regulatory, supply chain, and workforce challenges that can hinder development of these projects.
- Leverage an "all of the above" approach that includes a mixture of solar, wind, natural gas, storage, emerging technologies, and transmission to achieve reliability.

- Continue reforms, like MISO's ERAS and Demand Response and Emergency Resource reforms, that enable the more effective and efficient utilization of existing resources and capabilities.
- Continue exploring Distributed Energy Resources ("DERs") as a potential additional tool to address resource adequacy and reliability challenges.
- Support and encourage continuous interregional collaboration on future transmission needs and operational protocols that maximize the use of the existing system.

II. PANEL 1: THE RESOURCE ADEQUACY CHALLENGE IN RTOs/ISOs

***Question 1*: What is the current state of resource adequacy across RTO/ISO regions?**

a. ***Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?***

MISO has seen surplus capacity margins declining over the last several years. When considering capacity margins, MISO particularly views the level of "accredited capacity" as the key factor to assess resource adequacy. It is essential to consider the accredited value of capacity, rather than the simple "nameplate" value, since accredited is the only value that can be relied upon to ensure that energy will be provided by a resource during the periods of greatest need. The decline in accredited capacity is primarily due to the retirement of existing dispatchable generation, while new capacity additions have generally been non-dispatchable resources with lower accreditation values.

The reduction in reserve margin is a significant concern. MISO has continued to work closely with the states and stakeholders to ensure that the region remains, in excess of the 1-day-in-10-year Loss of Load Expectation (LOLE) reliability standard. Over the past several years, MISO has (1) initiated reforms to improve capacity accreditation to better signal the value of needed resource additions, (2) converted to a seasonal capacity construct to better reflect differing seasonal operating needs and characteristics, (3) continued collaboration with states with a transparent survey of future capacity expectation to inform policy makers, (4) provided longer term assessment of the resource mix changes in our Regional Resource Assessment ("RRA") to further inform long term policy and investment decisions, and (5) enhanced risk modeling to better align between the manner in which seasonal risk is being evaluated and resources are being accredited to meet the designated need.

The 15 states in the MISO region take their rights and responsibilities towards resource adequacy seriously and the MISO capacity market recognizes that. The OMS has supported developments in pursuit of MISO's Reliability Imperative. The Reliability Imperative was developed in 2020 to address urgent and complex issues facing the grid and contains four pillars: Market Redefinition, Operations of the Future, Transmission Evolution, and System Enhancements. Collaboration between MISO and the OMS allows for a reliable grid amongst changes in the diverse MISO footprint. MISO provides transparency in expectations of future resource adequacy plans through Futures

Modeling, the RRA, and the OMS-MISO Survey. We are confident that the footprint will continue to be resource adequate in the near and longer term.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA[7] is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. Another is the OMS-MISO Survey. While RRA and the OMS-MISO Survey are similar in some ways, there are some key differences that provide resource planners. The RRA is a 20-year outlook based on publicly announced resource plans and policy goals. It projects that members and states will add new generation capacity at an unprecedented rate of 17 GW/year (compared to the average of 4.7 GW/year added over the last decade) for the next 20 years to reliably achieve their publicly announced resource plans and policy goals.[i] Accordingly, the RRA projects capacity surpluses in 2030 and beyond. In contrast, the OMS-MISO Survey is more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 (which did not materialize) to capacity surpluses through 2029. Again, these divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions.

MISO is confident that its current capacity construct is the best tool to identify, analyze, and address resource adequacy issues in the MISO region. The MISO capacity construct works because:

- The Reliability Imperative describes the shared responsibility between LSEs, states and RERRAs, and MISO to maintain a reliable grid.
- MISO respects states' rights toward resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. In fact, most LSEs engage in some form of integrated resource planning that is used to meet these obligations and filed with their appropriate RERRA.
- This type of resource planning makes sense because investments in generation have expected lifetimes of well over 30 years, so asset owners require some level of confidence that these builds can recover their capital costs.
- MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO and MISO members on where resource adequacy conditions are trending. From this state-specific information, MISO conducts analyses that are made public around the different types and amounts of resources necessary to meet the reliability standards being imposed by NERC.
- The "1-day-in-10-years" LOLE criterion established by NERC and codified in our Tariff has served the region well and sets the benchmark used to design an adequate system.[8] MISO translates this LOLE criterion into an amount of planning reserve margins that LSEs are obligated to have.

[7] More information on MISO's 2024 Regional Resource Assessment can be found here https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf

[8] MISO's reply to question 6 below recognizes that other reliability metrics on resource adequacy may be of use in the future.

- MISO conducts its prompt PRA to inform LSEs and RERRAs of resource adequacy trends in MISO. A one year clearing price is akin to the role of energy prices in MISO's real time market; well over 95% of an LSE's obligation for energy is procured in the day-ahead market, the real time market is an imbalance market but real time prices can drive Power Purchase Agreements ("PPAs") and expected day-ahead prices. Well over 90% of the obligations of LSEs in any PRA are met with owned or contracted for resources, which is consistent with integrated resource planning processes of the LSEs.
- The PRA has, since inception, served as a residual capacity auction, giving those LSEs that are long or short an opportunity to sell or buy, but the PRA is a voluntary auction.
- The PRA is conducted a few months before the beginning of the Planning Year, and conducted on a seasonal basis to recognize the differences in risks across the seasons.
- The prompt nature of the PRA significantly reduces uncertainty around where demand is heading and which resources are available to meet that demand for the upcoming Planning Year.
- With the adoption of the RBDC design, capacity prices are more reflective of the reliability contributions of the amount of MWs cleared, but they can still vary based, in part, on the amount and offer prices of supply.
- MISO's Value Proposition, highlighted above, shows the savings MISO members achieve in reduced reserve margins while maintaining the 1-in-10 LOLE through the risk sharing pool they participate in.

MISO's recent shift to a seasonal capacity market with seasonal accredited capacity better reflects extreme weather conditions that have become more prevalent. These weather conditions affect both the seasonal peak demand and the available seasonal supply. In addition, the seasonal construct better reflects the seasonal planned & forced outage patterns of supply. The recent implementation of the RBDC reflects the contributions to reliability incremental MWs can add to the system. On the supply side, resources are being accredited based on availability during all times of need, across all seasons (Schedule 53, seasonal accredited capacity resources).

Question 2: Given load growth and generation forecasts, what are your resource adequacy challenges going forward?

MISO's challenge is ensuring that the new generation in the region is able to keep pace to reliably meet the expected load growth while older generation resources with strong reliability attributes continue to retire. Existing dispatchable generation with flexibility attributes, such as natural gas and coal, is retiring rapidly and is being replaced by weather-dependent generation such as wind and solar that does not have the same 24/7 availability. Carbon-free resources that can provide the needed attributes – such as longer-duration battery, hydrogen, and small modular nuclear – is likely several years away from grid-scale viability.

This gap between dispatchable generation and highly accredited carbon-free replacements caused capacity shortfalls in the 2022/2023 planning year, being short in the North subregion by 1,230 MWs. Additionally, the extreme price volatility in the vertical

demand curve auctions may have eroded confidence in the capacity construct by sending inefficient price signals, but this has been addressed with RBDC. Changes to the resource adequacy construct highlighted in the previous question, and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader system reliability attributes. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute. System adequacy is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance. Flexibility is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability. System stability is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability. No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize, and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.[9]

<u>Question 3</u>: How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?

MISO's resource adequacy objectives are formally communicated through the resource planning obligations on LSEs. As a general matter, the responsibility to assure resource adequacy belongs to the states. MISO runs an annual PRA to provide a tool for LSEs to complement their long-term resource adequacy procurement decisions under the supervision of their state regulatory authority.

MISO further supports adequacy objectives with state public policy requirements by assessing, analyzing, and providing states and other RERRAs with information on where resource adequacy conditions are moving. MISO uses the OMS-MISO Survey and RRA

[9] More information on the MISO Attributes Roadmap can be found here https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

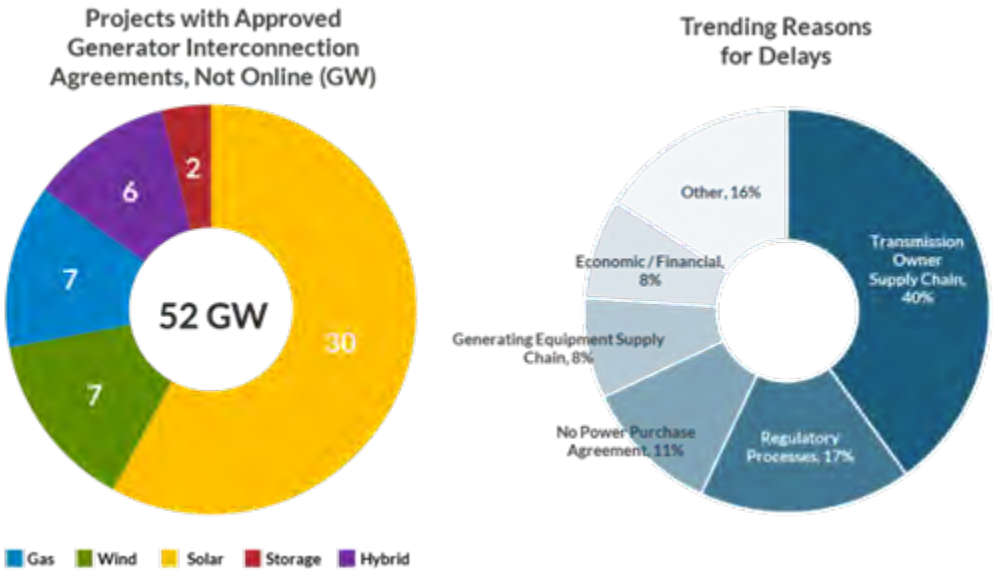
studies to highlight the needs of the entire footprint on a macro level. MISO is responsible for facilitating residual capacity transactions throughout the footprint through the PRA. Since MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously. MISO respects states' rights towards resource adequacy and acknowledges that LSEs have an obligation to serve their end-use customers. As a result, MISO takes the resources offered into MISO's markets as given and procures resources to meet the margin requirements at least cost. This analysis is highlighted in the OMS-MISO survey and RRA studies. MISO has the obligation to translate the 1-in-10 LOLE requirements into planning reserve requirements and to facilitate residual capacity transactions through the PRA.

***Question 4**: What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?*

There is a combination of factors that contribute to delays in the construction and interconnection of new resources on the grid. This includes delays in the process to provide generation interconnection agreements to new generation resources and delays in those resource with generation interconnection agreements getting to commercial operation. MISO is taking significant steps to improve the queue processing delays and provide transparency to the delays in commercial operation dates to help facilitate identification of potential solutions to the problem.

The current reality is that study cycles are taking 3+ years in MISO's Generator Interconnection Queue process. This is, in part, due to the dramatic increase in the number of project submissions in recent years, which does not support the region's needs. Once a project receives a Generator Interconnection Agreement ("GIA") and is approved for construction, there may be construction delays due to supply chain challenges, regulatory hurdles, and other issues. More than half of all delays are attributable to transmission owner supply chain issues and regulatory processes. The next largest factor is lack of PPAs.

Figure I.A.[10]



An expedited study process that balances the responsibility for providing grid reliability and resource adequacy in the MISO region between MISO, LSEs, and the states can solve many of these problems. Projects that prove they have resolved the aforementioned barriers to success (such as funding, citing and permitting, etc.) should be able to enter a separate process to bring new generation online in the short-term to meet resource adequacy and reliability needs. This is especially needed in light of load growth and data center build out. Currently, data centers do not have a process in place to come online as quickly as the market would require. An expedited queue process can handle expected load growth, such as this, during a time when dispatchable resources are expected to leave the region at a rate much higher than accredited capacity can keep up with.

MISO found internal improvements to reduce study times as well. MISO's recently approved queue cap proposal will ensure a more manageable volume of projects, driving lower study times. Additionally, MISO's implementation of Suite of Unified Grid Analyses with Renewables ("SUGAR") software utilizes advanced data and analytics using machine learning and artificial intelligence to create reliable and informed planning and operations, as well as significantly lower study and modeling times. Full implementation of SUGAR will take study times from 3+ years to under 1 year. But it will likely take about 4 years for full implementation of SUGAR. Allowing for an accelerated study process for certain projects will address queue backlog until the entire queue process is improved to a 1-year timeframe.

To address supply chain issues MISO encourages long-term stability and certainty in federal energy policy. This will promote investments that are discouraged by volatility.

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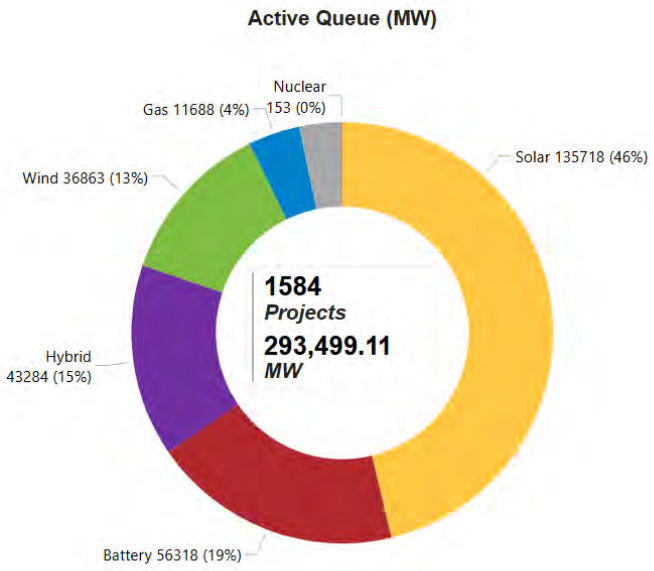
[10] Figure I.A. Compares 52 GW worth of generator interconnection projects with an Approved Generator Interconnection Agreement that have not come online with a breakdown of reported developmental delays. As of March 26, 2025.

Citing and permitting issues certainly causes delays, but these issues are not very different than they were 3-5 years ago. Generally, these factors should be addressed and resolved prior to entering the interconnection queue.

As a transmission planning organization, MISO is resource neutral and does not consider resource adequacy contributions during the interconnection process.

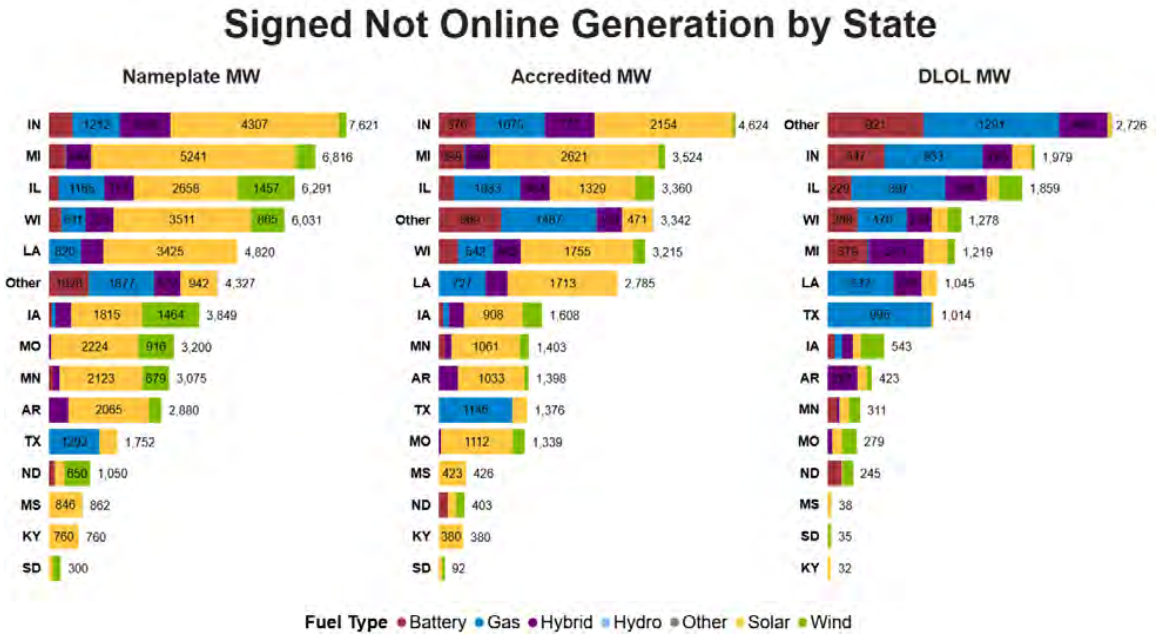
The current composition of resources in MISO's generation interconnection queue is illustrated in Figure I.B. This breakdown of capacity in the queue supports the points made in our answer to question 2 above about the potential looming shortage of broader system reliability attributes, being analyzed in the Attributes Roadmap report. Figure I.C. illustrates a breakdown of projects with signed GIAs that are not yet online.

Figure I.B.[11]



[11] MISO's Active Generator Interconnection Queue as of May 15, 2025.

Figure I.C.[12]



***Question 5*: Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?**

In the long-term, an emerging gap between installed capacity[13] and accredited capacity[14] is a high priority. The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years.[15]

Figure I.D. shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources, published in Series 1A MISO Futures Report. As the charts show, the region's level of *installed* capacity – the blue line – is forecasted to increase due to the many new resources – primarily wind and solar – that utilities and states plan to build in that 20-year time period. But because those new wind and solar resources have significantly lower accreditation values than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity – the red line – is forecast to decline by 2042. With each Future increasing the total retirement of highly accredited thermal resources, this negative net change is more pronounced across Futures: Future 1A projects an 18 GW negative

[12] Figure I.C. is a breakdown of signed generator interconnection agreements that have not yet reached their commercial operation date. This is displayed in nameplate capacity, accredited capacity, and projected implementation of approved capacity using Direct Loss of Load (DLOL)-based methodology, which will be implemented in 2028/2029.[12]

[13] Installed capacity, or ICAP, is the hypothetical amount of energy that can be produced under optimal conditions.

[14] Accredited capacity is the actual amount of energy that can be expected under real-life conditions.

[15] More information on MISO Futures Scenarios can be found here https://www.misoenergy.org/planning/futures-development/

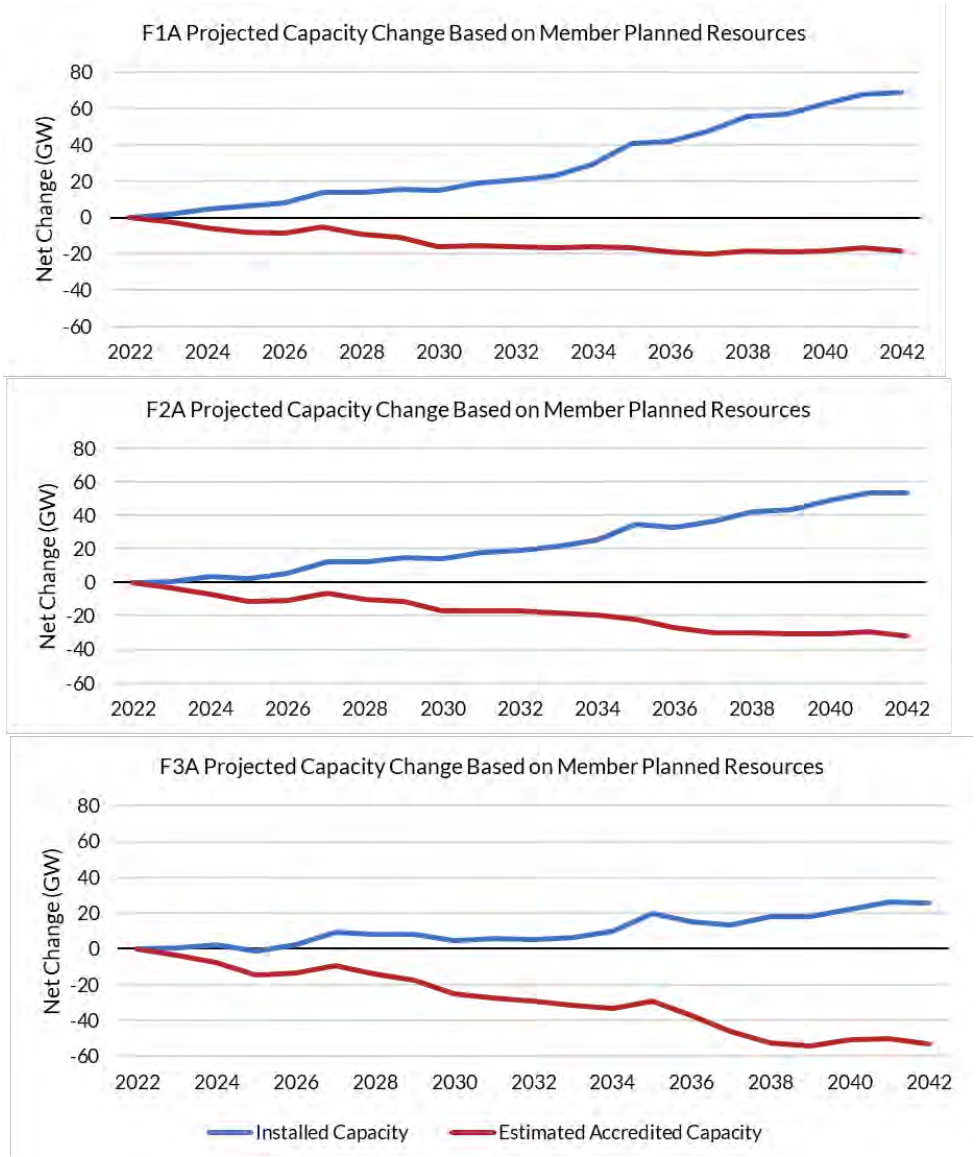
change in estimated accredited capacity across the study period, F2A projects a 32 GW negative net change, and F3A projects a 53 GW negative net change.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

Futures modeling is the key to addressing this shortfall. The MISO Futures team added 29 GW of Flexible Attribute Unit ("Flex") capacity to the Future 2A expansion and siting. Flex units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: Reciprocating Internal Combustion Engines ("RICE") units, long-duration battery[16], traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear Small Modular Reactors ("SMRs"), green hydrogen, enhanced geothermal systems, and other emerging technologies. Flex units do not take away the need for previously identified resources but rather supplement them in periods of energy inadequacy.

[16] Greater than four hours.

Figure I.D.[17]



***Question 6*: In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?**

The 1-in-10 LOLE has served the region well and set the benchmark used to design an adequate system. However, many industry experts, including NERC, have raised questions about this framework's effectiveness in addressing future system risks. Of particular concern is the ability of the future resource fleet to serve load over extended

[17] Figure I.D. comes from Series 1A MISO Futures Report published November 1, 2023. MISO is currently in the process of working with stakeholders to develop an updated Futures Report to reflect current circumstances. More information on Futures Redesign Workshop can be found here www.misoenergy.org/engage/committees/futures/

periods of time, with conditions that may lead to an energy-constrained system. For instance, a future system with no legacy thermal capacity and an abundance of variable and energy-limited generation may experience events much larger in magnitude and longer in duration than today's system. In response to Question 5, MISO's modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. In 2024, MISO reviewed industry recommendations and new trends in the use of resource adequacy metrics. MISO also reviewed and analyzed adequacy metrics calculated in previous MISO studies. The result of this recommends a collaborative approach with states and the industry to revisit the 1-in-10 LOLE criterion, explore alternatives, and provide visibility to complementary metrics.[18] The Resource Adequacy Metrics and Critical Roadmap explores this issue and identifies the next steps by collaborating with the jurisdictions responsible for ensuring resource adequacy in the MISO region, including through the recently formed OMS Resource Adequacy Committee. MISO intends to continue engaging with stakeholders, provide a gap analysis to identify conditions under which energy adequacy materially erodes in a MISO system planned to 1-in-10 LOLE, and collaborate with OMS to develop a framework for identifying thresholds in risk metrics that may warrant potential changes to criteria in MISO's resource adequacy construct. Additionally, MISO plans to publish additional metrics more consistently across resource adequacy studies. MISO also seeks to increase industry collaboration, notably collaborating with other ISOs and research organizations and participating in the NERC drafting team of the new Planning Energy Assurance standard.[19]

<u>Question 7</u>: How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

- ***a. the current 1-in-10 LOLE criterion and the identification of additional analysis needed to evaluate whether there are gaps that need to be addressed. The Resource Adequacy Metrics Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions across the country in using the best modeling methodologies or data sources, etc.?***
- ***b. What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?***

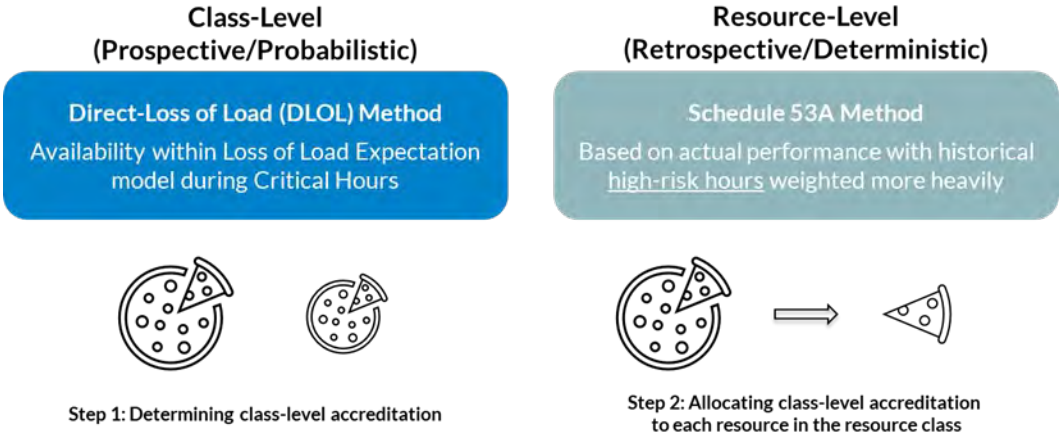
MISO has made significant reforms to improve the resource accreditation methodology to meet the regional reliability needs in the region. These reforms provide a strong foundation to ensure that LSEs bring the resources needed for MISO's operators to

[18] Recommended through the Resource Adequacy Metrics and Criteria Roadmap document.
[19] More information on the NERC Planning Energy Assurance standard can be found here https://www.nerc.com/pa/Stand/Pages/Project-2024-02-Planning-Energy-Assurance.aspx

dispatch resources to meet customer demand for every hour in the day and the resource adequacy market provides a transparent signal for needed resource investment.

MISO is currently transitioning to a two-step accreditation approach (the "Direct Loss-of-Load" or "DLOL"-based methodology) that accredits capacity based on marginal contribution to reliability during periods of highest system risk ("marginal effective load carrying capability" or "marginal ELCC") and on Resource Class. MISO's DLOL-based methodology combines both probabilistic and deterministic elements into a single resource accreditation process. Simply described, the DLOL-based methodology takes two steps by first determining the size of the pie, and second, divvying up the pie.

Figure I.E.



Regional diversity evolved for various reasons and a prescriptive process is not optimal or productive. For example, the Tariff interregional study process with SPP, which has been in place 2020, has yielded no new projects. MISO supports allowing for regional variation to allow RTOs/ISOs to address the unique needs of their regions. MISO has a very diverse footprint: 6 out of 16 regulatory jurisdictions are elected, 4 jurisdictions have moderate to aggressive renewable portfolio standards, 7 jurisdictions lean towards a traditional, fossil fuel approach, and 5 jurisdictions take a balanced approach. The one uniform metric across all states and all RTOs/ISOs is 100% for grid reliability. But MISO does actively engage with all other RTOs in North America, in part through the ISO/RTO Council ("IRC") Markets Committee and also in part with direct discussions with RTO staff to follow best practices in the industry. If design attributes in another RTO look to potentially address MISO issues, we vet these before the stakeholder community and adopt them as appropriate. An example of this is the RBDC design being similar in nature to some of the eastern RTOs construct.

MISO does not speak on behalf of NERC, but MISO agrees with the Commission's previous statements that "using the same model for determining the amount of capacity required and the amount of capacity a resource is capable of providing is a reasonable modeling methodology. This method allows risk to be evaluated on a more granular level

and provides for consistency between the system's resource adequacy requirements and resource accreditation to meet those requirements."[20]

MISO strongly believes that, while respecting regional variations, capacity should be accredited based on performance during times of high risk to properly recognize that not all capacity is created equal, nor will all capacity perform equal in any given situation. Weighing hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours with negative margins and low margin hours with zero or small positive margins by providing higher weight to the former. This ensures that the expected reliability risk during critical hours is being appropriately accounted for in the resource class-level accreditation calculation.

MISO has considered a number of approaches and has found that approaches that accredit an entire class of resources based on the average contribution of the entire fleet do not align with the assumption that capacity exchange in the capacity market is fungible. Instead, marginal accreditation that measures the contribution of the next incremental addition to the resource fleet is a statistically robust method for measuring the incremental, or marginal, contribution to system reliability for any resource that reflects its availability during the hours of highest reliability risk.

The contribution of various resources in meeting resource adequacy requirements must be weighed in relation to their impacts on the system during high-risk hours. MISO has considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio, and alternative weighting based on margin. None of these alternative schemes provide consistent emphasis on the hours with highest unserved energy to the level that weighing hours based on margin does. This properly accounts for the magnitude of expected reliability risks in each hour. This construct provides numerically stable results regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

<u>Question 8</u>: How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?

Appropriately forecasting load growth from data centers and other large loads is a significant challenge across the industry. The issue is present in both RTO and non-RTO regions. The visibility and transparency of the RTO framework allows the challenge to be more clearly identified and visible in the RTO regions. MISO ensures that there is ample supply to meet demand through a prompt capacity market, resource forecasts provided by the OMS-MISO survey, conducted annually, and the RRA effort. MISO works closely with the OMS coordinating and collaborating with all potential PRA reforms to better support grid reliability.

20 See PJM Interconnection, L.L.C., 186 FERC ¶ 61,080 (2024)("PJM Order").

Longer term load forecasts[21] originate with the LSEs. MISO validates and utilizes these forecasts to adequately take into account load growth from data centers and other large loads. MISO subject matter experts validate forecasts for the upcoming planning year through a random sampling approach. Included in this sampling is an assessment of the accuracy of the past year's forecasts which outlines a set of detailed questions related to the forecasts that each LSE must answer. Accounting for load growth from data centers and other large loads is asked directly to LSEs with a requirement on the LSE show support for their assumptions.

MISO recently updated our long-term[22] load forecasting process to better account for the impact of new sources of load growth on long-term planning. The process uses bottoms-up estimates of load for each of a set of drivers (e.g. data center announcements) along with assessed probabilities (e.g. likelihood of an announced data center being built on time) to develop a range of credible forecasts. These forecast are benchmarked against the LSE-provided forecast in the first few years. Longer-term load forecasts support MISO's transmission planning efforts and inform member resource planning decisions.

Question 9: How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

Demand resources acting as supply are viable alternatives for LSEs to use in meeting their capacity obligations, and are used quite abundantly in MISO. MISO continues to explore future implementation of DERs to assist in resource adequacy challenges and is working closely with the OMS to be transparent around any future reliability issues. MISO has also recently filed reforms intended to better accredit demand-side resources to ensure those are resources appropriately valued as a resource adequacy tool.

Question 10: How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

The changing resource mix requires more transmission to get generation to load. MISO's Tranche 2 portfolio of LRTP projects is progressing, with approval from MISO's Board of Directors in 2024. Planning is complex, but MISO has balanced the need to move quickly to meet resource adequacy objectives with the need to develop a robust, lowest-cost portfolio. Through the roll out of LRTP projects, transmission projects are in progress in areas with the greatest need based on ranges of economic, policy, and regulatory inputs. Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA. These import/export limits are reevaluated annually and modeled in the PRA, allowing resources to meet local and regional capacity requirements.

[21] Anything longer than a week or two out or any load forecasts that are not used in the Energy and Operating Reserve markets.
[22] 20-year.

To get customers to build out generation, they mainly need reasonable costs and cost certainty. MISO's JTIQ ("Joint Transmission Interconnection Queue") addresses this by spreading costs among interconnection customers so that customers do not hesitate to build out due to fear of being the project that triggers a higher cost than what is feasible. This allows all parties to pay reasonable costs that they can anticipate in advance.

Panel 5: MISO's Resource Adequacy Challenge

***Question 1*: What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?**

- ***a. Is MISO's resource adequacy construct delivering resource adequacy in MISO?***
- **b.** ***What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?***

There are urgent and complex challenges facing electric system reliability in the MISO region. These challenges include generation fleet change, regulatory hurdles, extreme weather events, and load additions, to name a few. In light of this, utilities, states and MISO have taken steps to coordinate with urgency to avoid any mismatch between the pace of adding new resources and the retirement of older resources. MISO is confident that by addressing the four pillars of the Reliability Imperative the region will remain in excess of the 1-in-10 LOLE Standard.

MISO uses a few tools to assess the state of resource adequacy in its footprint. The RRA is one of the periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In contrast, the OMS-MISO Survey is focused on the near term and is based on much lower expectations of new installed capacity, reflecting the pace at which resources have received interconnection agreements and come online in recent history. Each study was designed for a different purpose, uses different data inputs, covers different time periods, and uses different methodologies and modeling assumptions. Accordingly, the results differ. For example, the RRA assumes members and states will be able to add new generation capacity at an unprecedented rate of 17 GW/year for the next 20 years to reliably achieve their publicly announced resource plans and policy goals. Accordingly, the RRA projects capacity surpluses in 2030 and beyond. The 2024 OMS-MISO Survey therefore forecasted a range of possible outcomes, varying from capacity deficits beginning in 2025 to capacity surpluses through 2029. These divergent results reflect that the RRA and the OMS-MISO Survey were designed for different purposes and use different data inputs, methodologies, assumptions and time horizons.

In sum, given that the MISO states have rights towards resource adequacy, take their roles and responsibilities seriously, and MISO is providing transparency in expectations of future resource adequacy plans, we are confident that the footprint will continue to be resource adequate in the near and longer term. Capacity margins are declining but remain in excess of the 1-in-10 LOLE standard. MISO successfully implemented the RBDC in the capacity market for the 2025-2026 PRA. This construct provides more accurate price

signals and encourages resource investments by reflecting the contributions to reliability incremental megawatts can add to the system. The capacity market has changed from an annual to a seasonal construct to better reflect the risks to resource adequacy shifting from mainly the summer peak demand conditions to periods across all seasons and time periods. On the supply side, resources are being accredited based on availability during all times of need, across all seasons. In the most recent PRA, the megawatts that cleared in the summer season exceeded 1-in-10 LOLE by an additional 2 percentage points because the reliability contribution of these additional megawatts exceeded the cost to procure them.

The RBDC construct values the reliability contribution of incremental MWs, the price signals that reflect that reliability value, and the prompt and residual nature of the capacity market. Prompt auctions have less uncertainty around demand values and supply availability. The residual nature recognizes that, in MISO, most LSEs come with resources that meet their requirements. There is the possibility that, without other actions, the prompt nature leaves little time to address any issues that arise, like shortfalls. This potential drawback is addressed through the OMS-MISO survey and RRA effort, providing more transparent information around future reliability requirements and resource margins.

Question 2: How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?

The capacity shortfalls that occurred in the 2022/2023 planning year promoted a greater sense of urgency to MISO's ongoing efforts to continually enhance its market design. The vertical demand curve served the region well for many years but as the resource mix has changed and extreme weather events have increased, customer confidence in the capacity market eroded. The vertical demand curve created extreme price volatility that disincentivized investments. The RBDC, implemented for the first time in the 2025/26 PRA, has addressed this by providing more accurate price signals and encouraging resource investments by reflecting the contributions to reliability that incremental megawatts can add to the system. Most LSEs within MISO either have owned or contracted for resources that meet their obligations but, regardless, the more efficient capacity prices being established through the RBDC construct provide much better information to LSEs, RERRAs and generation owners to make more informed going forward investment decisions. This is akin to how Real Time energy market prices work – a very small percent of transactions are subject to real time prices, but Day Ahead prices are informed by what happens in real time. Changes to the resource adequacy construct highlighted above and the information provided through the OMS-MISO survey and RRA effort have initiated renewed efforts on the part of LSEs and RERRAs to address resource adequacy requirements.

States and stakeholders have shown confidence in the MISO capacity market to achieve resource adequacy at just and reasonable rates. This is in large part due to the collaborative relationship between MISO and its stakeholders. Since MISO's start, deference has been made to the states and other RERRAs with respect to resource

adequacy rights. MISO has worked closely with OMS, the Independent Market Monitor ("IMM"), and other stakeholders to change the capacity market to a seasonal construct and implement the RBDC. OMS has reinforced the need for MISO's seasonal capacity construct and RBDC to properly accredit capacity in a world with more extreme weather and faster load growth than ever.

***Question 3**: How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?*

The seasonal construct has highlighted the seasonal differences in the planning reserve margins required to meet the reliability standards, the varying Loss of Load Probability distributed across the seasons, the variability in the values of accreditation for resources by season (the Seasonal Accredited Capacity, or, "SAC") and significant differences in load variability season by season. This has helped MISO more accurately determine its resource adequacy needs as extreme weather has reconfigured what it means to be resource adequate. Being resource adequate on the hottest day in the summer does not necessarily mean that an LSE is resource adequate on the coldest day in the winter. SAC allows MISO to stay reliable throughout the entire year by targeting the unique needs of each season.

Accreditation changes, SAC in particular, are much more reflective of availability of resources to meet needs in each season.[23] The changes MISO has made to accreditation has a prospective and retrospective tint to it on purpose, as it captures the class level performance during projected risk conditions, while still being grounded and calibrated against the reality of how actual units performed over the last 3 years. This allows good performers to continue having a great incentive to continue that performance. Spring & fall seasons can be quite variable with summer and winter weather patterns bleeding into the shoulder seasons. For example, as the weather changes, winter weather may continue into early spring. Each successive planning year provides MISO with additional data to support market design. Currently there is a limited sample size for assessing accreditation. MISO is addressing these and other issues with renewed effort on appropriate LOLE modeling, shared with stakeholders.

***Question 4**: How does MISO establish its load and resource forecasts?*

- ***a. How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements?***
- ***b. Does MISO verify the forecast methodologies and accuracy of forecasts?***
- **c. *Have the assumptions driving load and resource forecasts changed over time? If so, how?***

[23] The answer to question 7 in the above panel more fully describes the changes we have made.

d. ***How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?***

e. ***How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?***

Anything longer than a few weeks or any load forecasts that are not used in the Energy and Operating Reserve markets are considered "longer-term forecasts" and originate with the LSEs. With such a wide and diverse footprint in MISO, LSEs are best positioned to have information on where energy & demand is moving in its localized area. Resource forecasts are provided by the OMS-MISO survey and the RRA efforts and are conducted annually.

MISO integrates previous LSE forecasts as direct inputs into the LOLE modeling which determines the planning reserve margin requirements. MISO verifies the forecast methodologies and accuracy of forecasts provided by LSEs. LSEs submit documentation, including a narrative with a complete description of the type of models being used, statistical model results, and spreadsheets with historic and forecast data, to MISO to support the LSEs' forecast demands. MISO then draws a random sample of these LSEs broken up into identified segments. Current segments are large LSEs (demand greater than 1000 MWs), medium LSEs (demand between 100 MWs and 1000 MWs), and small LSEs (demand less than 100 MWs). MISO subject matter experts then assess and validate the credibility of the LSE's submittals. Included in this is an assessment of the accuracy of the past year's forecasts.

The values for the variables used in the forecast have changed over time and been updated to weigh different inputs appropriately. The variables themselves have not necessarily changed. For example, LSEs consistently see new commercial and industrial facilities being built and older facilities being closed, but more recently, new load growth predominantly from data centers has driven expectations of higher load growth in the near term. Statistical models calculate the weights endogenously.

Certainly, some assumptions are more uncertain than others. On the resource side, getting through the queue process has significant uncertainty. On the demand side, for instance, significant load additions, like data centers, have to be studied for reliability impacts and come with uncertain timing of these additions.

The forecasts have performed to acceptable industry standards in the past, though load growth has been minimal over recent time periods. MISO, however, is strengthening its load forecast validation process, providing more guidance on acceptable practices, and looking for discrete changes to the load forecasts.

Given the prompt nature of the PRA, demonstration of commercial readiness of prospective new load additions has always been a consideration.

***Question 5*: To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?**

The barriers affecting resource adequacy in the MISO footprint are less to entry, but rather barriers to success once projects exit the interconnection queue. Factors such as funding, off-taker agreements, supply chain, and permitting and citing delay projects from being built once they exit the generator interconnection process. There is over 50 GW of projects that have a signed generator interconnection agreement and are not yet online. Over half of them are already signaling they are delayed and cannot meet their originally expected in service date. New long-term stability and certainty in federal energy policy has further worsened these expected delays. A clearer signal on federal energy policies and import tariffs impacting necessary electrical components would promote investments and ease these delays. To improve visibility into these generators with interconnection agreements signed but not yet online, MISO created a Commercial Operation Date Dashboard on our website to help stakeholders understand when these resources are expected to come online.[24]

Another concern is the queue backlogs themselves. Although there is a significant amount of generation with a GIA waiting to come online, these resources may not have all the attributes necessary to ensure long term resource adequacy. The MISO queue has historically represented wind, solar, and battery storage projects. This includes 86% of the resources with a GIA waiting to come online, and over 96% of the 300 GW of projects in ongoing queue cycles. A significant shift is occurring for MISO's next queue cycle that will close in September of 2025. Currently there are 44 GW of projects submitted in the 2025 queue, and 26% of that is new natural gas resources. The queue backlog and delays mean these new resources may have to wait years to get an interconnection agreement.

To aid in the development of resources needed to address resource adequacy, MISO introduced a new process to study select projects outside the interconnection queue. The ERAS process was filed at Commission in March. This process would allow MISO to study individual projects, acknowledged by their RERRA and an off-taker agreement, with load to be studied by MISO through ERAS. This process would allow these projects to receive a GIA within months instead of years. This temporary process will only be in place until the queue backlog and delays have been mitigated.

***Question 6*: To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?**

[24] See the C.O.D. dashboard here https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

Availability of regional transmission capability affects the ability to import/export resources across the MISO footprint. MISO captures these capabilities in the capacity import and export limits modeled and respected in the PRA.

MISO can increase study effectiveness to better address transmission capabilities. MISO is implementing the generator interconnection request cap ("queue cap") and interconnection process improvements to achieve this. The queue cap limits requests at 50% of each region's non-coincident peak load. This follows a first-in, first-selected approach to allow for more manageable request numbers which will improve effectiveness and efficiency. MISO is also implementing SUGAR software which has shown significant time reduction for preliminary studies so far. Additionally, a new application portal will be available for customers in June with improved interface and data quality.

Question 7: Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why?

No, the enhanced reforms with the DLOL construct provide an effective tool to deliver resource adequacy. The DLOL-based methodology respects states' rights and responsibilities over resource adequacy. RERRAs have well established processes in place to meet the resource adequacy requirements determined by MISO and are expected to continue to do so. The residual nature of the resource adequacy construct is working as intended. The RRA studies and the OMS-MISO survey further support resource adequacy decision and planning across the footprint.

Additionally, MISO is not aware of any alternatives to the current residual market that would perform better in MISO at this time. Recent capacity market enhancements such as SAC, RBDC, and DLOL-based methodology will continue to be implemented, improve market signals, and support needed resource availability. MISO continues, however, to consider design changes to the resource adequacy construct that can enhance reliability and support needed resource investment decisions.

Question 8: What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region's resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?

Every effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid. MISO appreciates states' responsibility for resource adequacy and acknowledges that LSEs have the obligation to serve their end-use customers. Both LSEs and RERRAs take their responsibilities seriously. Continued coordination is critical. With the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable. Given this, MISO can assess, analyze and provide transparency on where resource adequacy conditions are moving, providing additional macro level views on the issues to help inform states and LSEs. MISO translates the 1-in-10 LOLE

into planning reserve requirements and the responsibility of MISO to facilitate residual capacity transactions through the PRA.

MISO works closely with the OMS and RERRAs to communicate regional needs to maintain resource adequacy. Both the OMS-MISO Survey and the RRA provide information to MISO on state-specific forecasts. From this state-specific information, MISO conducts analyses that are made public around the need for different types of resources to meet the reliability standards being imposed by NERC.

MISO has not directly studied the effects of state public policy. MISO has, however, in its RRA studies, provided detailed analyses around the implications of state public policy. One example of this is increasing renewable energy trends. MISO puts priority on maintaining independence from individual MPs. We are fuel source and policy neutral, meaning we do not favor, prefer, or advocate any particular fuel or policy outcome. That doesn't mean, however, that we are disinterested observers. Our mission is to ensure the continued reliability of the bulk electric system.

III. CONCLUSION

MISO appreciates the opportunity to provide these responses to the Commission's questions regarding Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions.

Respectfully submitted,

/s/ Todd Ramey

Todd Ramey

Senior Vice President of Markets and Digital Strategy
Midcontinent Independent System Operator, Inc.

Appendix I

Appendix I summarizes data provided in this written statement through graphs, charts, and other images.

Figure I.A.

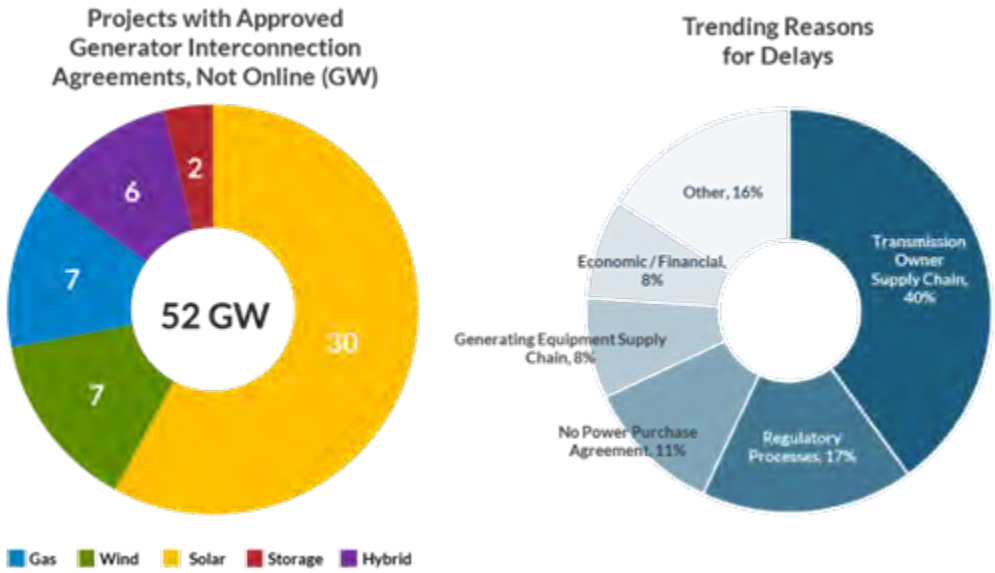


Figure I.A., found on page 13, compares 52 GW of Approved Generator Interconnection Requests in MISO with a breakdown of reasons for reported developmental delays and the percentage of delays affected by such set back.

Figure I.B.

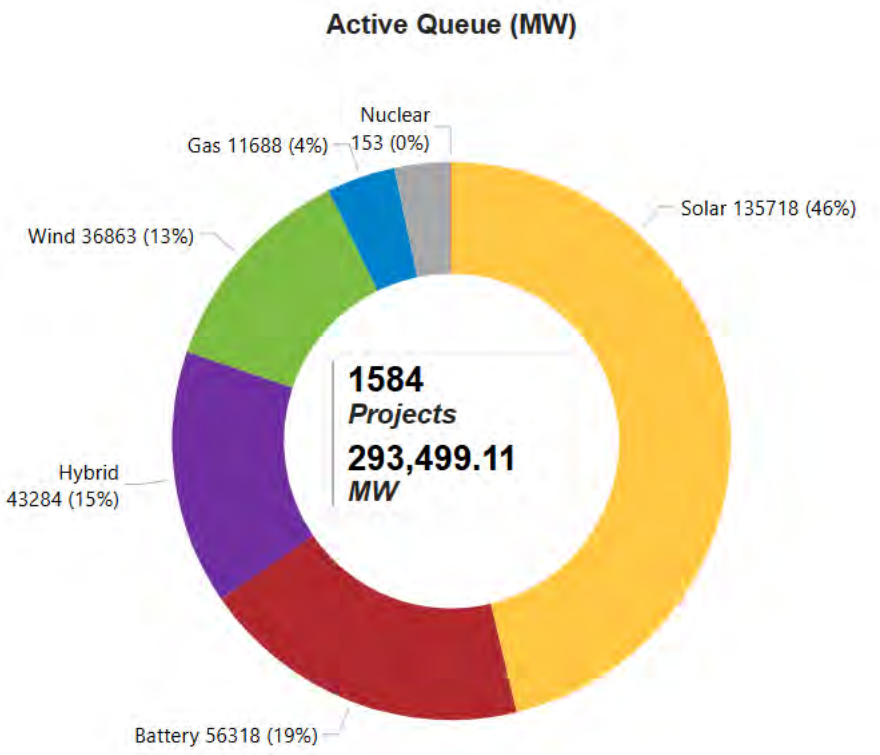


Figure I.B., found on page 14, illustrates the active MISO Generator Interconnection Queue by resource type. Does not reflect additional nameplate capacity from repowering existing generating facilities. As of February 6, 2025.

Figure I.C.

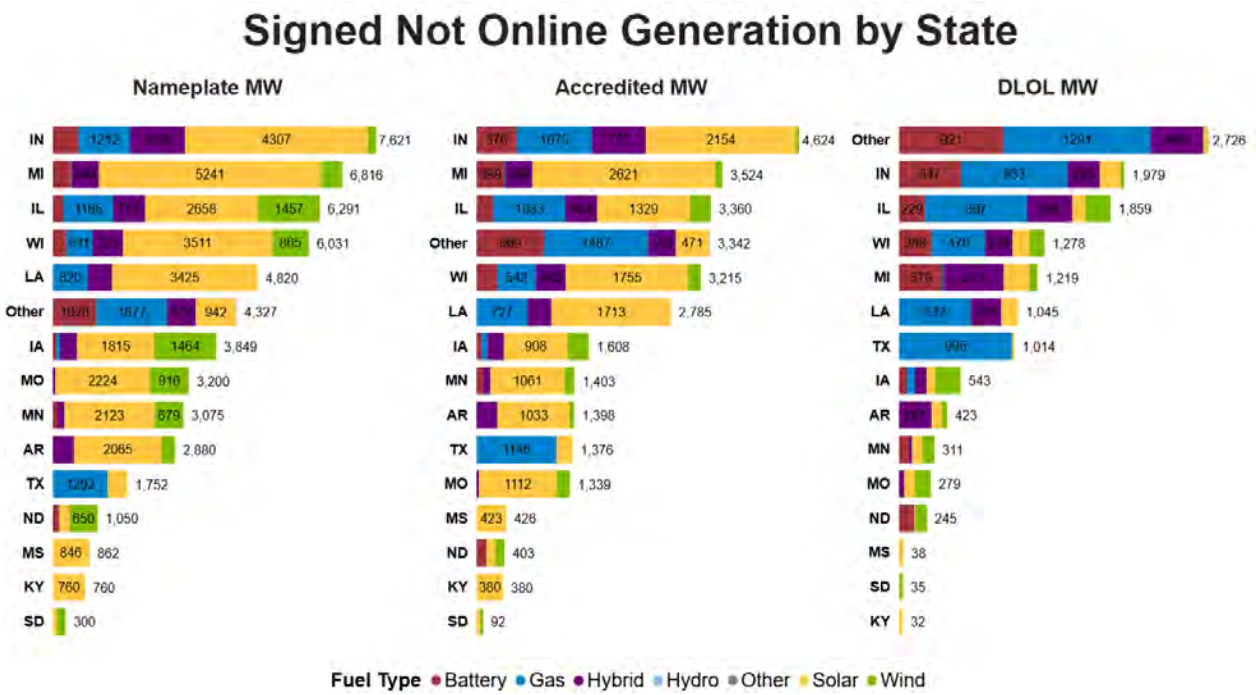


Figure I.C., found on page 15, illustrates a state-by-state comparison of MWs of Approved Generator Interconnection requests in nameplate capacity, accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure I.D.

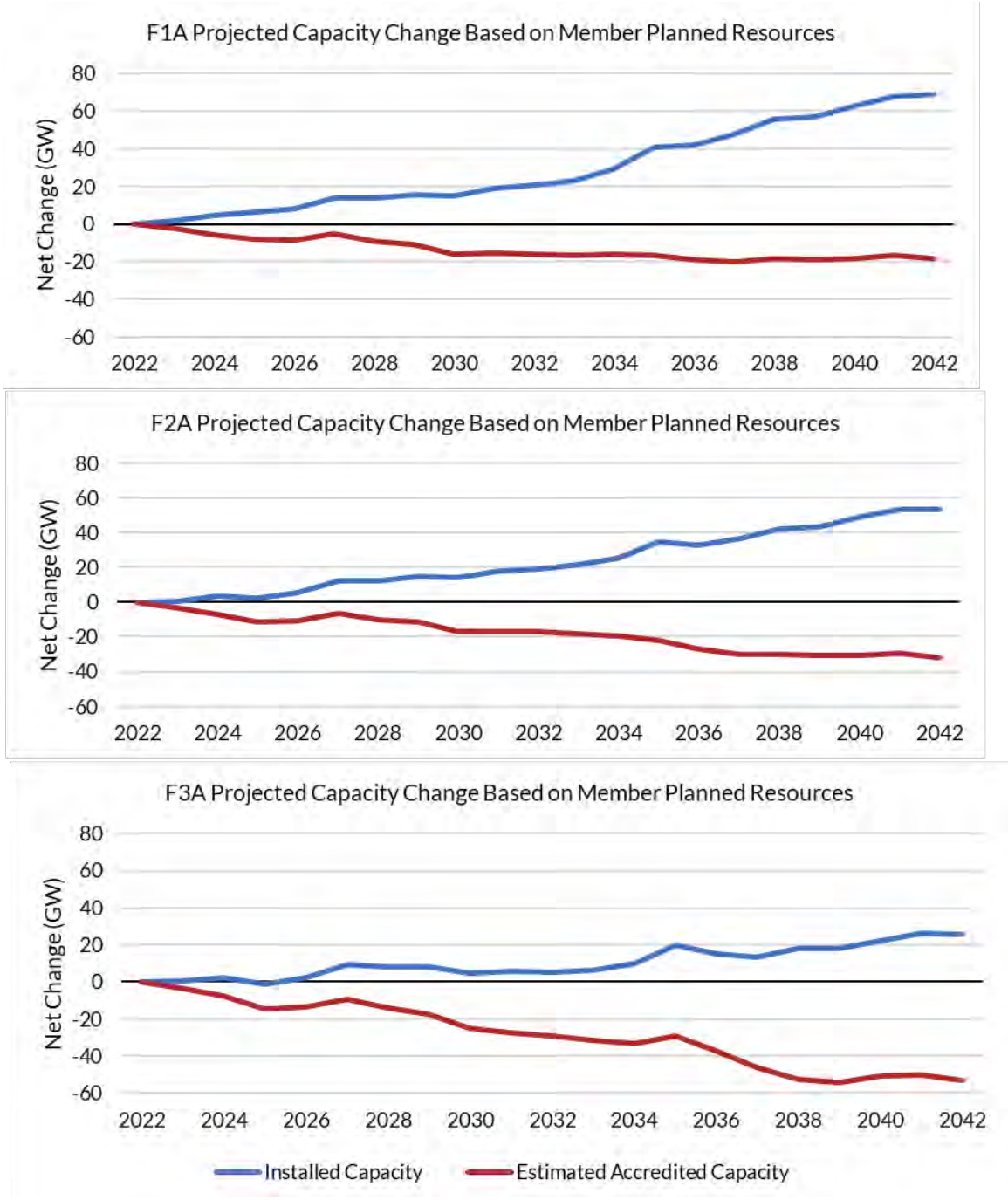


Figure I.D., found on page 17, shows projected capacity change from 2022 to 2042 for all three Futures based on existing and member-planned resources. Differences in the net

change of installed and estimated accredited capacity are driven by the varying age-based retirement assumptions applied to existing resources across Futures. Figure I.D. is sourced from Series 1A MISO Futures Report. More information on this report can be found here https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

Figure I.E.

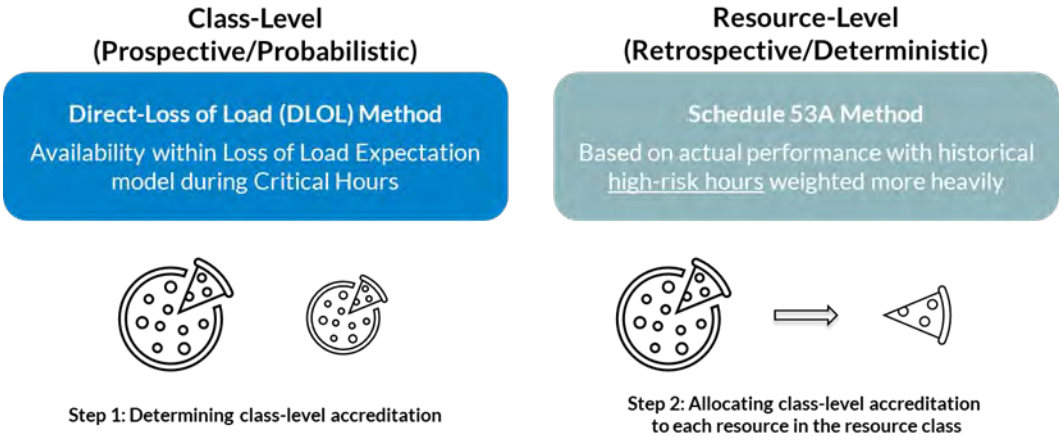


Figure I.E. explains the two-step DLOL-based resource accreditation methodology, further explained on pages 19. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Appendix II

Appendix II supplements information provided in this written statement with additional data on state generation retirements and additions.

Figure II.A.

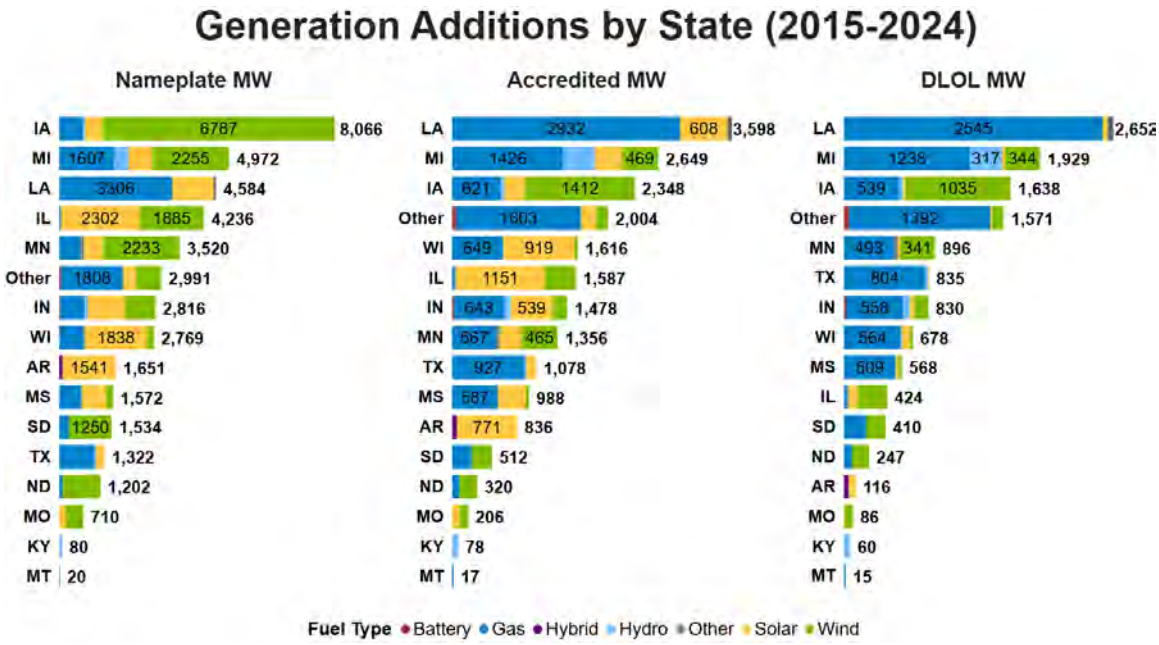


Figure II.A. illustrates a state-by-state comparison of generation that has come online over the last 10 years in the MISO region through new generation, surplus, and replacements. This is measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.B.

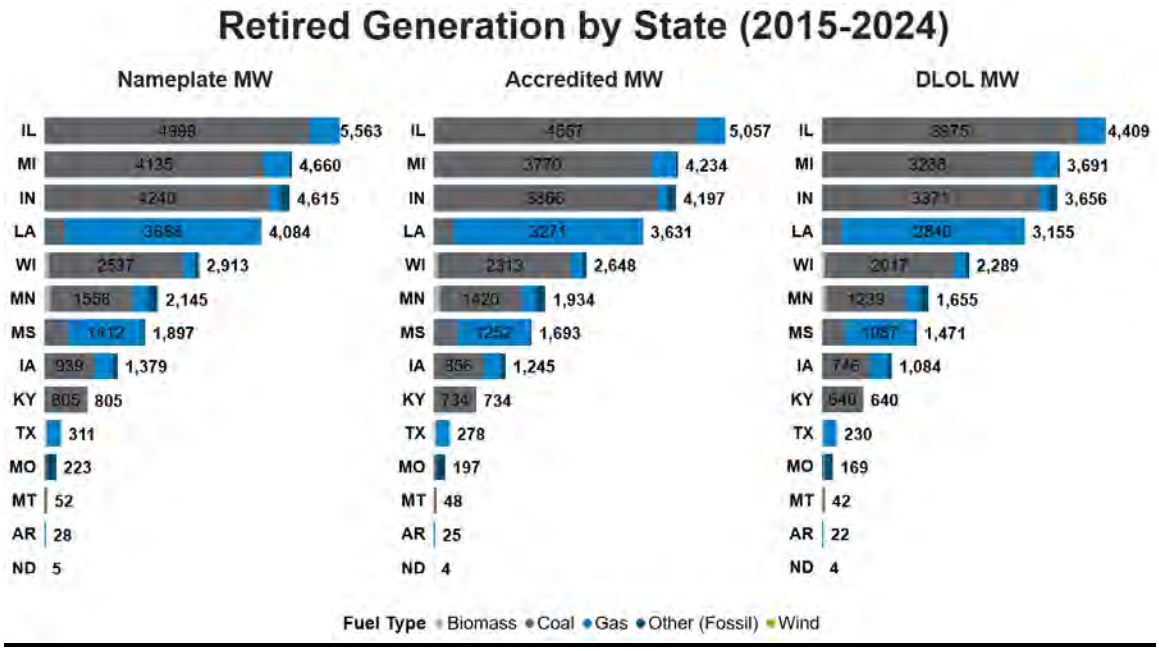


Figure II.B. illustrates a state-by-state comparison of retired generation over the last 10 years in the MISO region, measured by nameplate capacity, current accredited capacity, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Figure II.C.

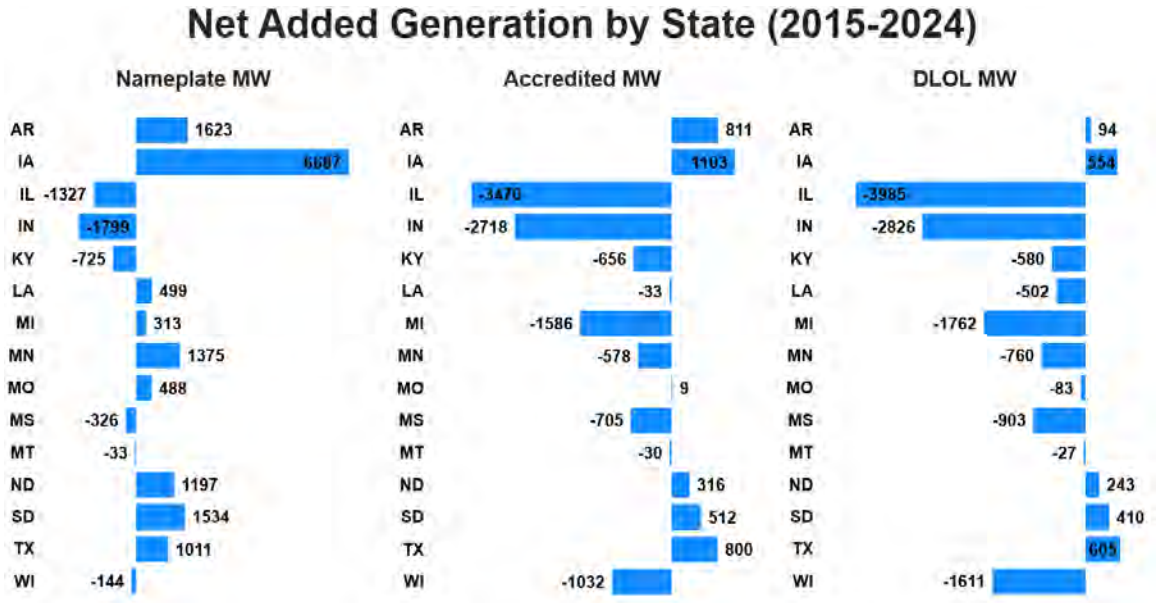


Figure II.C. illustrates a state-by-state comparison of net generation changes in megawatts over the last 10 years in the MISO region, measured by nameplate capacity, current accreditation, and DLOL-based methodology. The DLOL-based capacity accreditation assumptions are based on the fuel-based class average assumptions that are expected to be in place for the 2028/2029 planning year. The 2028/2029 Planning Resource Auction will be the first to utilize the DLOL-based methodology.

Document Content(s)

Panel1_Ramey_MISO (4).pdf.....1

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 35

Patton MISO Comments

TECHNICAL CONFERENCE COMMENTS OF
DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

Meeting the Challenge of Resource Adequacy in RTO and ISO Regions
Docket No. AD25-7-000
June 4-5, 2025

Summary Bullets

- The resource adequacy challenges and risks in MISO are not nearly daunting as portrayed by MISO planning reports or the NERC 2024 Long-Term Reliability Assessment.
- For the first time, MISO has assembled all of the design elements needed to allow its capacity market to facilitate long-term decisions that achieve resources adequacy:
  - Prompt, seasonal market framework;
  - Demand aligned with reliability: reliability-based demand curves; and
  - Supply aligned with reliability: marginal reliability-based resource accreditation (to be implemented in 2028).
- The threats or issues achieving resource adequacy are now not related to the market design or rules, they include:
  - *State regulatory alignment with markets*: states must facilitate planning by their regulated entities that achieve both state policy goals and reliability objectives.
  - *Misalignment of MISO planning and markets*: planning and markets must be well-aligned to prevent uneconomic planned investment from undermining the incentives to invest in resources signaled by the markets. We have substantial concerns in this area.
  - *Market instability:* The most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large.
- There are many reasons to be optimistic about long-term resource adequacy in MISO:
  - MISO has made tremendous progress toward an efficient market design that will provide clear, efficient locational capacity price signals.
  - MISO's states and utilities are committed to maintaining the reliability of the system, in addition to meeting state policy goals.
  - I hope to continue to recommend changes to MISO's planning processes to improve their alignment with resource development trends, state goals, and market signals.
  - Hence, I recommend that the Commission not pursue or mandate substantial changes to MISO's capacity market.

WRITTEN STATEMENT OF DAVID B. PATTON, PH.D.
MISO INDEPENDENT MARKET MONITOR

The increase in projected load growth, the transition of the generating portfolio to much higher reliance on intermittent resources, and accelerating retirements of conventional dispatchable resources has increased resource adequacy concerns. I appreciate the opportunity to address questions regarding resource adequacy in the MISO region today.

Current Status of Resource Adequacy and Planning Projections

MISO is more than adequate moving into the Summer of 2025, and we do not have substantial concerns about the MISO region in the near term. The Commission cites the findings in the NERC 2024 Long-Term Reliability Assessment that MISO is at risk of running short of supply as soon as the Summer of 2025. We have reviewed this report and do not believe its results are accurate because it understates MISO's capacity in the areas of demand response, behind-the-meter generation, and firm capacity imports by more than 8 GW. Additionally, they consider potential retirements of coal, oil, and gas-fired resources that have not materialized.

Additionally, it is important to recognize that, unlike some other RTOs, MISO has tremendous import capability that is routinely utilized during tight conditions to supplement its internal resources. During emergency conditions, it has typically imported well over 4 GW of additional supply. Hence, we have no substantial concerns regarding the adequacy of resources in the MISO region in the near term.

The Commission also cites MISO's 2024 Regional Resource Assessment which asserts that 17 GW of new resources will need to be built every year for the next 20 years. For reasons I have documented for MISO and its stakeholders, this is not a credible forecast. MISO planning models assume that virtually all of the new capacity to be built over the next 20 years will be intermittent renewable resources, despite the fact that their reliability value under MISO's future marginal accreditation approach will fall to close to zero.

This is partly why such a massive amount of new capacity are reported to be needed. If one were to assume that participants will rationally build hybrid renewables, storage and dispatchable resources, the 17 GW per year of new resources falls to roughly 2 to 3 GW per year. Some of this demand for resources in the near term is likely to be satisfied by delayed retirements now that MISO's capacity market is beginning to send more efficient price signals to the market participants.

Further, investment in these classes of controllable resources will still allow MISO states to achieve its carbon goals and greatly reduces the transmission needs in the MISO region, which I have also indicated to MISO and its stakeholders.

Achieving Resource Adequacy in the Long-Term in MISO (or any RTO)

Few topics in wholesale electricity markets have engendered the debate and controversy as have resource adequacy. At the outset, it is helpful to review why capacity markets exist. Most RTOs and ISOs minimum planning requirements that correspond to a prescribed level of reliability, the most common of which is the one loss of load event in ten-year standard. The RTOs determine the resources that are needed to meet this standard.

The primary economic issue is that the 1-in-10 reliability standard implies a value of lost load (VOLL) in excess of $200,000 per MWh. Since the RTOs and ISO's do not price shortages in the energy and reserve markets based on a VOLL this high, energy and operating reserve markets will typically not provide enough revenue to keep this maintain capacity margins that will satisfy this reliability standard.

The capacity markets were developed to supplement the RTOs' energy and ancillary services markets to provide the necessary economic signals to inform long-term capacity decisions, including investment, retirement, and maintenance of resources. However, capacity markets are not the only approach for pursuing resource adequacy. In general, there are three primary approaches to achieve adequate resources through competitive wholesale electricity markets:

1. Capacity market – Designed to directly procure a sufficient quantity of capacity to satisfy a specified reliability standard.

- Pros: Predictably generates the net revenues needed to incent suppliers to invest in new resources and maintain existing resources to satisfy the reliability standard.
- Cons: Requires more complicated rules related to accreditation of generation and load resources. Poor rules can undermine the performance of the market, e.g., the vertical demand curve that had previously used in the MISO capacity market.

2. Decentralized capacity requirements – Some markets require LSEs to self-supply or procure capacity to satisfy a specified capacity requirement. This is effectively a decentralized capacity market that operates bilaterally.

- Pros: Increases the likelihood of satisfying the specified reliability standard compared to an energy-only market.

  Cons: Prices and procurements are likely to be much less efficient compared to a centralized capacity market. It is also difficult to model transmission constraints and system requirements as accurately as in a centralized capacity market.

3. Energy-only market – this market relies primarily on expected shortage revenues in the energy and ancillary services markets to motivate investment.

- Pros: Provides strong performance and availability incentives and it is closely aligned with reliability.
- Cons: Capacity levels are likely to be less than needed to satisfy the reliability standard. Even if a very aggressive VOLL is selected to price shortages, higher capacity margins produce less frequent shortages making it difficult to generate sufficient revenue. This market alternative can also produce highly volatile year-to-year costs and revenues that can be hedged by contracts.

If an RTO adopts a reliability standard that must be satisfied, a well-designed capacity market will generally be the most efficient means of doing so. However, MISO has struggled historically to develop an efficient capacity market design on both the supply and demand side. In recent years, most of the design issues have been addressed. MISO has now developed and has or will implement:

- A seasonal capacity market framework that operates in a prompt timeframe, roughly two months before the planning year commences.
- Reliability-based demand curves in 2025 that, for the first time, aligns the market demand with the reliability that the capacity provides.
- Marginal reliability-based capacity resource accreditation, which will be implemented in 2028. This ensures that the relative reliability value of different types of capacity resources is accurately reflected in the market.

Together, these fundamental elements will provide for efficient capacity procurement and prices that will efficiently facilitate investment and retirement decisions to maintain resource adequacy. Many of these decisions are made through utility and state planning processes, and others will be made by unregulated market participants. An efficient capacity market will facilitate both types of decisions.

To illustrate the importance of these design improvements, we can look at the results of MISO's recent 2025/2026 Planning Resource Auction (PRA). This was the first year under MISO's new reliability-based demand curves in its seasonal capacity market. The market cleared at $667 per MW-day in the summer and averaged more than $210 per MW-day for the entire planning year. This reflects almost 90 percent of the Cost of New Entry (CONE) of a gas peaking resources net of the energy and ancillary service net revenues the markets provide. This price level is efficient and reflects the marginal reliability value of resources in MISO because it procured only 2 percent more capacity than the minimum requirement. Importantly, these prices send clear signals to both developers and owners of existing generators regarding the value of resources in the MISO region.

In contrast, under the vertical demand curve that MISO had previously utilized, prices would have cleared at roughly $20 per MW-day. These prices would provide little incentive to build new units or maintain older existing units. We have shown in prior reports that the vertical demand curve contributed to large quantities of retirements of merchant resources and contributed to the tight capacity conditions that currently exist in the Midwest region.

Given MISO's tremendous progress in the design and implementation of its capacity market, we see no benefit in considering fundamental reforms to MISO's capacity market or alternative resource adequacy approaches.

Threats or Challenges to Resource Adequacy in MISO

Although it is essential for MISO's capacity market to be well-designed and competitive so it will produce efficient economic signals to support resource adequacy, there are other issues outside of the market that must be addressed or coordinated.

First, because most of the load is served by regulated utilities in MISO, state policy and regulation will play a key role in achieving resource adequacy. Although many of the states in MISO have aggressive carbon reduction goals, I believe they are also committed to reliability. Mandating and overseeing planning processes by regulated utilities that are designed to achieve both environmental and reliability objectives will be critical. In my discussions with states and with the regulated utilities, I believe they are committed to both objectives. The reforms MISO has implemented, particularly the transition to marginal accreditation, will inform these processes and facilitate success in achieving both objectives.

Second, MISO's planning processes must be well-aligned with its markets. While MISO does not determine the future development of resources in the region, it projects such development and load growth that together determine the MISO's transmission needs. Ultimately, therefore, these planning process help determine the future transmission investment in the region. Transmission investment that occurs outside of the market must be well-coordinated with investment in resources that are in-part or fully facilitated by the market. Excessive uneconomic investment in transmission that is guaranteed by regulated customers will undermine the incentives to invest in resources that can address the same transmission bottlenecks.

For example, strategically located storage resources in generation pockets can charge at low or negative prices when intermittent resources produce at very high levels would otherwise need to be curtailed to avoid overloading a transmission constraint. MISO's transmission congestion can create profitable opportunities for resources to site in these types of areas at no cost to regulated customers in order to relieve the congestion. Hence, it is critical to avoid excessive investment in uneconomic transmission, which I believe requires independent oversight given the concerns the IMM has identified in recent planning cycles.

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Ideally, such oversight would be provided by the Commission but, unfortunately, FERC does not review or approve the portfolios of new transmission emerging from MISO's transmission planning process before these costs are embedded in transmission rates. This raises the potential for uneconomic transmission investment to raise RTOs' transmission rates to unreasonable levels. We believe the Commission should consider solutions to address this regulatory gap.

Finally, the most well-designed markets will fail to motivate efficient investment over the long term if the regulatory risk associated with changing market rules is large. This is because developers will discount future expected market revenues if they believe there is a reasonable probability that the RTO or the Commission will make substantial changes to the market rules or eliminate the market. Given the progress MISO has made to improve the design and performance of the capacity market, I recommend that the Commission not pursue or mandate substantial changes to it.

This concludes my written statement.

Document Content(s)

Panel5_Patton_IMM.pdf.....1

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 36

MISO Elliott Max. Gen. Event Overview

Overview of Winter Storm Elliott December 23, Maximum Generation Event

Reliability Subcommittee

January 17, 2023

All data included in this presentation is preliminary as of January 12, 2023, and is subject to change

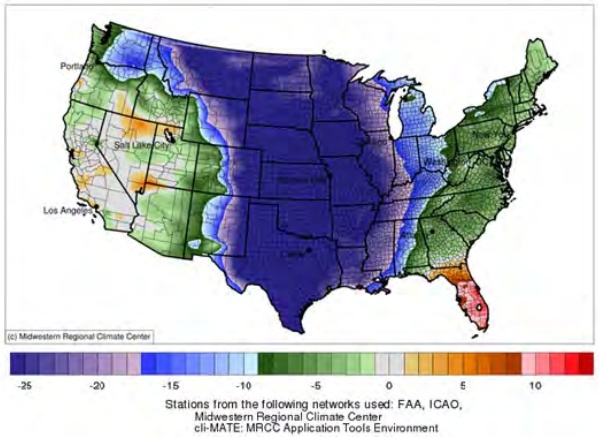
Executive Summary

- Winter Storm Elliott delivered rapid, extreme cold to the Eastern Interconnect in December as well as gas supply challenges and historic load forecast volatility
- MISO had enough capacity to manage uncertainty while serving exports to our neighbors
- There were no customer interruptions
- Lessons learned from Winter Storm Uri contributed to successful operations during Elliott; subsequent analysis will lead to additional lessons learned
- Load forecast uncertainty and fuel supply availability are examples of the increasing uncertainty being addressed under MISO's Reliability Imperative

On December 23, Winter Storm Elliott brought significantly below normal temperatures to MISO, driving high demand for heating; drawing similarities to Winter Storm Uri in 2021

WINTER STORM URI
FEBRUARY 12-18, 2021

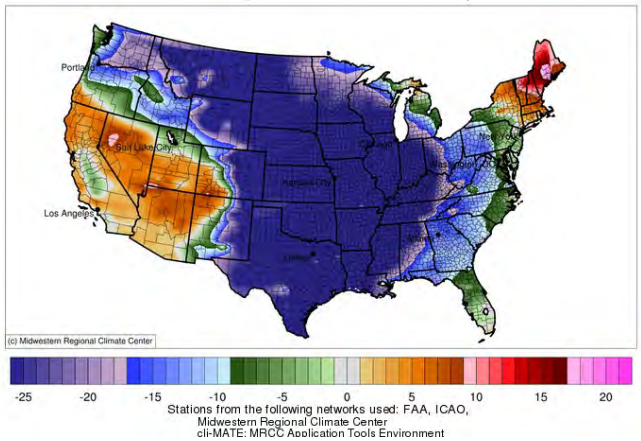
Average Temperature:
Departure from 30-Year Normal



System Peak Load	103 GW
Unplanned Outages *(South)*	18 GW
Scheduled Load Modifying Resources*	531 MW
RDT Max Flow & Direction	3.2 GW N-S
Precipitation: *Abundant snowfall across MISO's South and Central regions*	

WINTER STORM ELLIOTT
DECEMBER 23, 2022

Average Temperature:
Departure from 30-Year Normal



System Peak Load	107 GW
Unplanned Outages *(additional from previous day system-wide)*	19 GW
Scheduled Load Modifying Resources*	1.2 GW
RDT Max Flow & Direction	2.7 GW N-S
Precipitation: *Modest snowfall across MISO's North and Central regions*	

*Load Modifying Resources requested for the peak load hour for the noted storm time period

Emergency operations were required to access additional capacity to mitigate uncertainty and support our neighbors

ALERTS

Cold Weather Alert (South)
DEC 22, noon EST – DEC 26, noon EST

Unseasonably cold weather expected across MISO

WARNINGS

Maximum Generation Warning (South)
DEC 23, 9:15 a.m. – 12:45 p.m. EST

Conservative Operations (South)
DEC 23, 9:15 a.m. EST –DEC 26, midnight EST

Tightened conditions due to unit trips and failures to start (~2 GW), higher-than-forecast South load (~2.5 GW), and reduced RDT flow limit N-S (to 1.5 GW)

Maximum Generation Warning (Footprint)
DEC 23, 4:30 p.m.

Conservative Operations (Footprint)
DEC 23, 9 p.m. EST –DEC 24, noon EST

Tighter conditions due to higher-than-forecast system-wide loads, forced outages driven primarily by fuel supply issues and units that failed to start

EVENTS

Maximum Generation Event, Step 1b (Footprint)
DEC 23, 5:30 p.m.

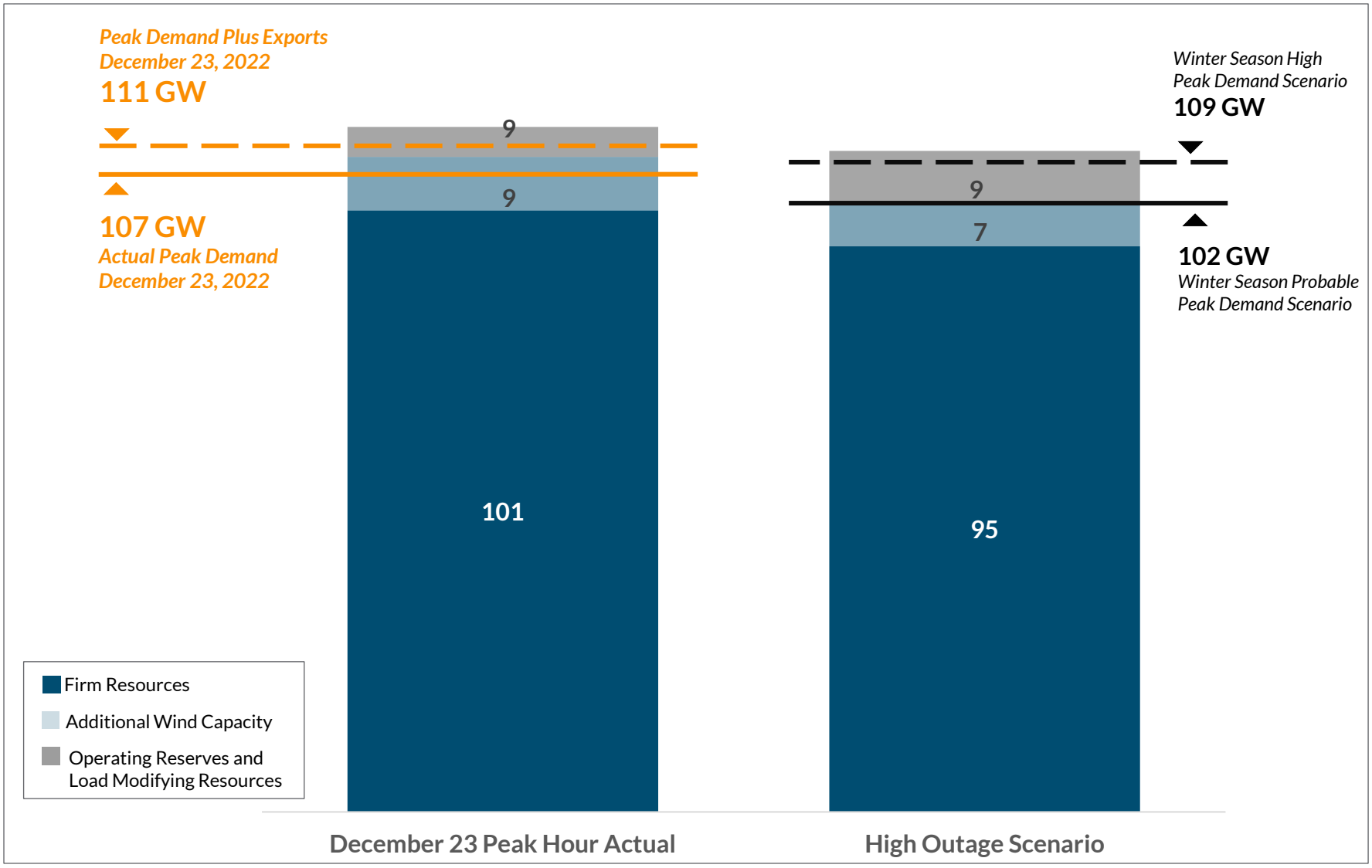
Tight conditions worsened with real-time transmission congestion and diminishing generation deliverability

Maximum Generation Event, Step 2a (Footprint)
DEC 23, 6 p.m. – 9 p.m. EST

Emergency procedures allowed access to demand response, which reduced the peak demand

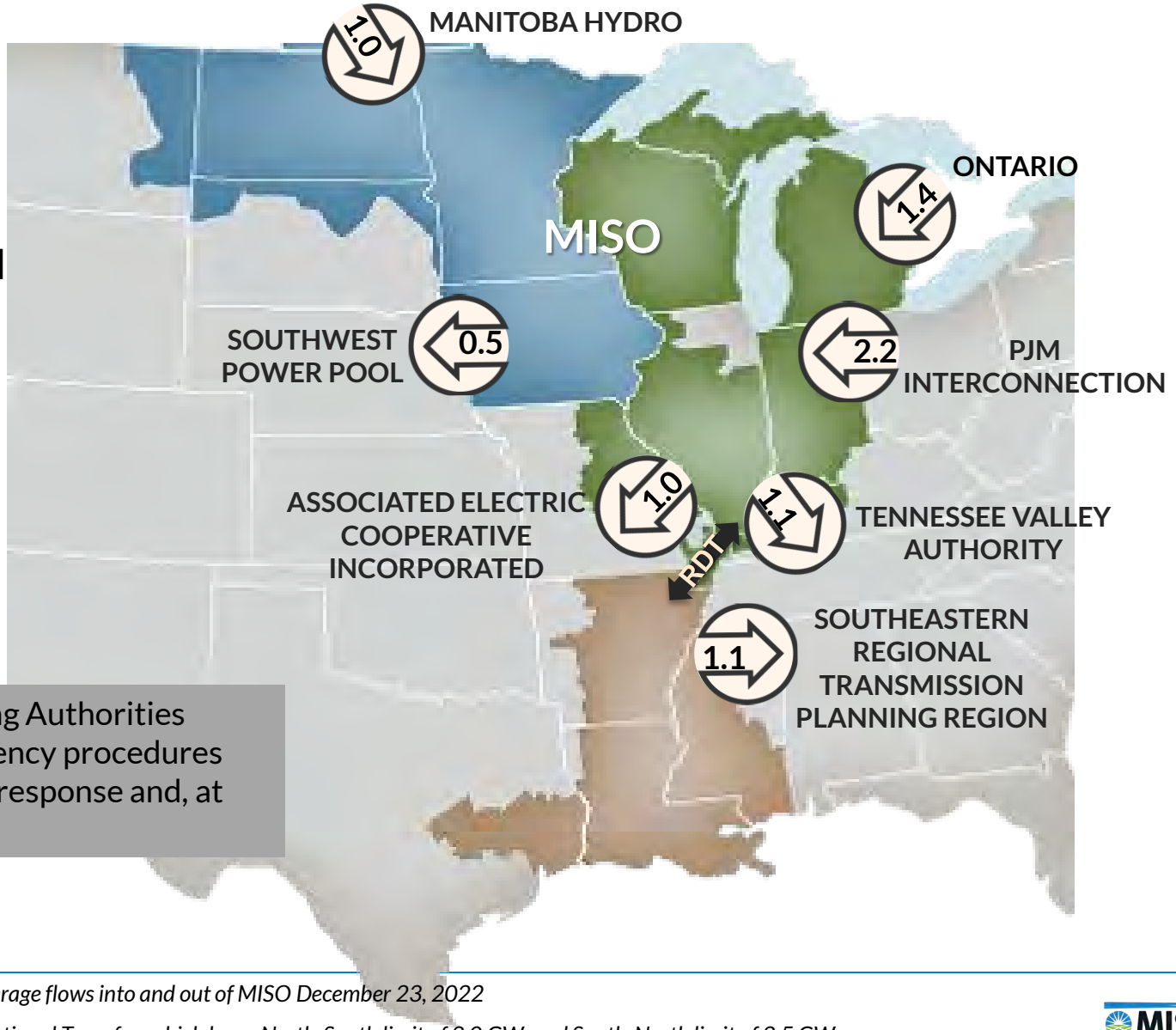
Note: All times indicate the effective time of each declaration

Reserve capacity was closely monitored, and exports would have been curtailed if conditions had worsened



MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW

Net Scheduled Interchange (GW)

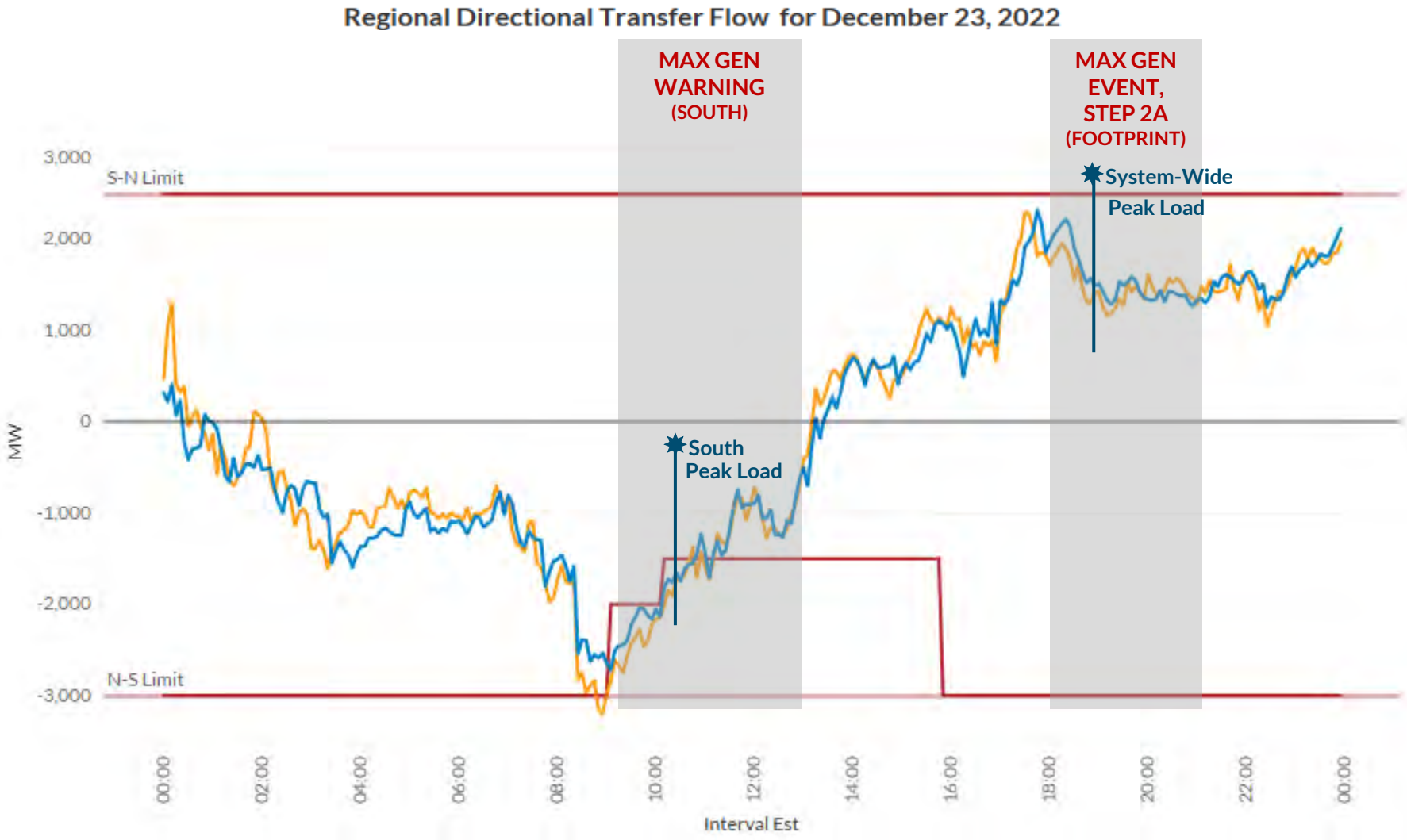


Multiple Balancing Authorities employed emergency procedures utilizing demand response and, at times, load shed

Image represents average flows into and out of MISO December 23, 2022

RDT = Regional Directional Transfer, which has a North-South limit of 3.0 GW and South-North limit of 2.5 GW

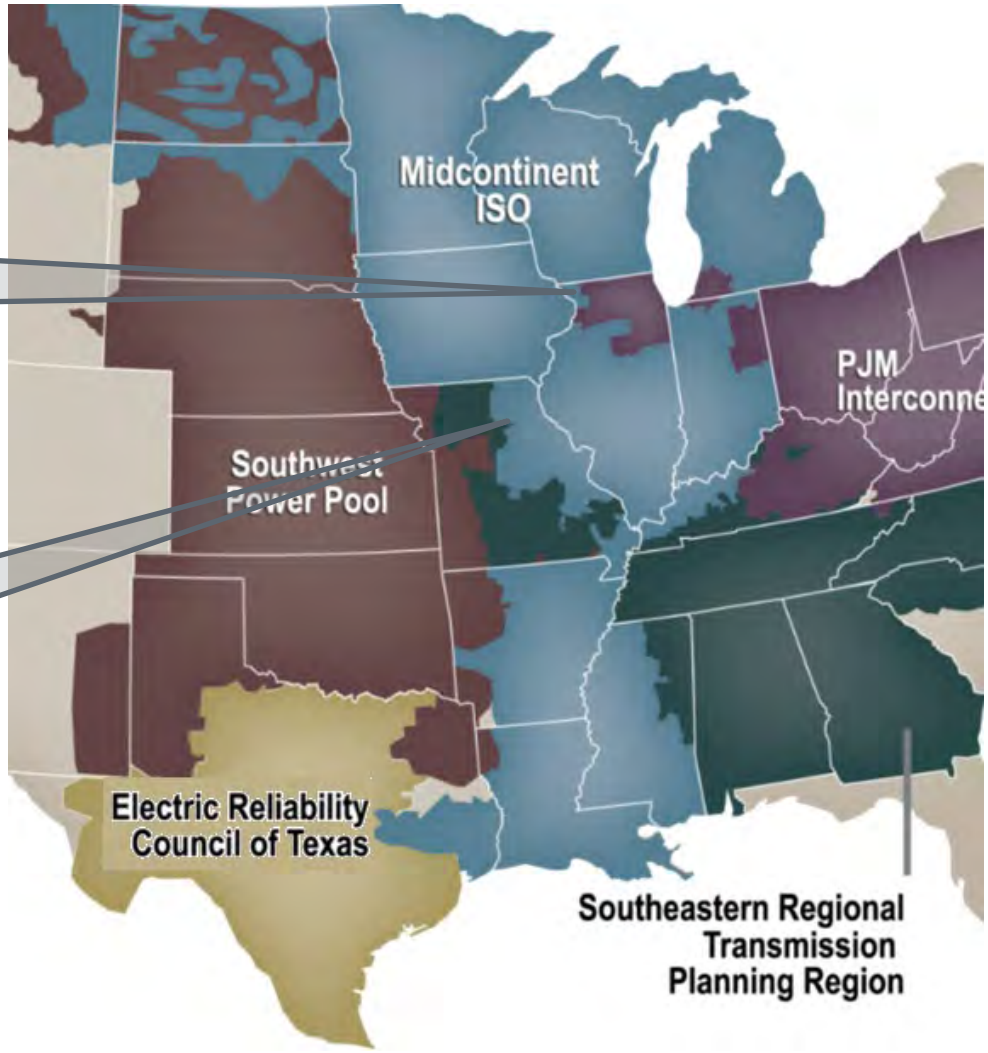
MISO complied with Joint Parties requests to reduce flows by 1,500 MW during the morning peak, which contributed to an emergency declaration in the South and a recall of non-firm exports



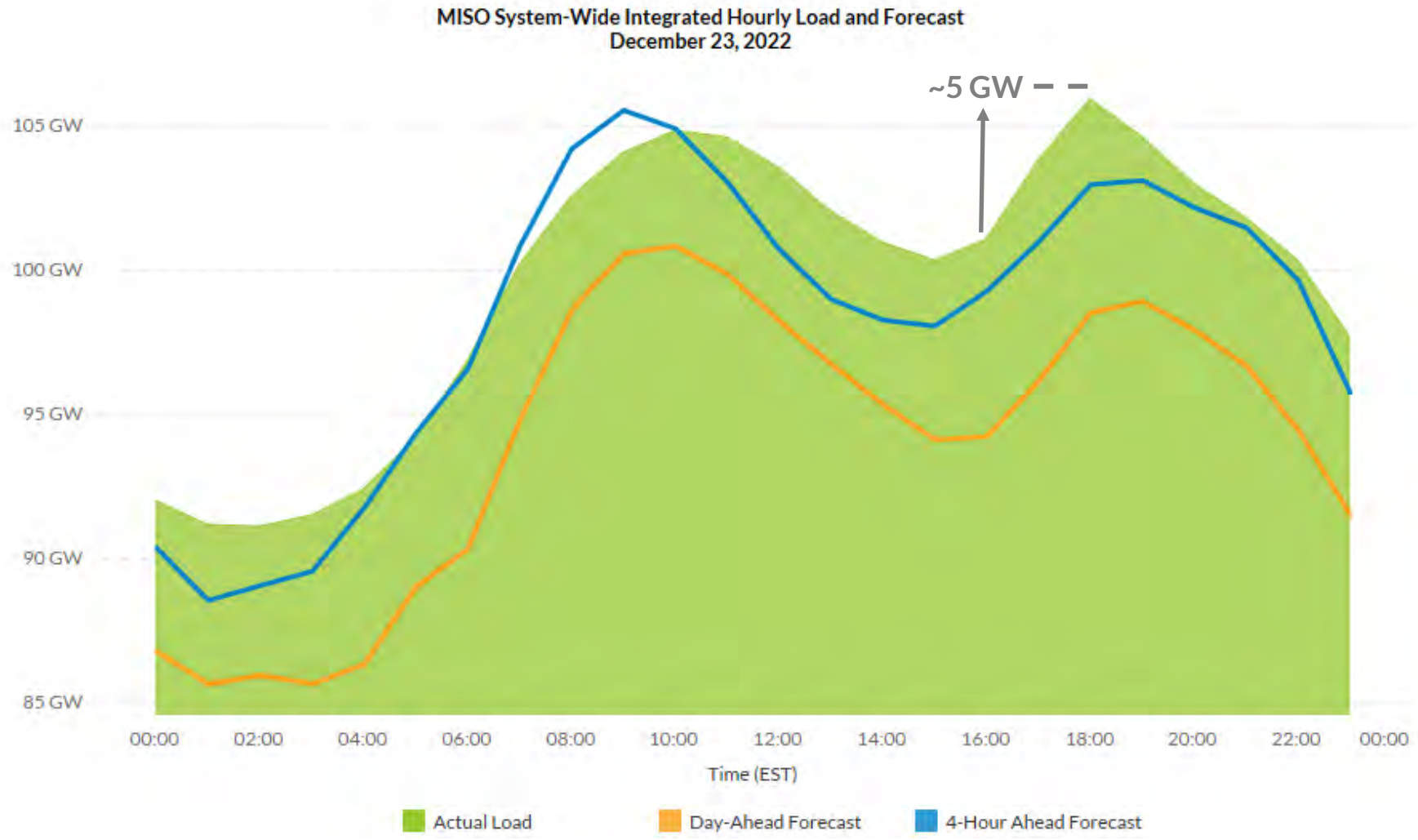
Two local transmission emergencies were declared to manage severe congestion on transmission lines

Local Transmission Emergency
SE Wisconsin
6:45 p.m. – 8 p.m. EST
December 23
(No customer interruptions)

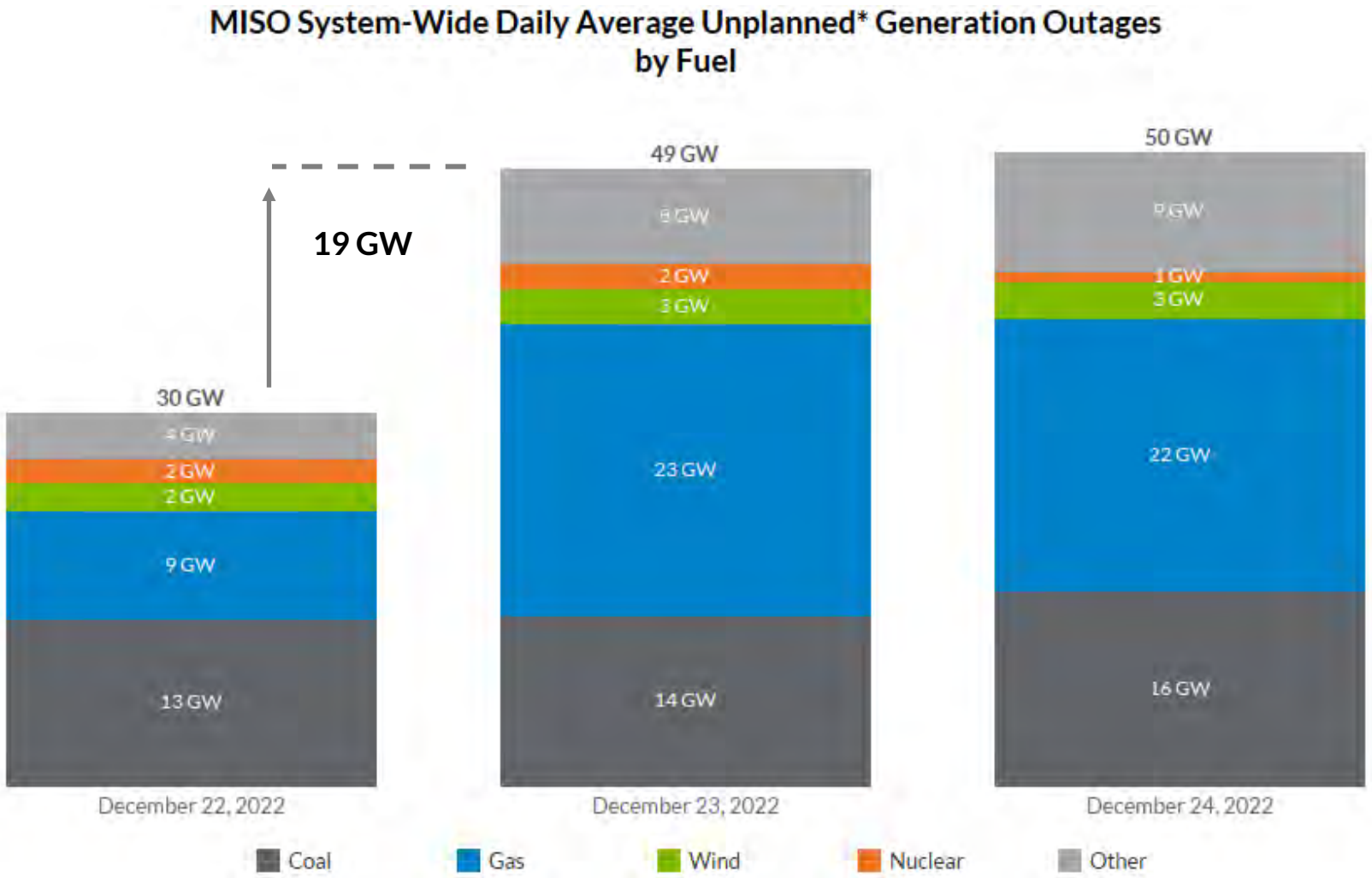
Local Transmission Emergency
Central Missouri
6:27 p.m. – 8 p.m. EST
December 23
(No customer interruptions)



Abnormally high load forecasting errors occurred due to a lack of historical data for similar extreme conditions in December



Gas supply availability contributed to increased unplanned outages, particularly in the afternoon, that pushed MISO into emergency procedures

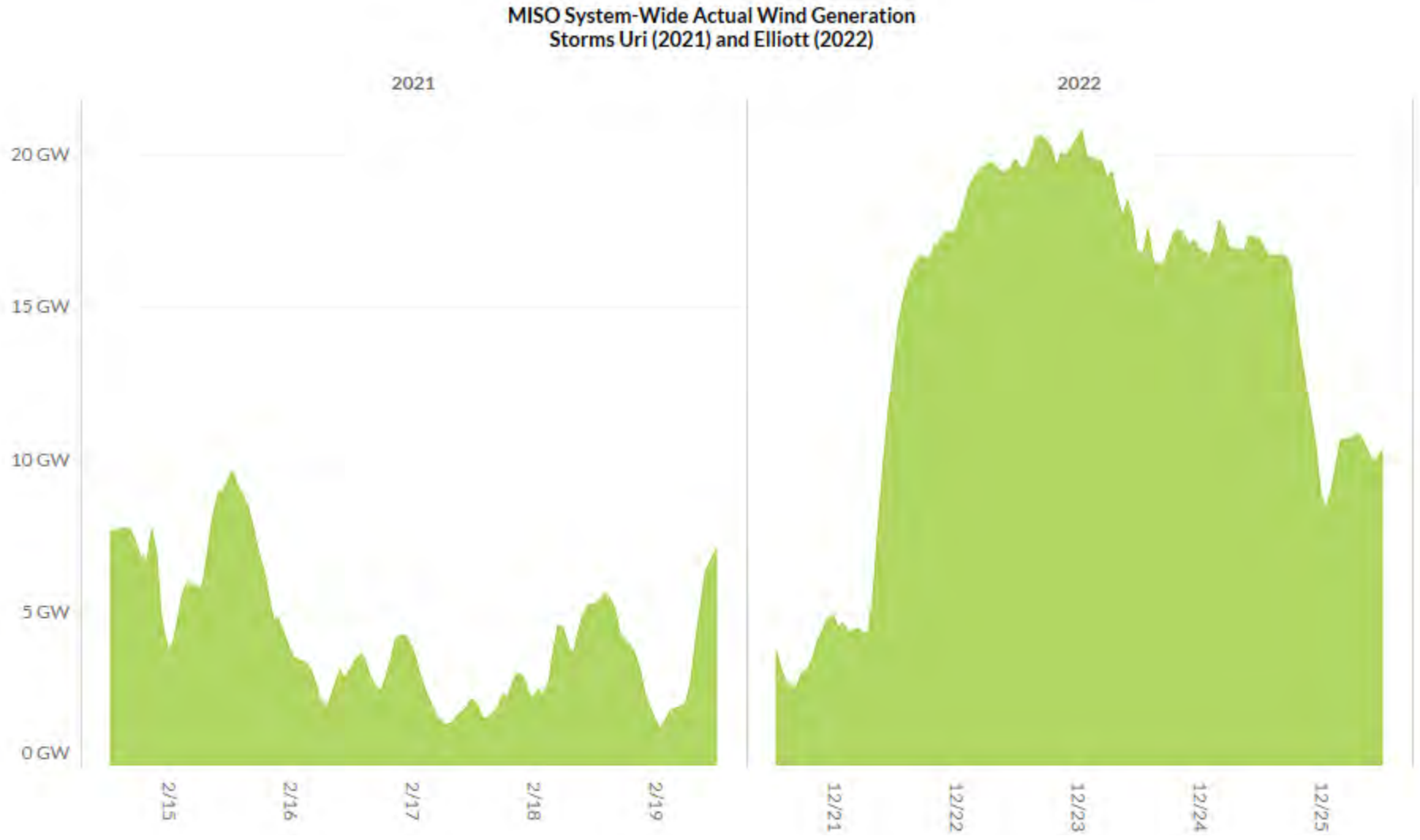


*Unplanned = forced outages and derates

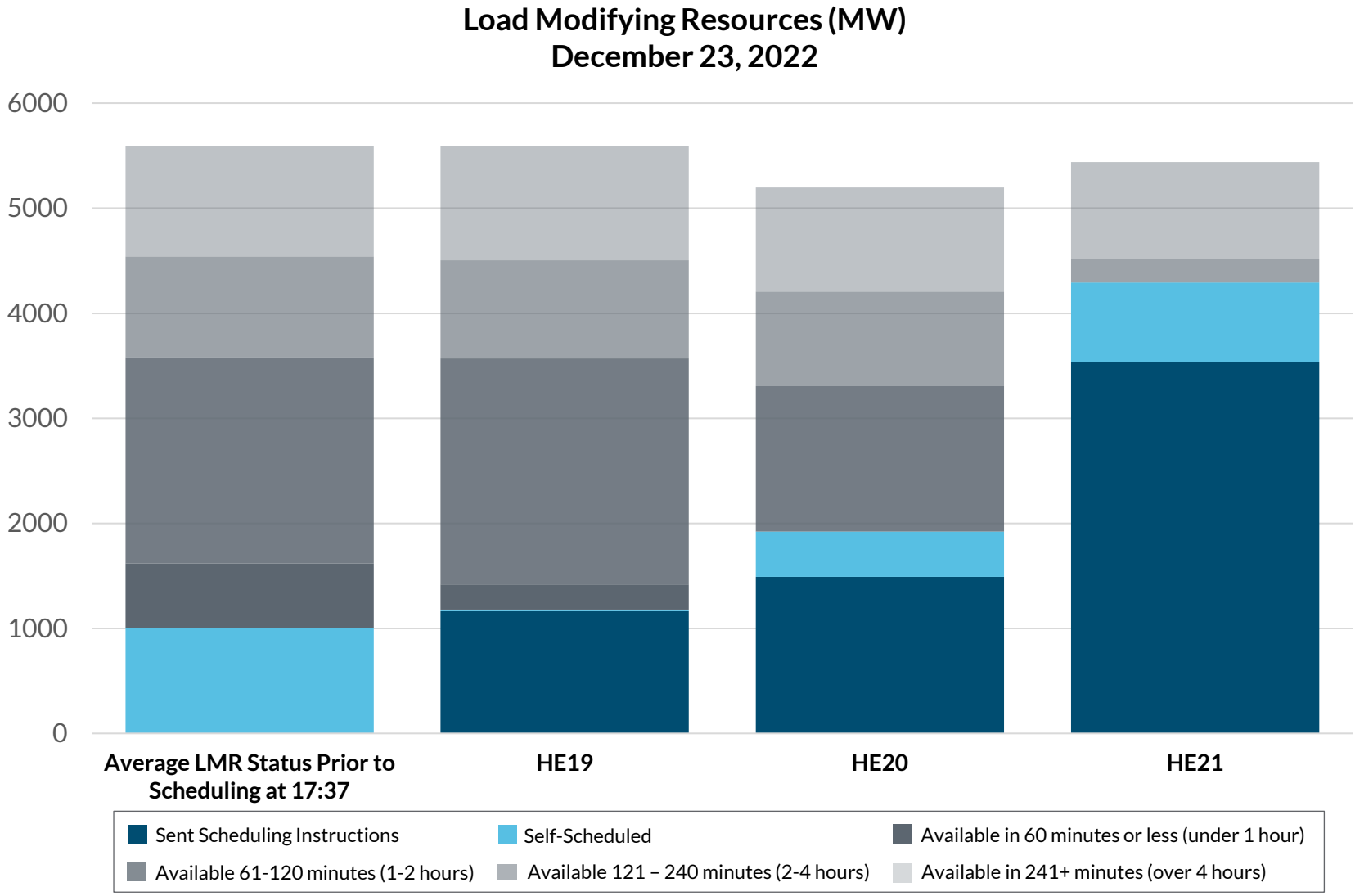
Charts reflect data in the CROW outage system on January 5, 2023

Wind often reported as derated over the time period

Wind production remained high during Winter Storm Elliott, providing support to the transmission system



Requested 3 GW of Load Modifying Resources at 17:37 to meet increasing load and continue exports to neighbors



While each storm is unique, lessons learned from Winter Storm Uri in 2021 contributed to successful operations during Elliott

REFINED WINTER READINESS ACTIVITIES

- Increased focus on extreme scenarios
- Improved understanding of generator winter preparedness through coordinated seasonal assessment and fuel and consumables data requests
- Implemented cold weather-specific operator drills in addition to emergency procedure drills and winter readiness workshops

PROCESS IMPROVEMENTS

- Process Improvements to Unit Commitment Processes and Operator Situational Awareness improved our ability to respond to changing risk profile during the operating day

IMPROVED COORDINATION

- Improved coordination activities with our neighbors that resulted in quicker decision making during the storm

View the complete February Arctic Event report on the MISO website

Appendix

MISO's operating procedures ensure reliability and gain access to additional resources during extreme situations

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

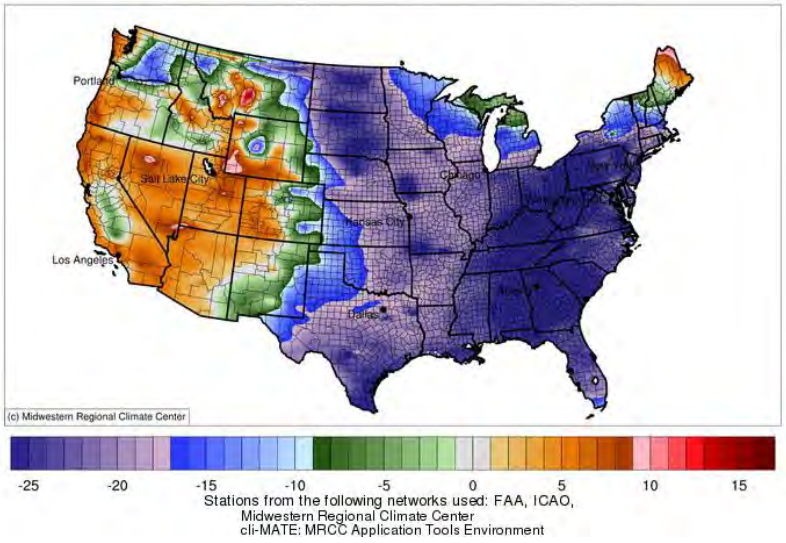
Normal Operations		Normal Pricing
Capacity Advisory	Advance notice of forecasted capacity shortage, requests Stakeholders update offer data	
Alert	Define boundaries/suspend maintenance	Emergency Pricing Tier 0
Warning	Schedule in external resources, curtail export transactions, activate reconfiguration	Emergency Pricing Tier I Offer Floor
Event Step 1	Commit emergency resources, declare NERC (Energy Emergency Alert) EEA 1, activate emergency limits	
Event Step 2	Declare NERC EEA 2, implement Load Modifying Resources (LMRs), Load Management Measures (LMMs) Stage 1, commit Emergency Demand Response (EDR) resources, emergency energy purchases, public appeals	Emergency Tier II Offer Floor
Event Step 3	Utilize operating reserves and LMMs Stage 2	
Event Step 4	Reserve call and emergency reserve purchases	
Event Step 5	Declare NERC EEA 3, firm load shed, and set Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to the VOLL	Value of Lost Load (VOLL) Pricing
Termination	Terminate Max Gen and possibly Capacity Advisory	Normal Pricing

Data Source: SO-P-EOP-00-002 Rev 14 MISO Market Capacity Emergency

Winter Storm Elliott continued to impact the Eastern Interconnect through December 25

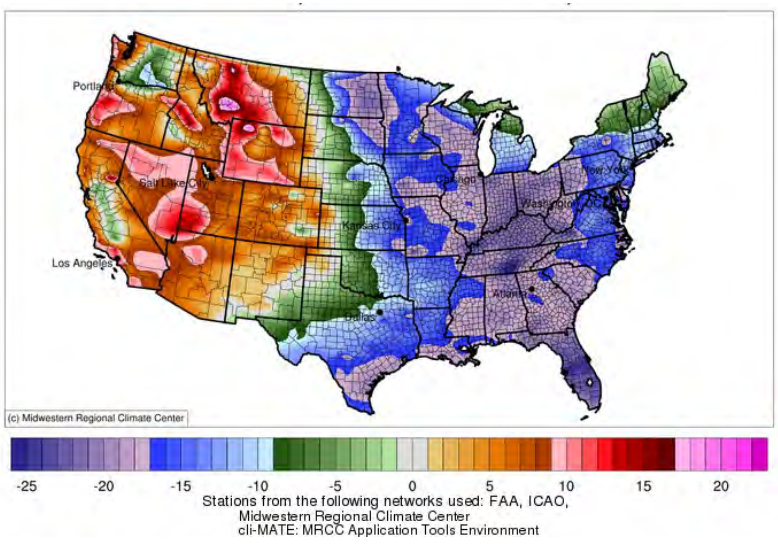
WINTER STORM ELLIOTT DECEMBER 24, 2022

Average Temperature:
Departure from 30-Year Normal

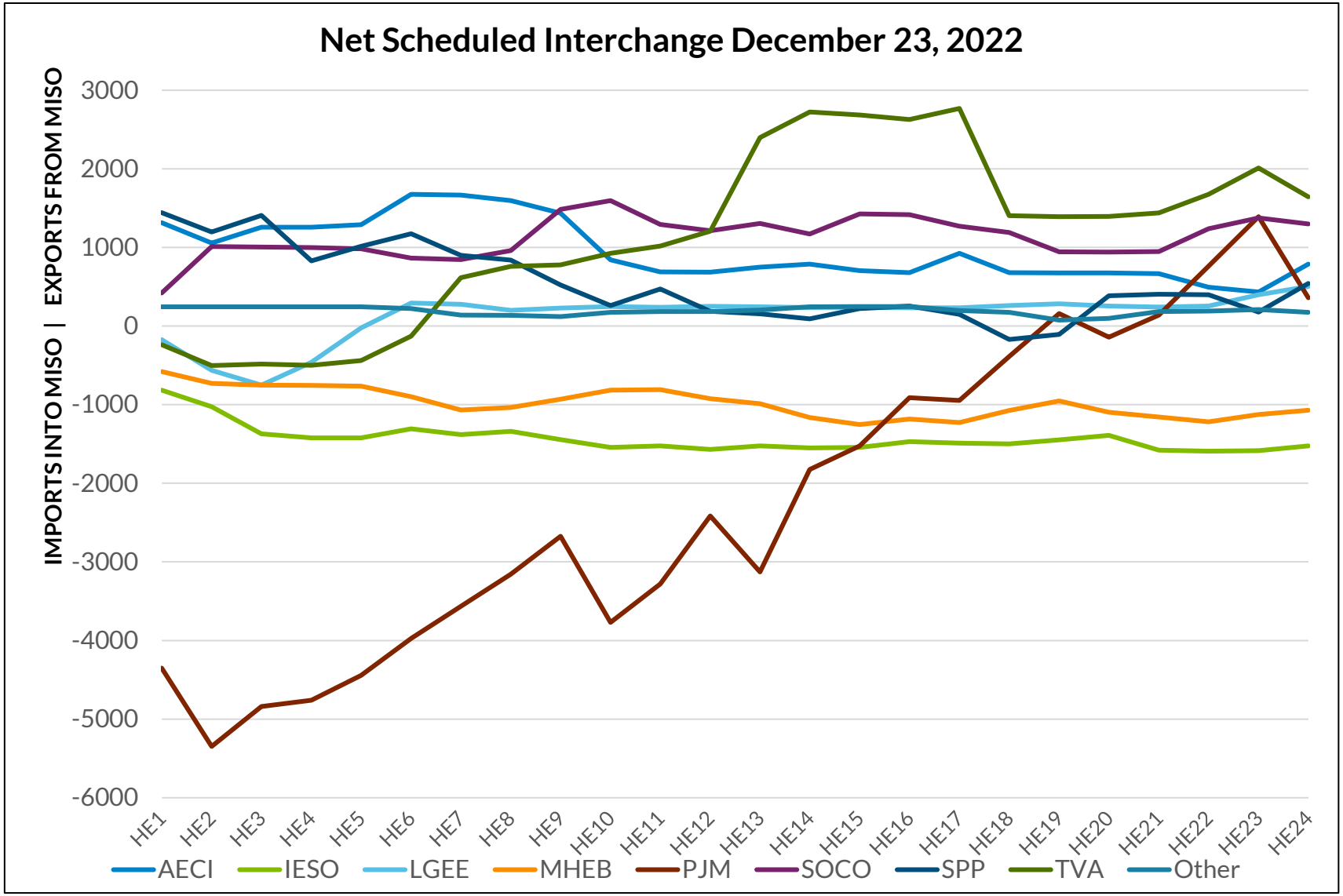


WINTER STORM ELLIOTT DECEMBER 25, 2022

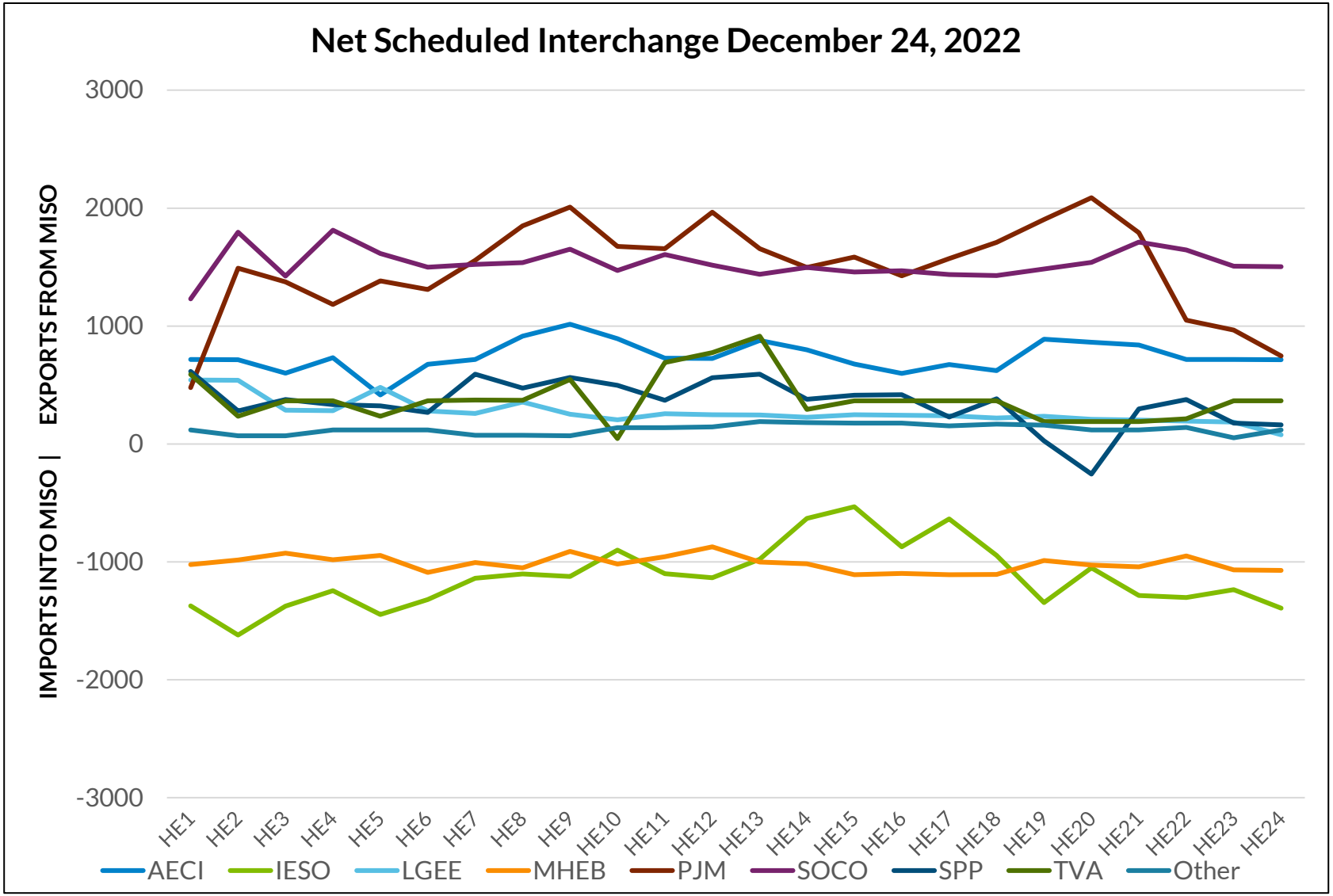
Average Temperature:
Departure from 30-Year Normal



MISO maintained its support for neighbors December 23-24



MISO maintained its support for neighbors December 23-24



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 37

MISO 2025-2026 CIL/CEL Final Results

2025-2026 PY Seasonal CIL/CEL Final Results

LOLE Working Group

October 24, 2024

Corrected Slides 6 & 17
10/24/2024

Purpose & Key Takeaways

Purpose:

Present the final Seasonal CIL/CEL Results for Planning Year 2025-2026

Key Takeaways:

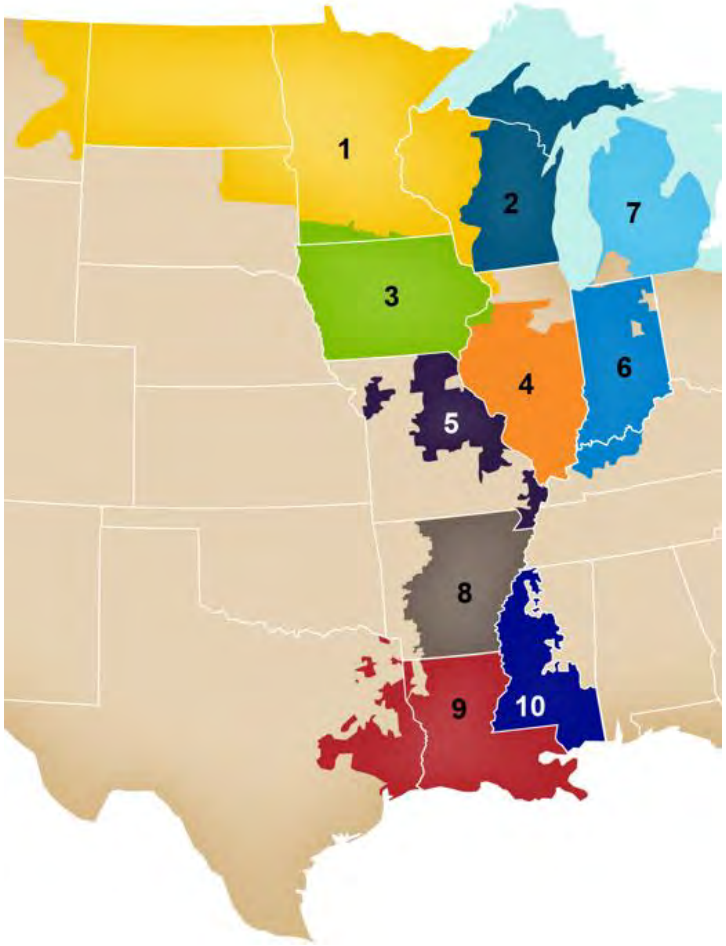
- Highlight and discuss changes between the preliminary and final results due to stakeholder feedback
  - Generation and load was adjusted in the Summer 2025 model in LRZ 3, which resulted in a rerun of the Summer 2025 CIL/CEL model for LRZs 1-7
  - Line ratings were adjusted in LRZ 6 (Gibson – Douglas – Francisco) in the Summer 2025 model and resulted in a rerun of the Summer 2025 model for LRZ 7
- Finalize Planning Year 2025-2026 CIL/CEL results. It is important to note that a change in Controllable Export amounts could adjust results before the March 2025 Planning Resource Auction

Changes between Preliminary Results and Final Results

Season	Preliminary	Final	Reason
Summer 2025 Zone 1 CIL	2,897	6,025	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CIL	4,200	4,370	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CIL	5,274	5,518	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CIL	8,542	8,649	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 5 CIL	3,403	4,117	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CIL	8,469	8,650	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CIL	2,973	3,579	Iowa LRZ 3 Load and Generation Update Gibson – Douglas – Francisco Line Rating Update
Summer 2025 Zone 1 CEL	3,418	3,991	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 2 CEL	4,954	4,614	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 3 CEL	1,272	4,655	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 4 CEL	3,751	4,460	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 6 CEL	6,866	6,881	Iowa LRZ 3 Load and Generation Update
Summer 2025 Zone 7 CEL	6,250	5,716	Iowa LRZ 3 Load and Generation Update

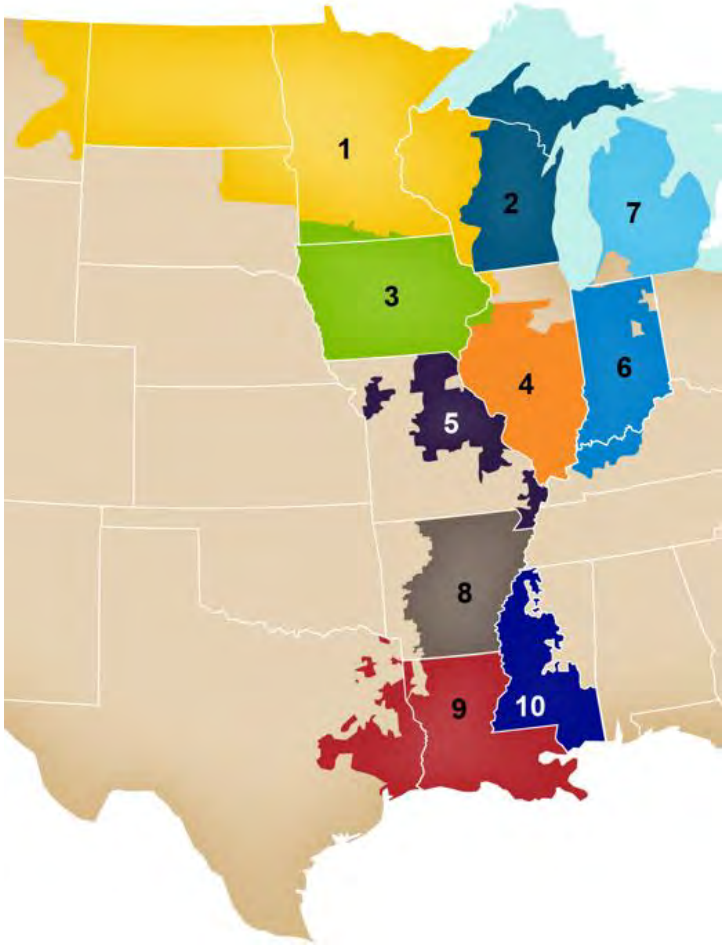
2025-2026 PY Zonal Import Ability Results

LRZ	Summer ZIA (MW)	Fall ZIA (MW)	Winter ZIA (MW)	Spring ZIA (MW)
1	6,023	5,688	5,575	6,396
2	4,370	6,537	6,435	6,439
3	5,460	7,704	5,785	7,726
4	7,757	7,013	6,457	7,373
5	4,117	4,679	4,922	4,453
6	8,366	8,672	7,690	9,176
7	3,569	5,115	4,762	5,166
8	2,358	5,675	3,432	6,085
9	4,361	4,741	4,418	4,855
10	4,474	4,508	3,458	4,365



2025-2026 PY Zonal Export Ability Results

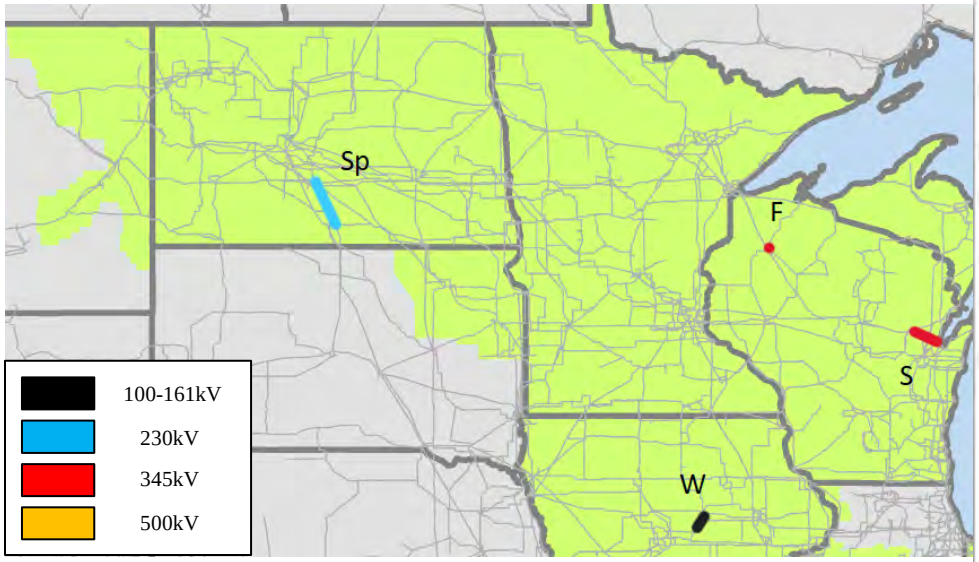
LRZ	Summer ZEA (MW)	Fall ZEA (MW)	Winter ZEA (MW)	Spring ZEA (MW)
1	3,993	6,167	3,593	5,285
2	4,614	4,259	4,793	6,119
3	4,713	5,924	7,480	6,039
4	5,352	5,069	5,531	5,880
5	3,939	5,816	4,814	5,797
6	7,165	5,471	1,911	6,706
7	5,726	5,168	5,712	5,499
8	6,509	4,219	3,783	3,724
9	4,286	4,173	3,618	4,146
10	2,097	3,164	2,028	3,072

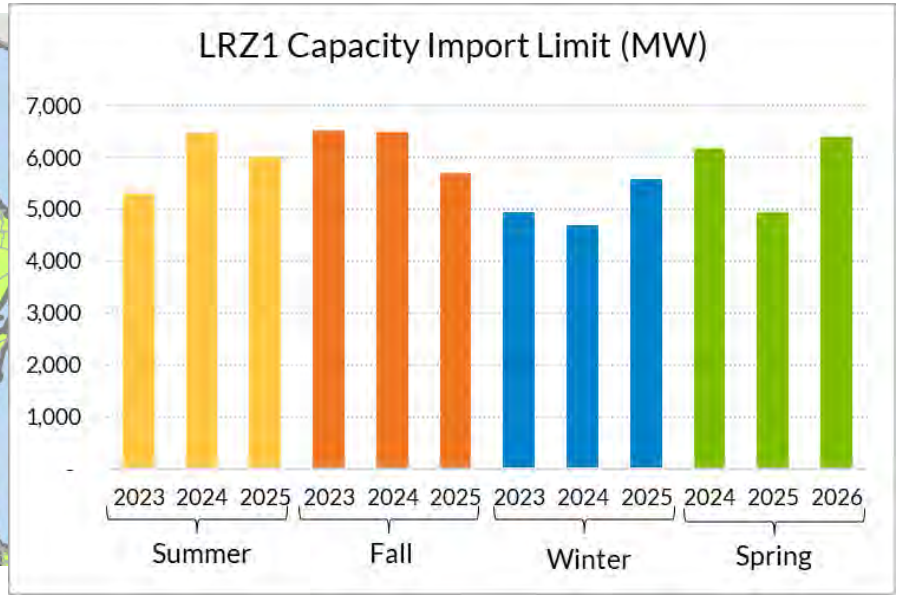


Planning Year 2025-2026 CIL Final Results

Capacity Import Limits
Zone 1: MN, MT, ND, SD and WI

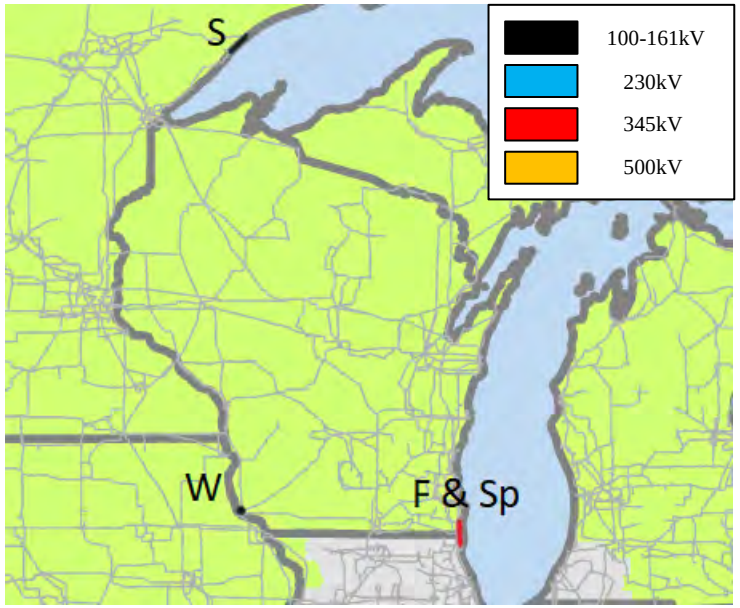
LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5575	5577
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398

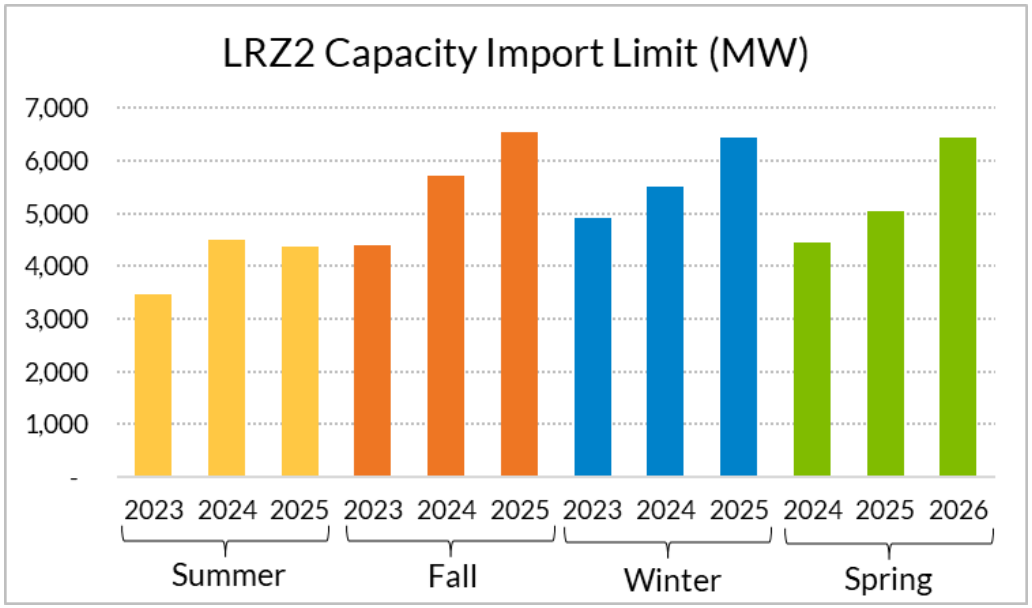




Capacity Import Limits
Zone 2: WI and MI

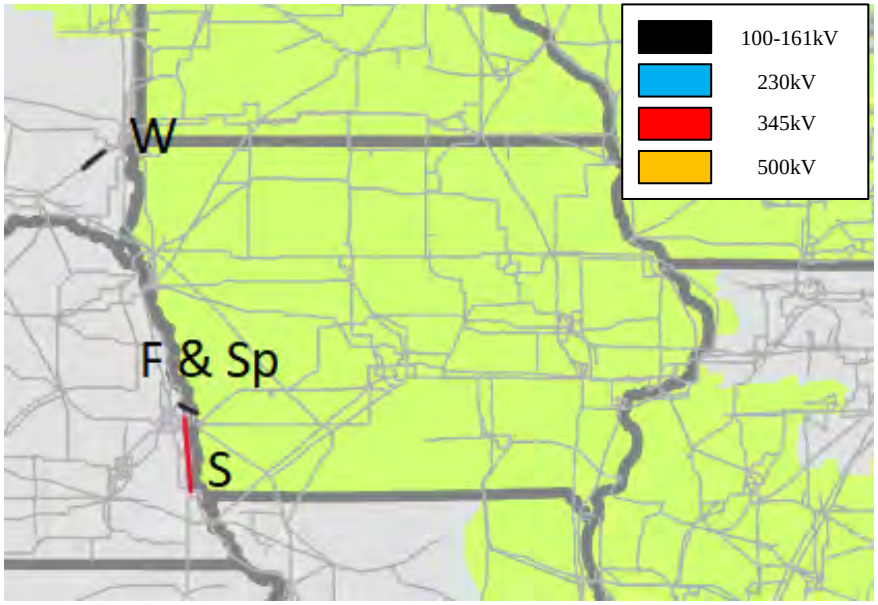
LRZ2	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439

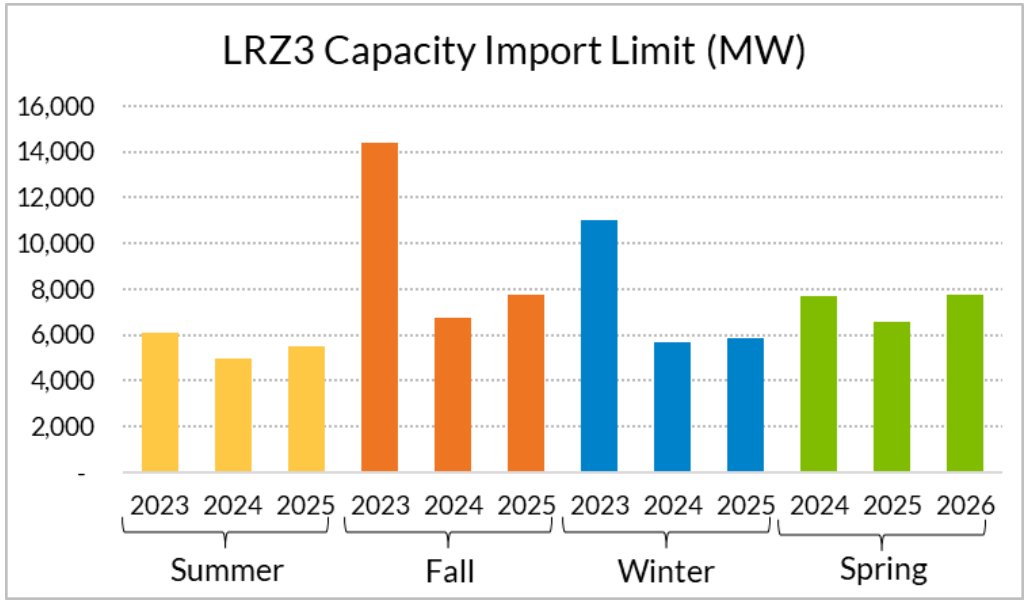




Capacity Import Limits
Zone 3: IA

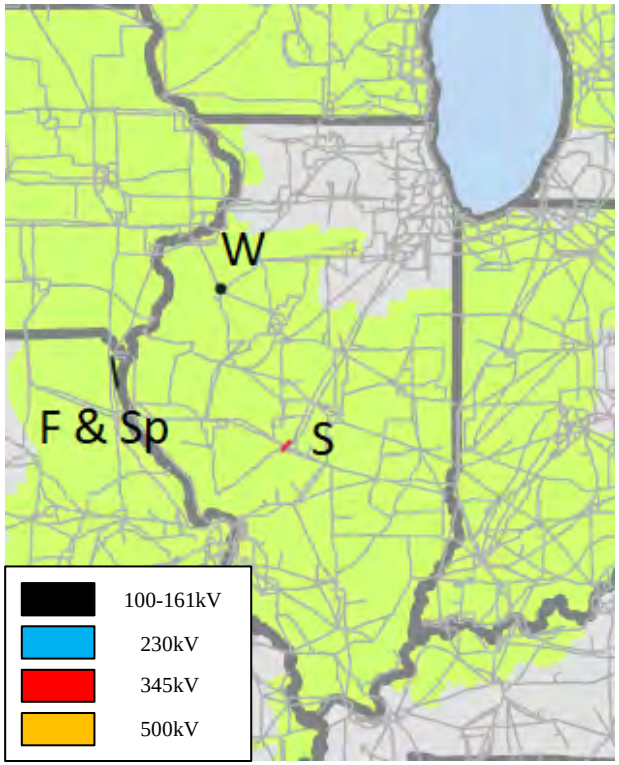
LRZ3	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784

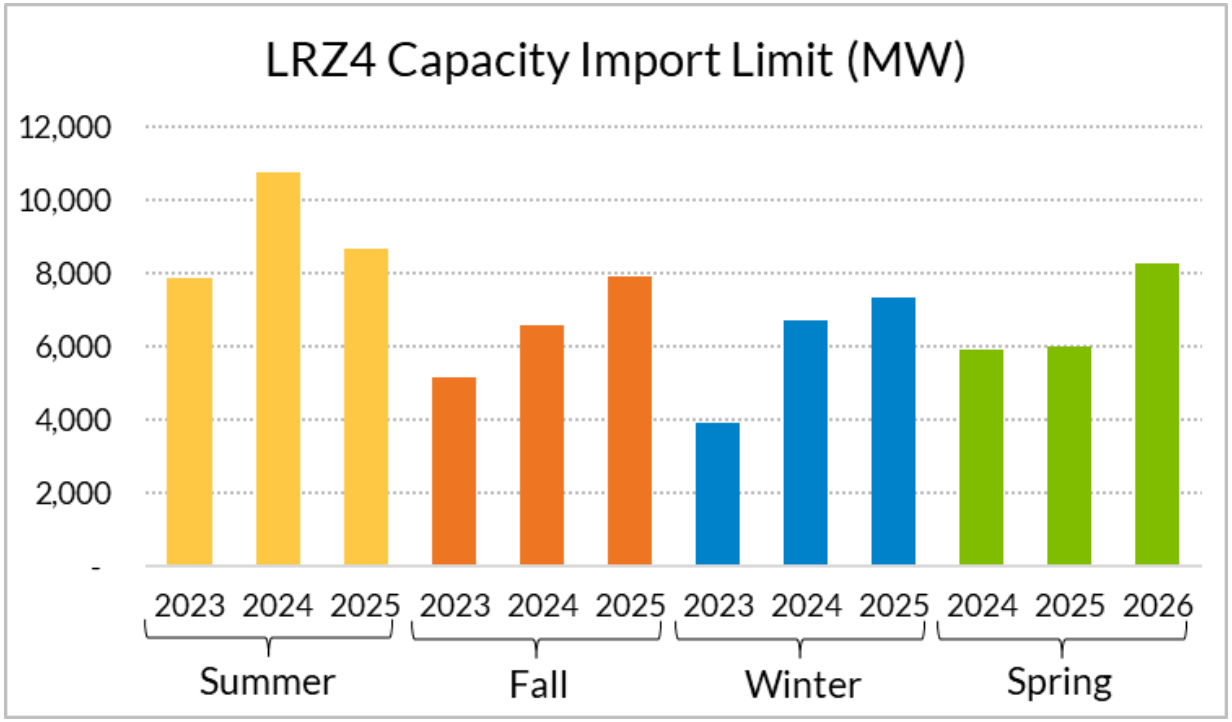




Capacity Import Limits
Zone 4: IL

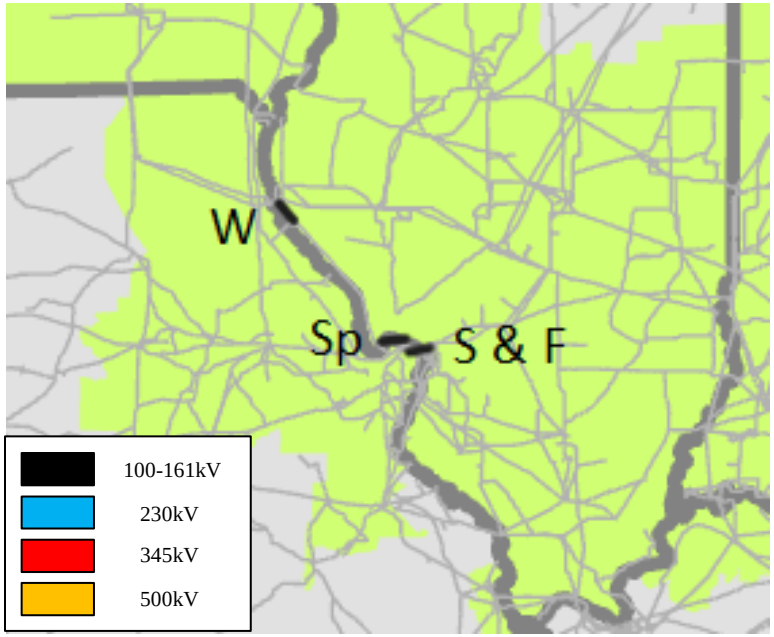
LRZ4	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272

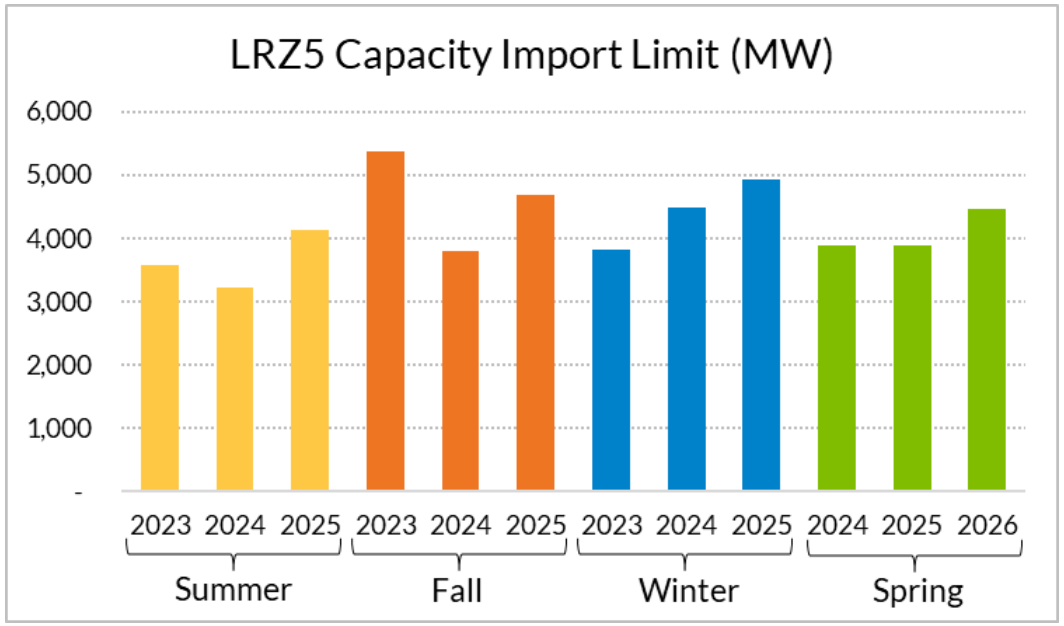




Capacity Import Limits
Zone 5: MO

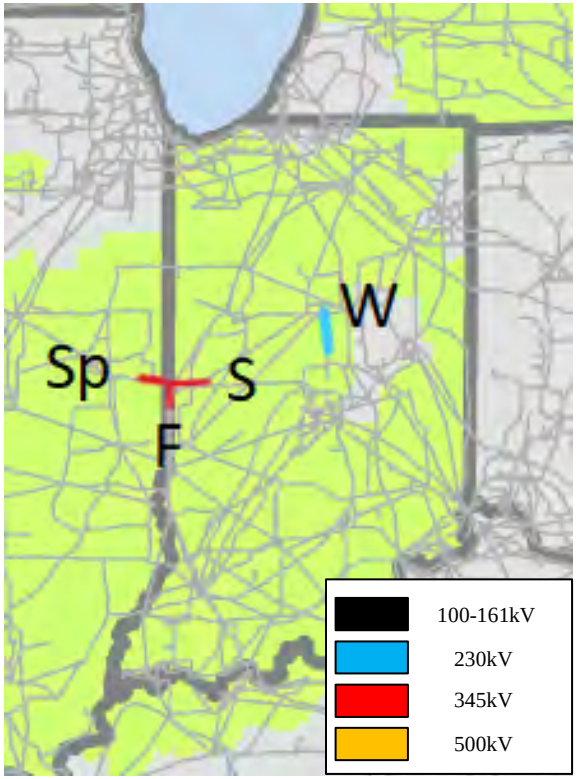
LRZ5	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453

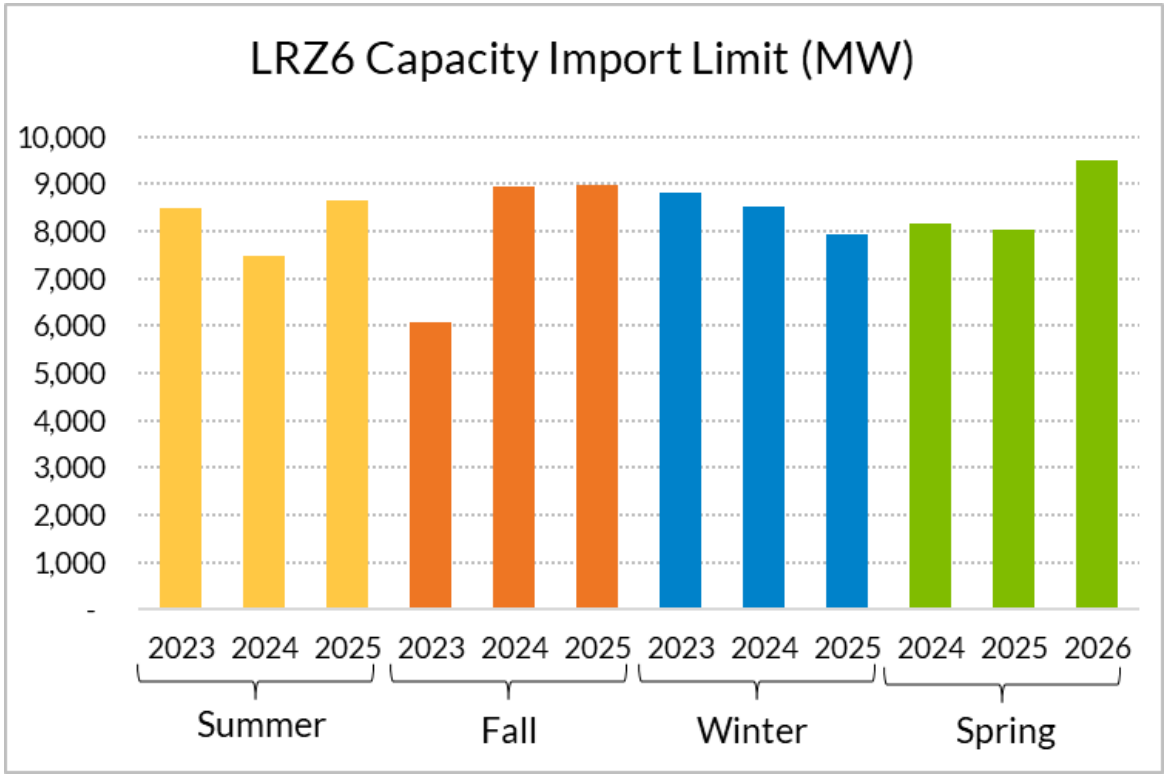




Capacity Import Limits
Zone 6: IN and KY

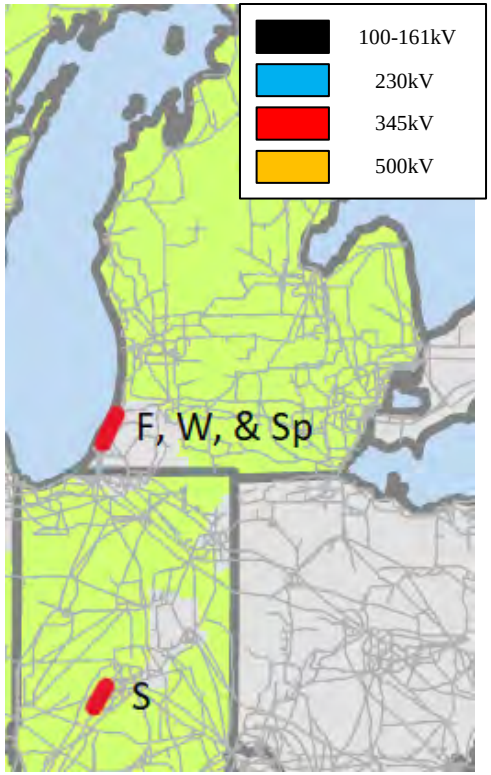
LRZ6	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491

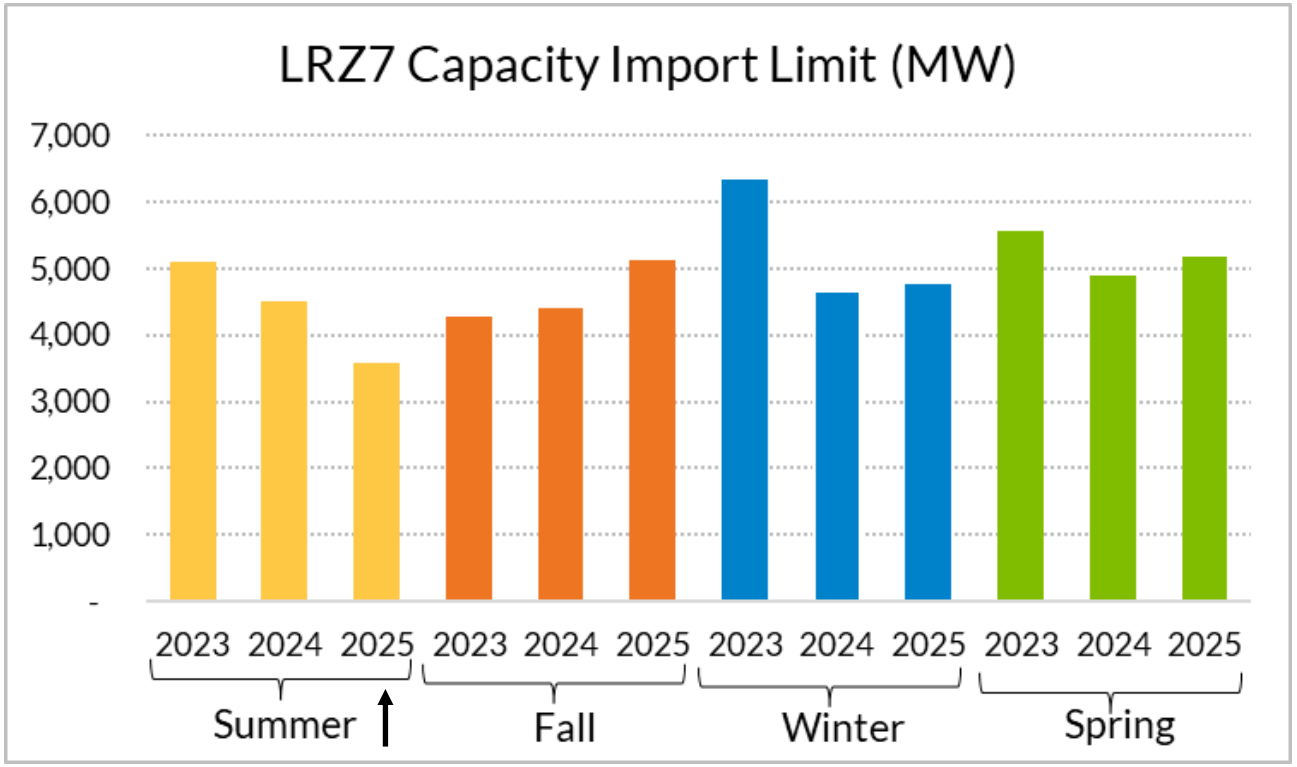




Capacity Import Limits
Zone 7: MI

LRZ7	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166

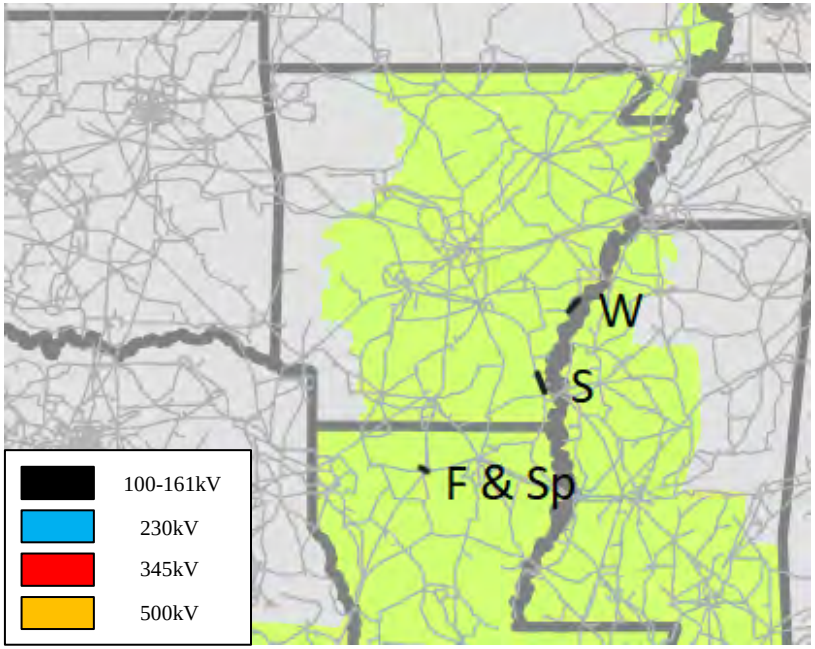


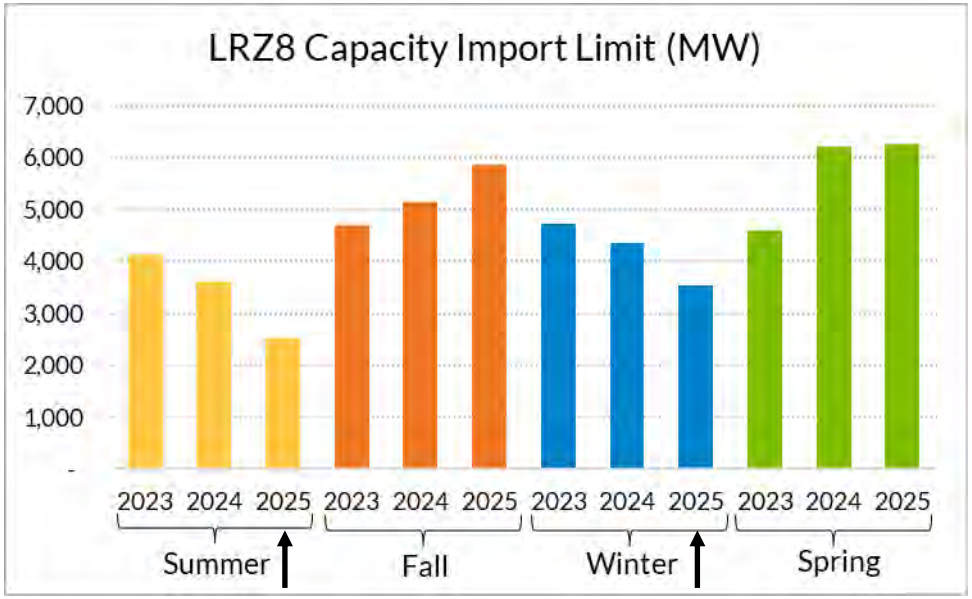


Primary Driver: Remaining resources binding earlier than previously due to lack of flexibility

Capacity Import Limits
Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250

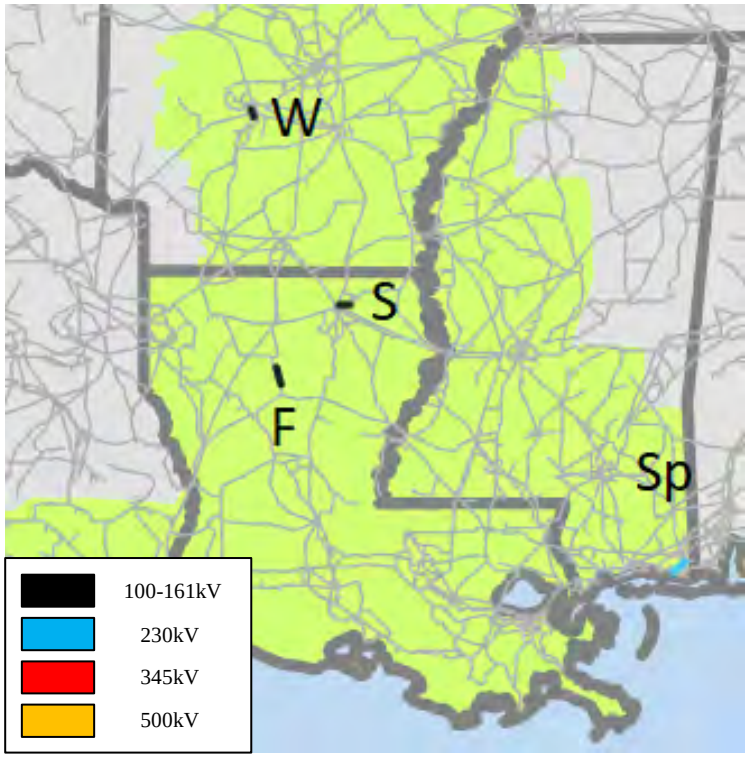


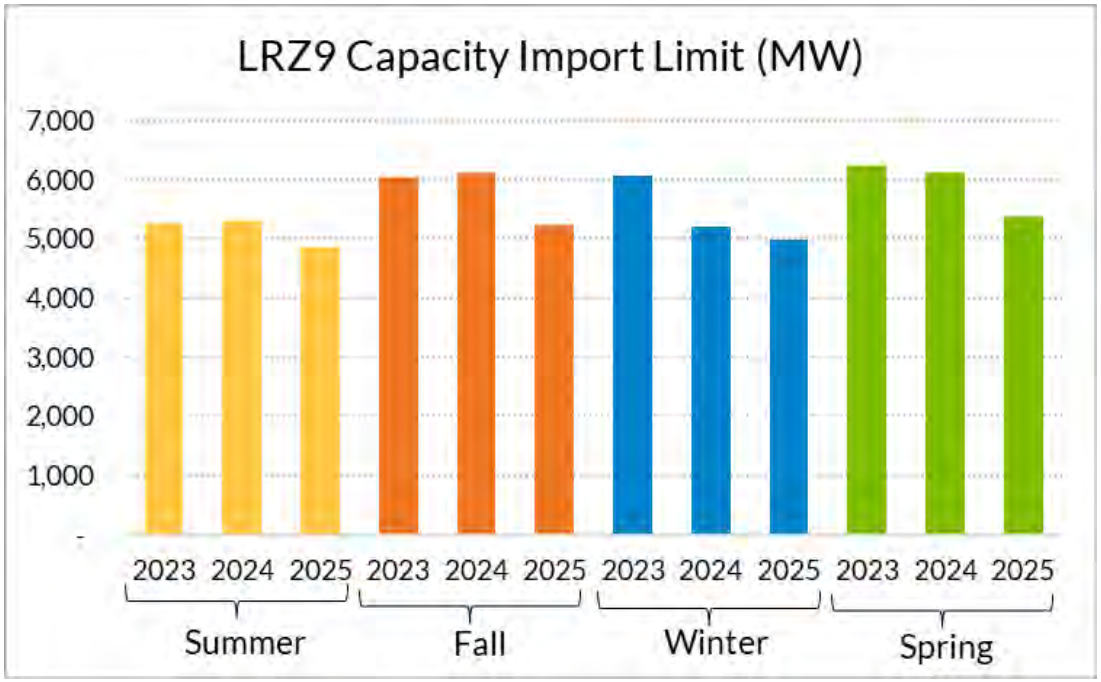


Primary Driver: New Resources are causing different flow patterns in base model, leading to earlier congestion

Capacity Import Limits
Zone 9: LA and TX

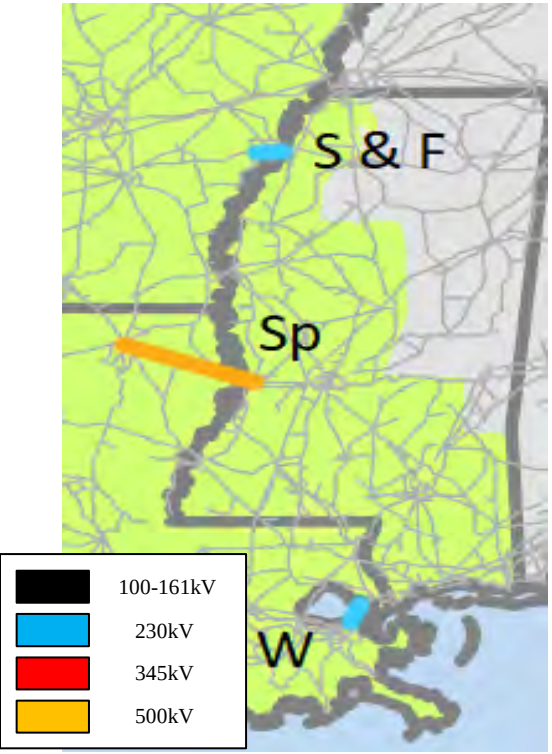
LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370

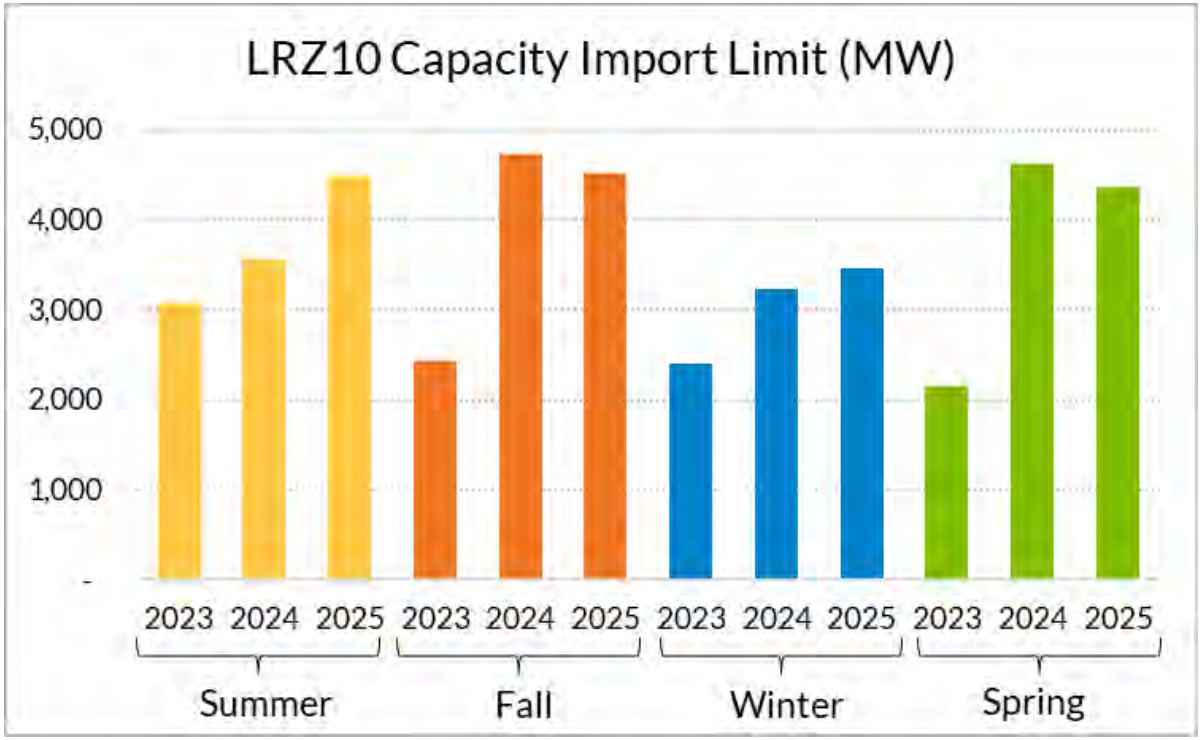




Capacity Import Limits
Zone 10: MS

LRZ 10	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

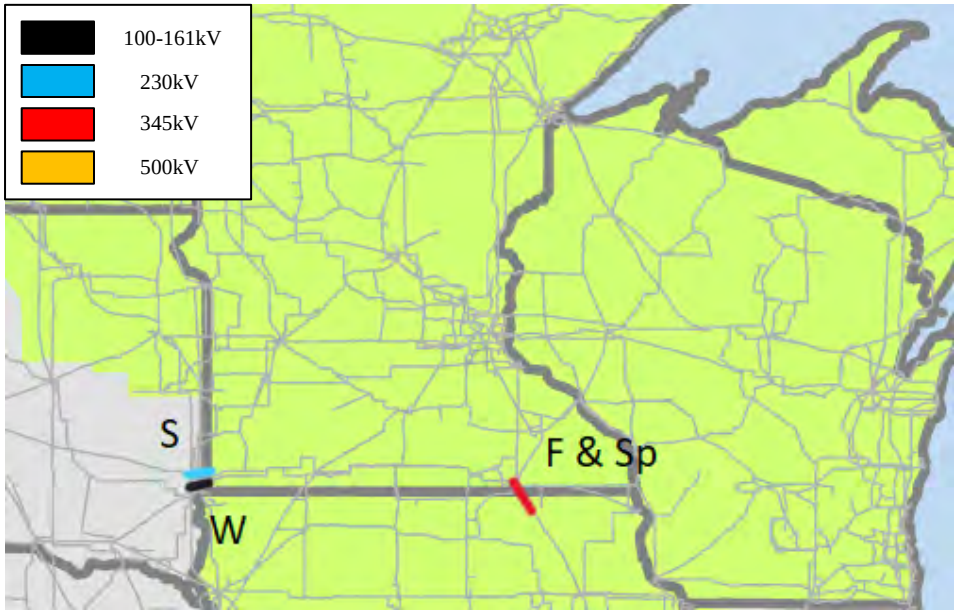


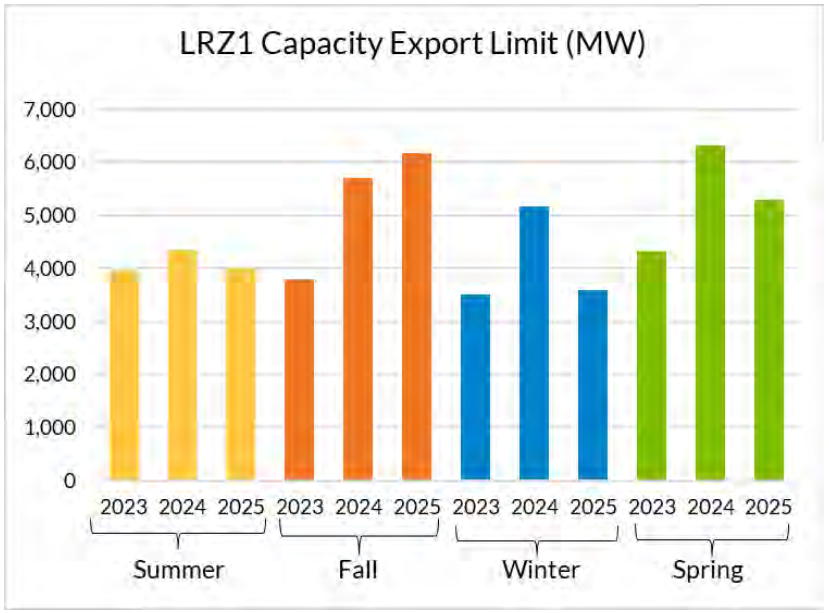


Planning Year 2025-2026 Final CEL Results

Capacity Export Limits
Zone 1: MN, MT, ND, SD and WI

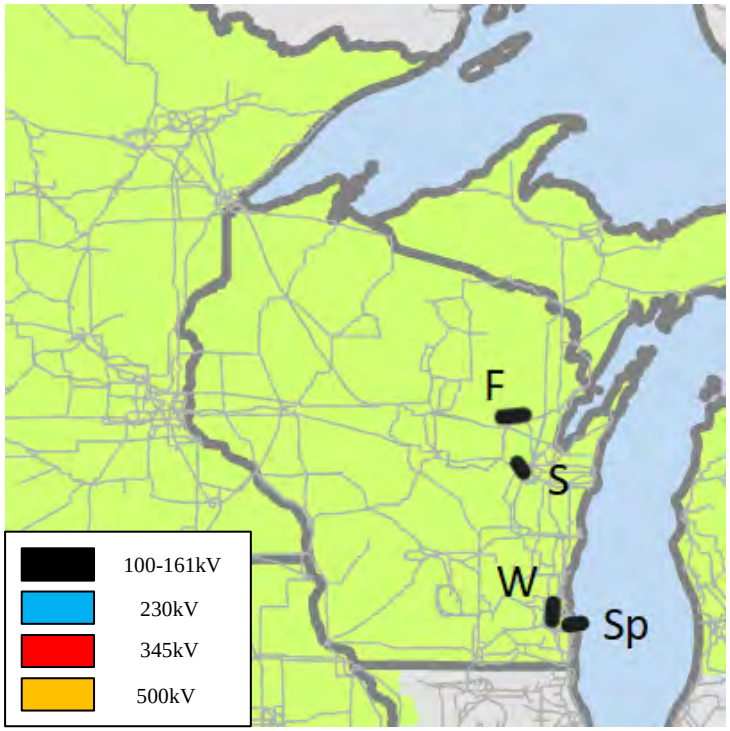
LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283

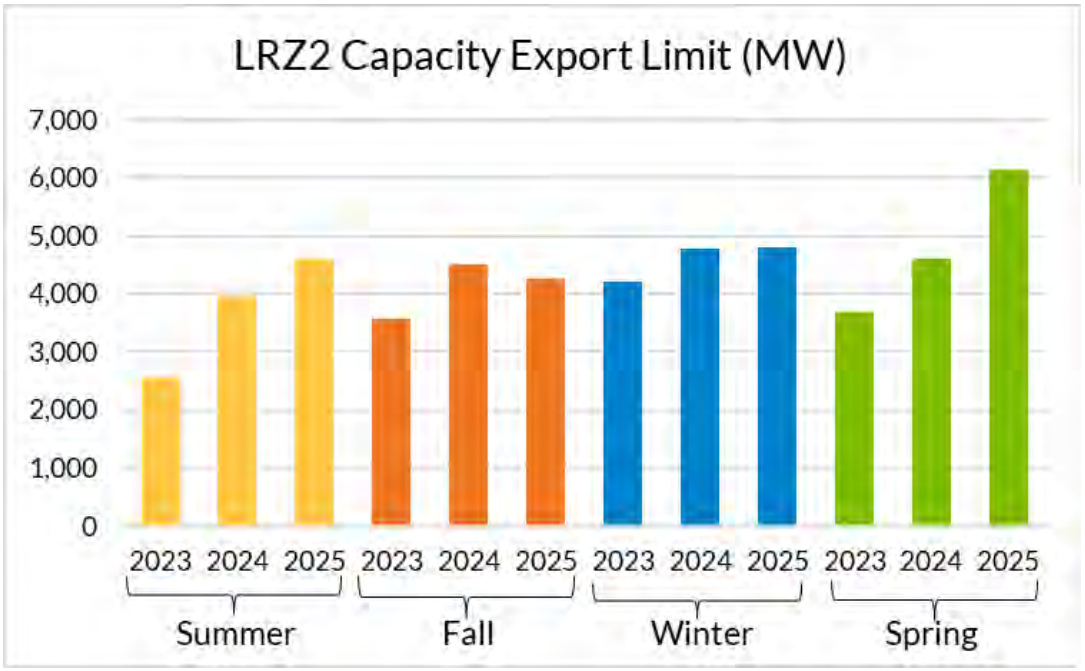




Capacity Export Limits
Zone 2: WI and MI

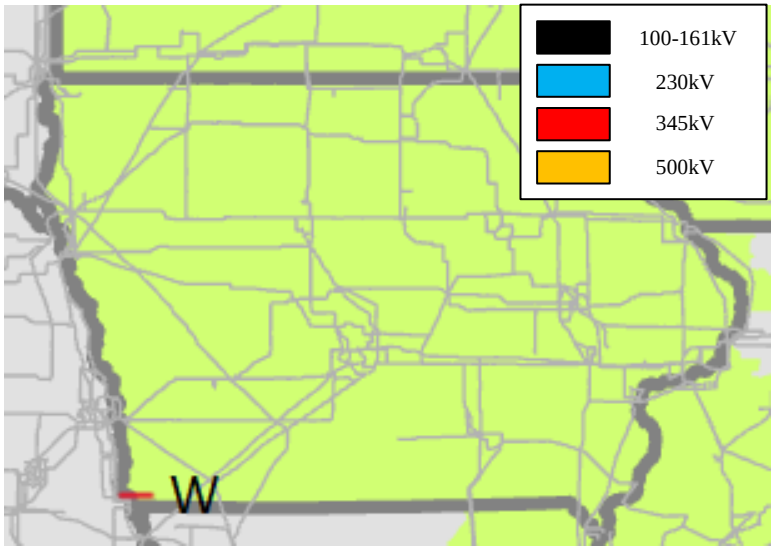
LRZ2	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119

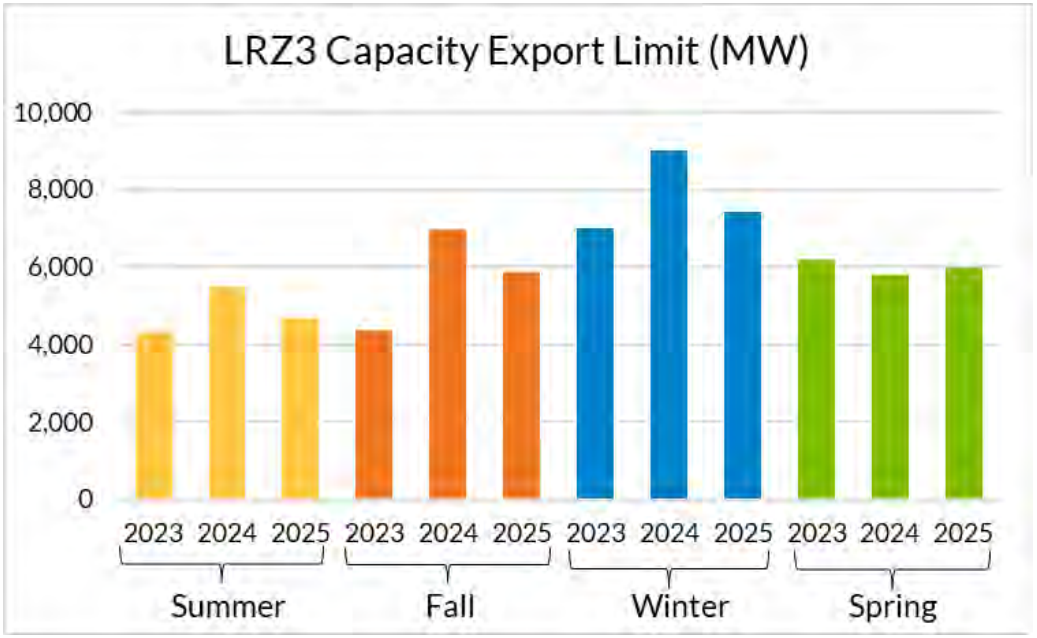




Capacity Export Limits
Zone 3: IA

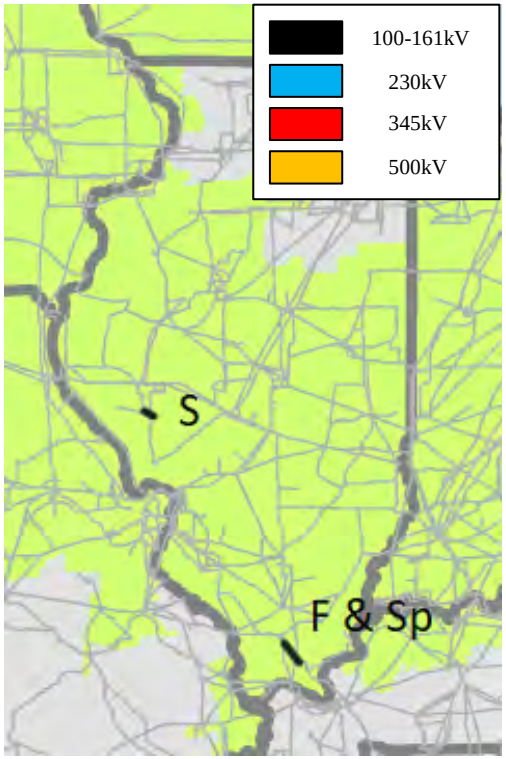
LRZ3	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981

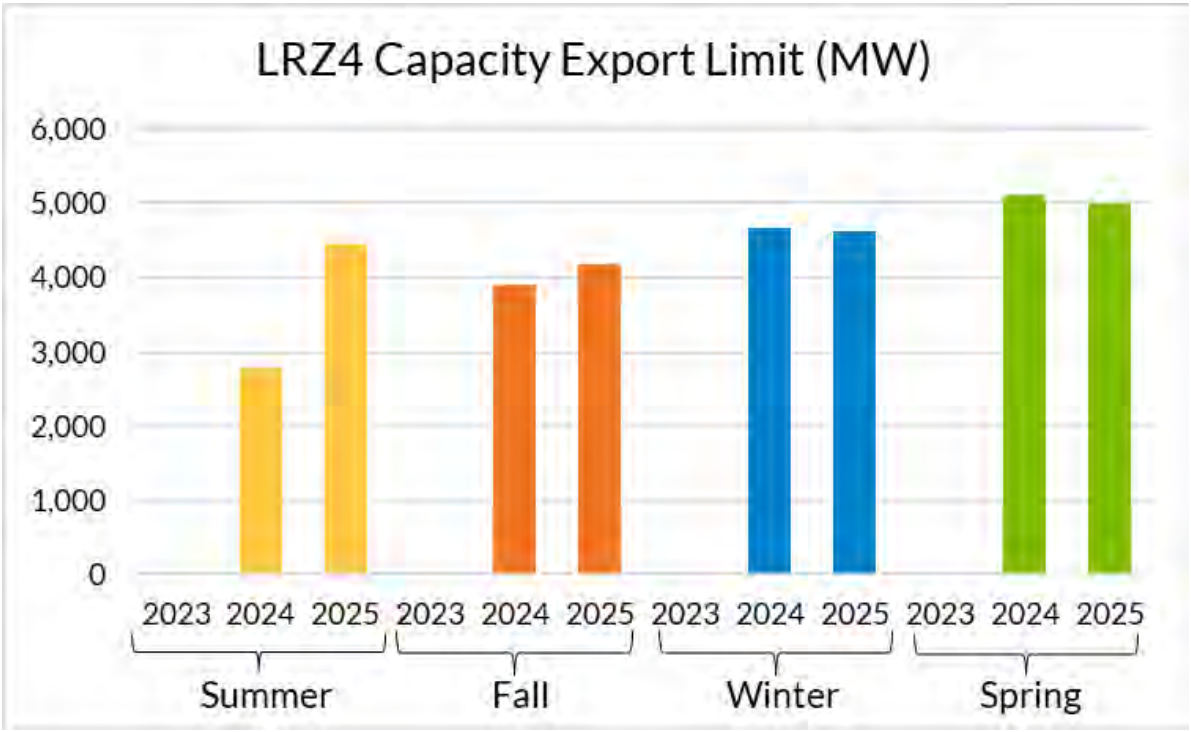




Capacity Export Limits
Zone 4: IL

LRZ4	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981





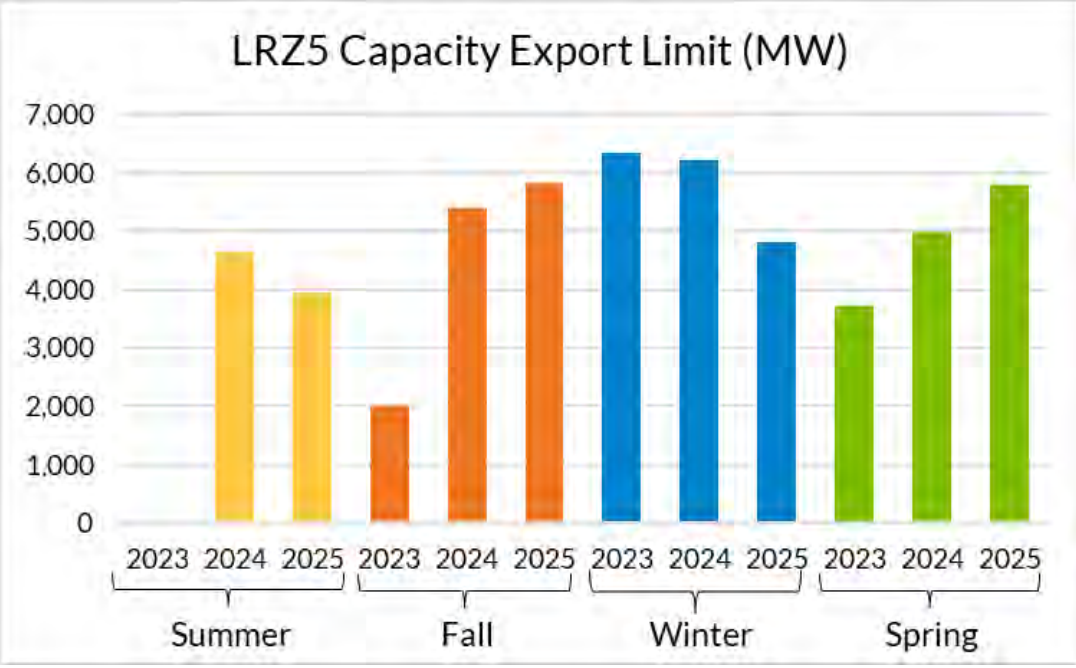
Capacity Export Limits
Zone 5: MO

LRZ5	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797

Limit: No Limit Found

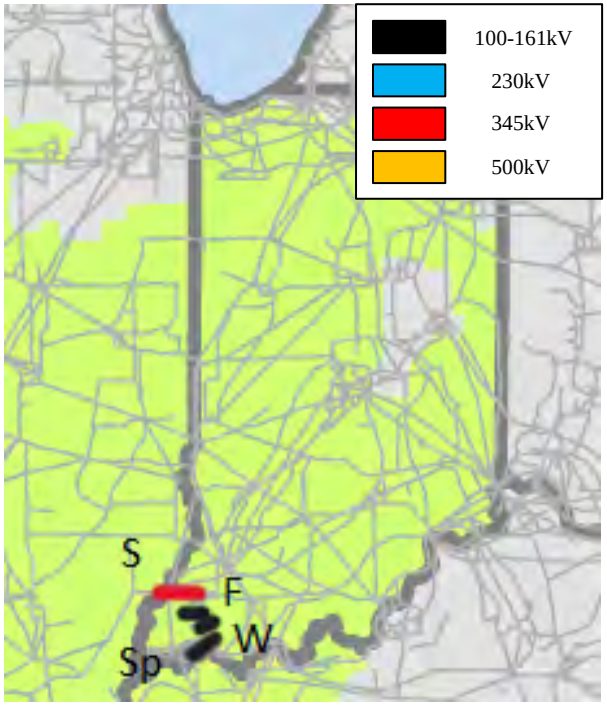
Per language in Section 5.2.2.1 of BPM-011 on Generation Limited Transfer for CIL/CEL:

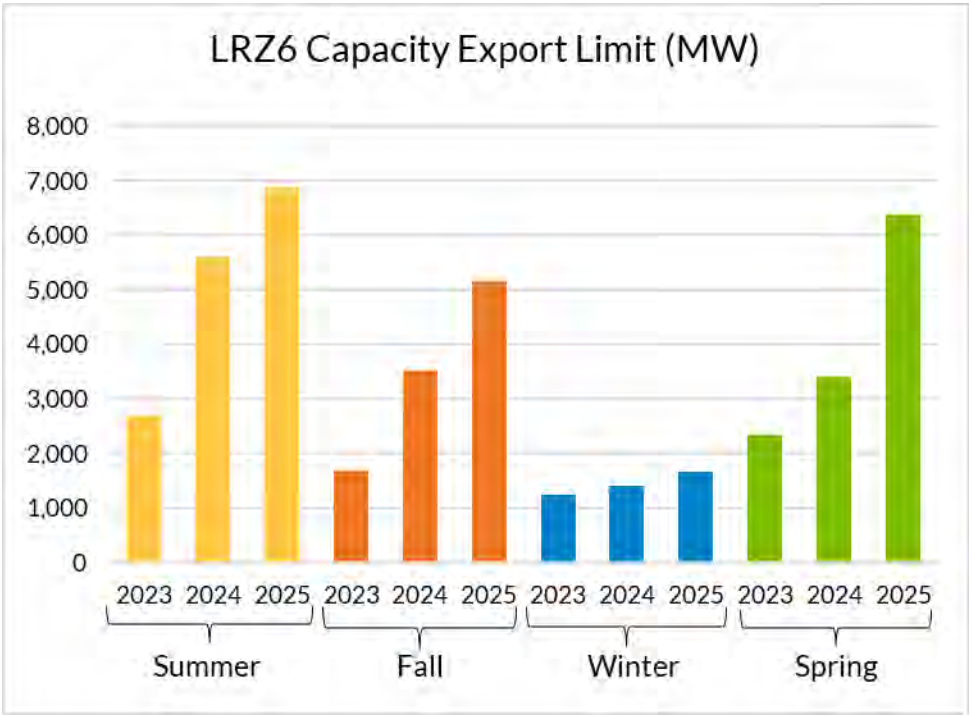
If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report the LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).



Capacity Export Limits
Zone 6: IN and KY

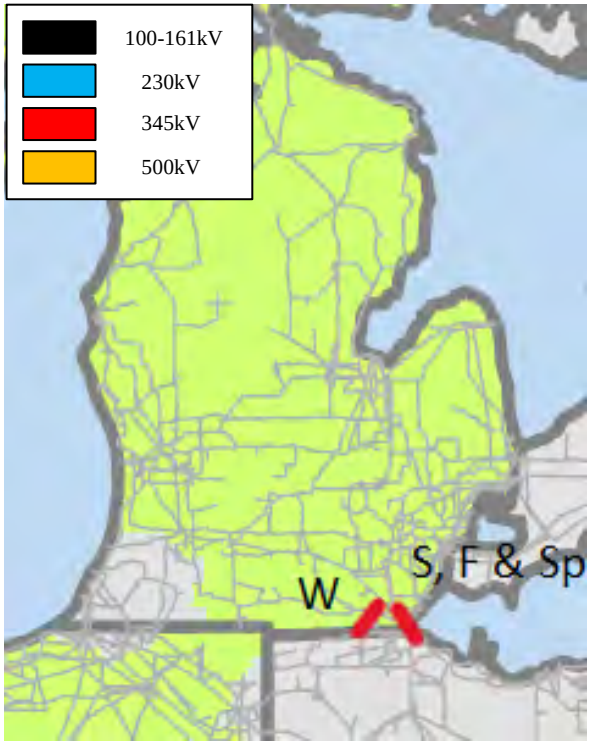
LRZ6	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391

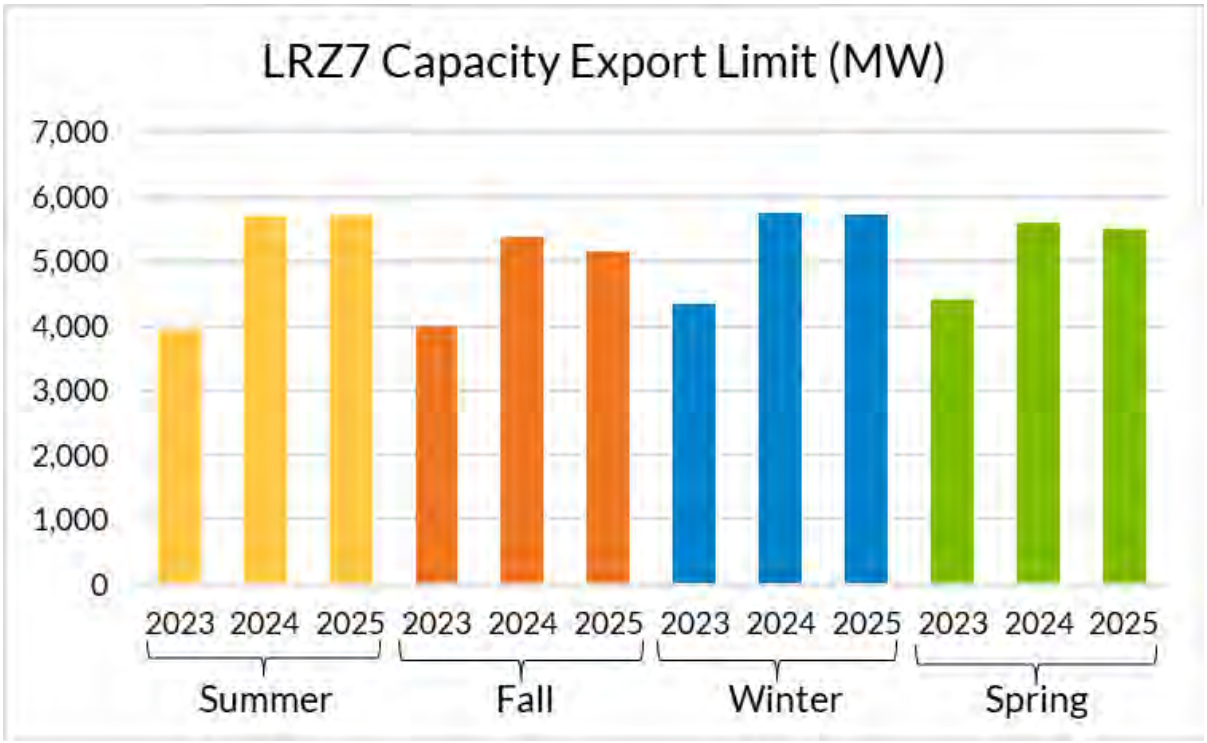




Capacity Export Limits
Zone 7: MI

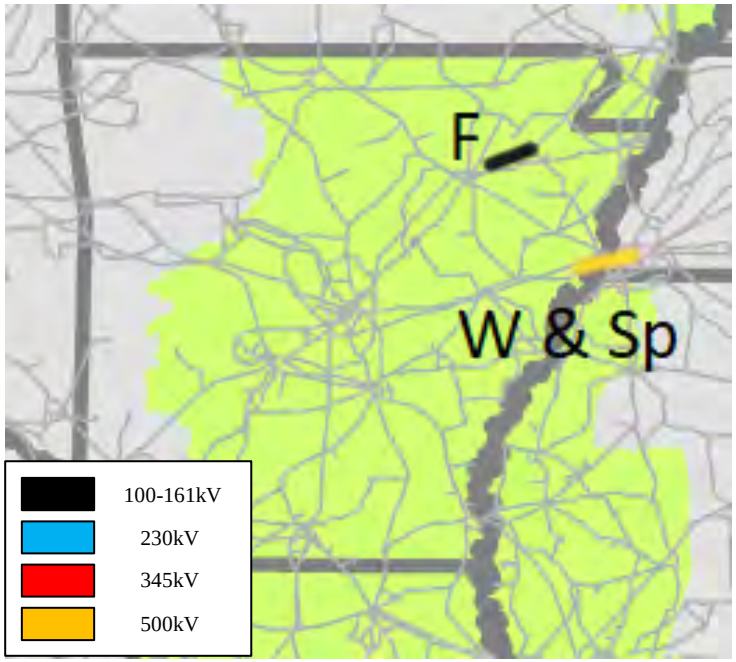
LRZ7	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499

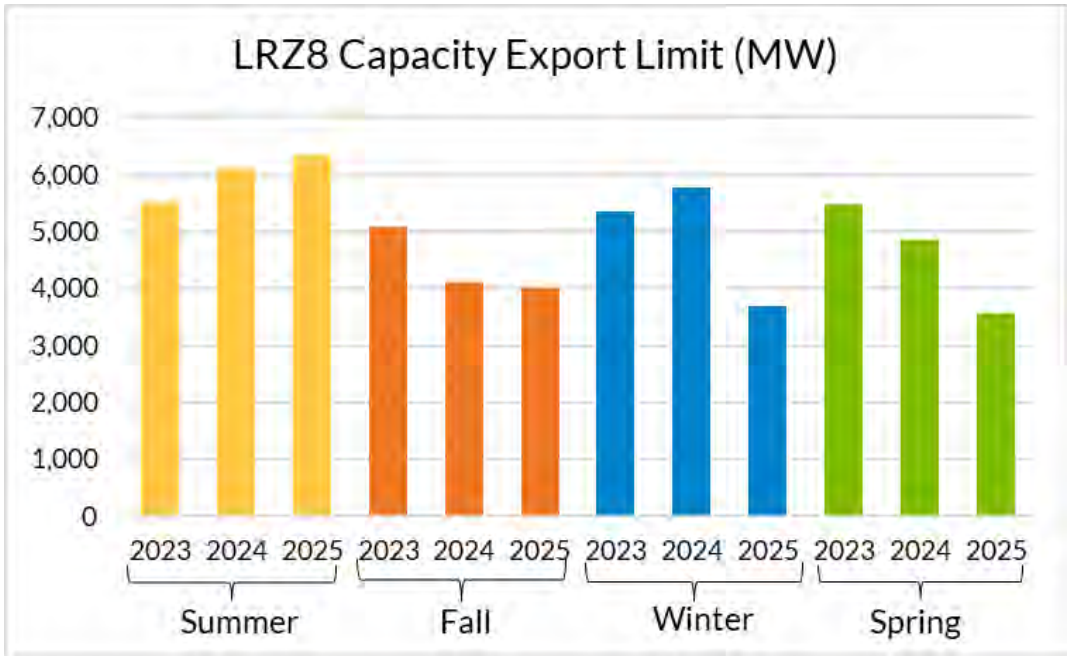




Capacity Export Limits
Zone 8: AR

LRZ8	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559

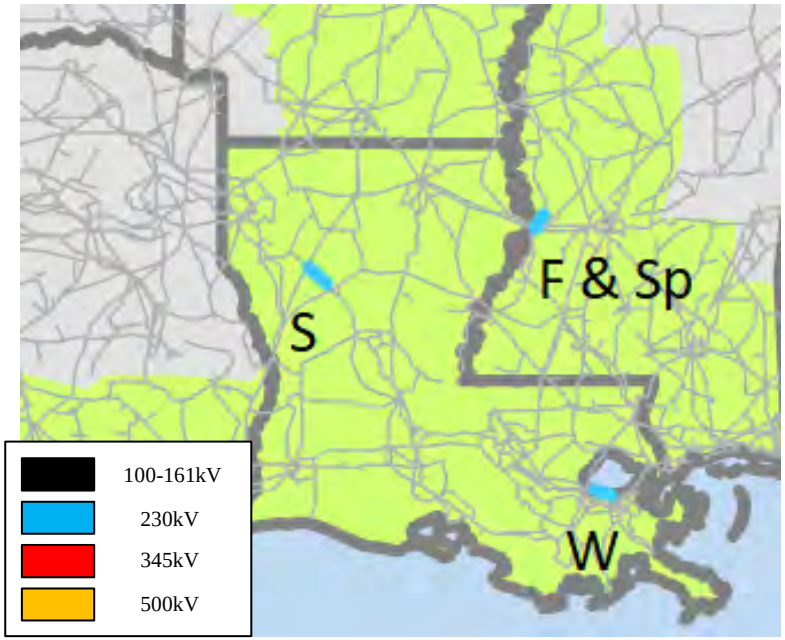


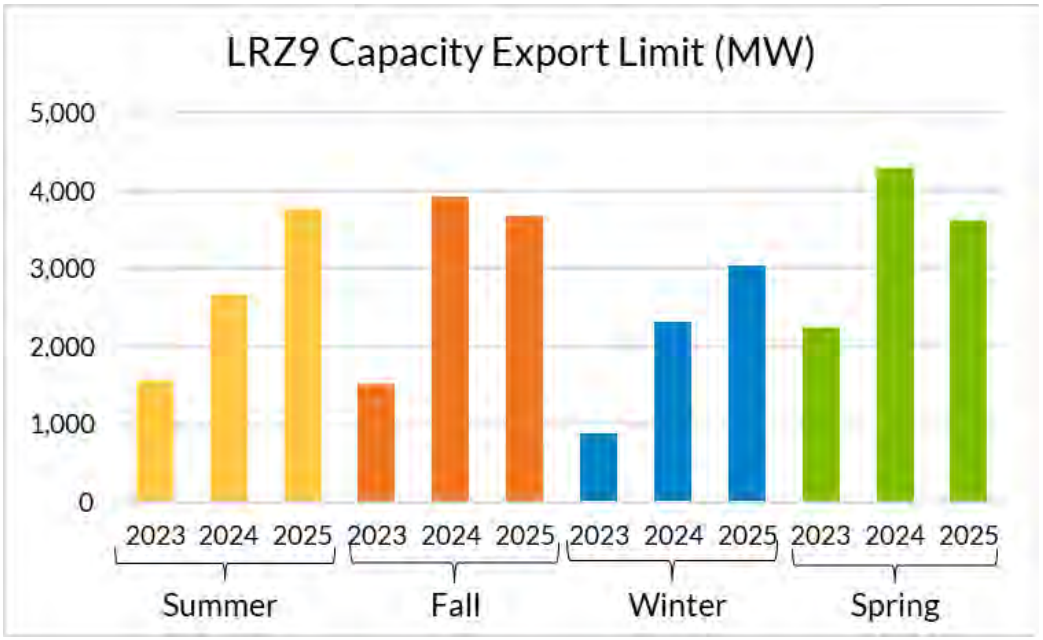


Primary Driver for Winter 2025-2026 & Spring 2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

Capacity Export Limits
Zone 9: LA and TX

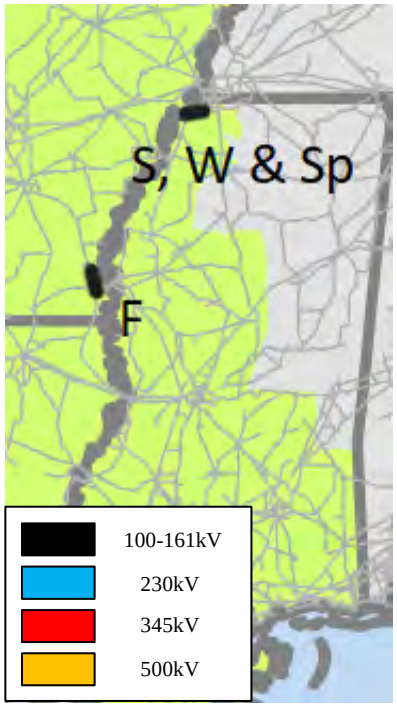
LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631

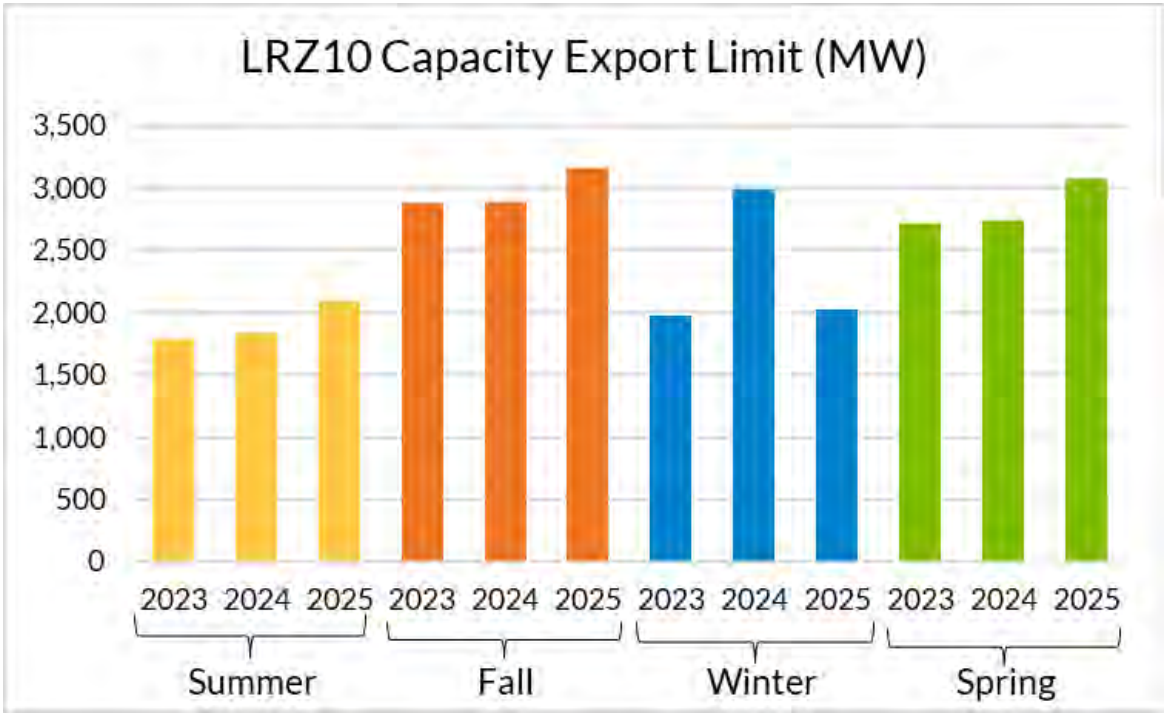




Capacity Export Limits
Zone 10: MS

LRZ10	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072





Primary Driver for Winter 2025-2026: New Resources are causing different flow patterns in the base model, leading to earlier congestion

Next Steps

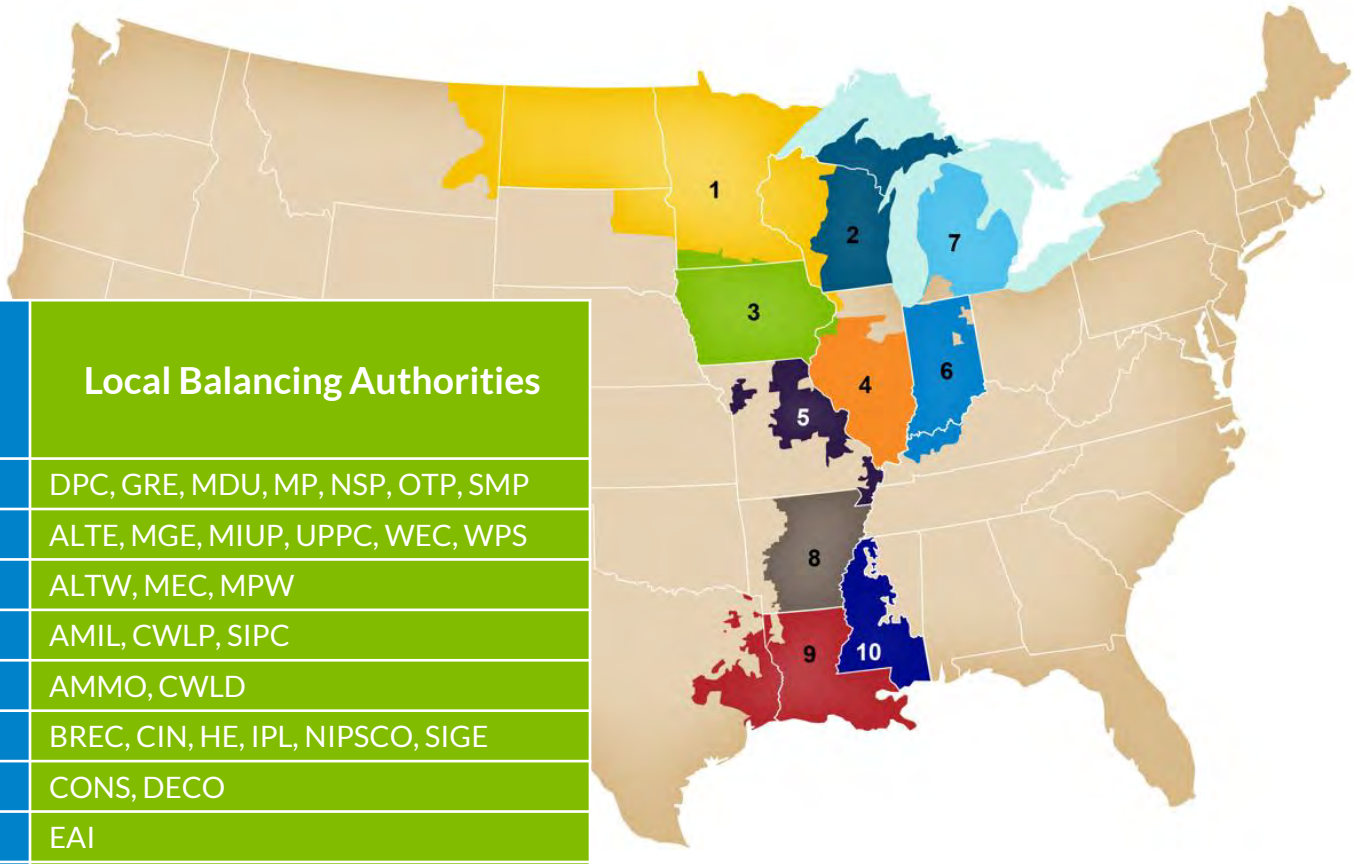
- Planning Year 2025-2026 CIL/CEL values are finalized and will be entered in MECT.
- March 2025 – MISO will receive a final list of Controllable Exports and will adjust CIL/CEL values if necessary.

Contact

jdibasilio@misoenergy.org

MISO Help Center:
https://help.misoenergy.org/

MISO Local Resource Zones



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 38

MISO LOLE Presentation

LOLE 101: Probabilistic Analyses

LOLE 101 Training

5/8/2018

Loss of Load Expectation (LOLE) 101 Sections

- LOLE Background & History
- LOLE Study Connections to other MISO Processes
- Generating Availability Data System (GADS) Overview
- LOLE Modeling
- Strategic Energy Risk Valuation Model (SERVM)
- LOLE Results Walkthrough
- Takeaways
- Reference Materials

Loss of Load Expectation (LOLE) Definition

LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand

Loss of Load Probability (LOLP) is the probability in a given hour	Sum of the Daily Peak LOLP values is an expectation (LOLE)	Sum of all LOLP values is called Loss of Load Hours (LOLH)

LOLE is used to study Generation (Resource) Adequacy

Generally considered to be the existence of sufficient resources, within a system, to satisfy consumer demand. A product of unit availability, "perfect storm". The study of low probability, high impact events.

1-day in 10-years LOLE Criteria

MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:

<1-day in 10-years

=

NERC Standard BAL-502-RF-03

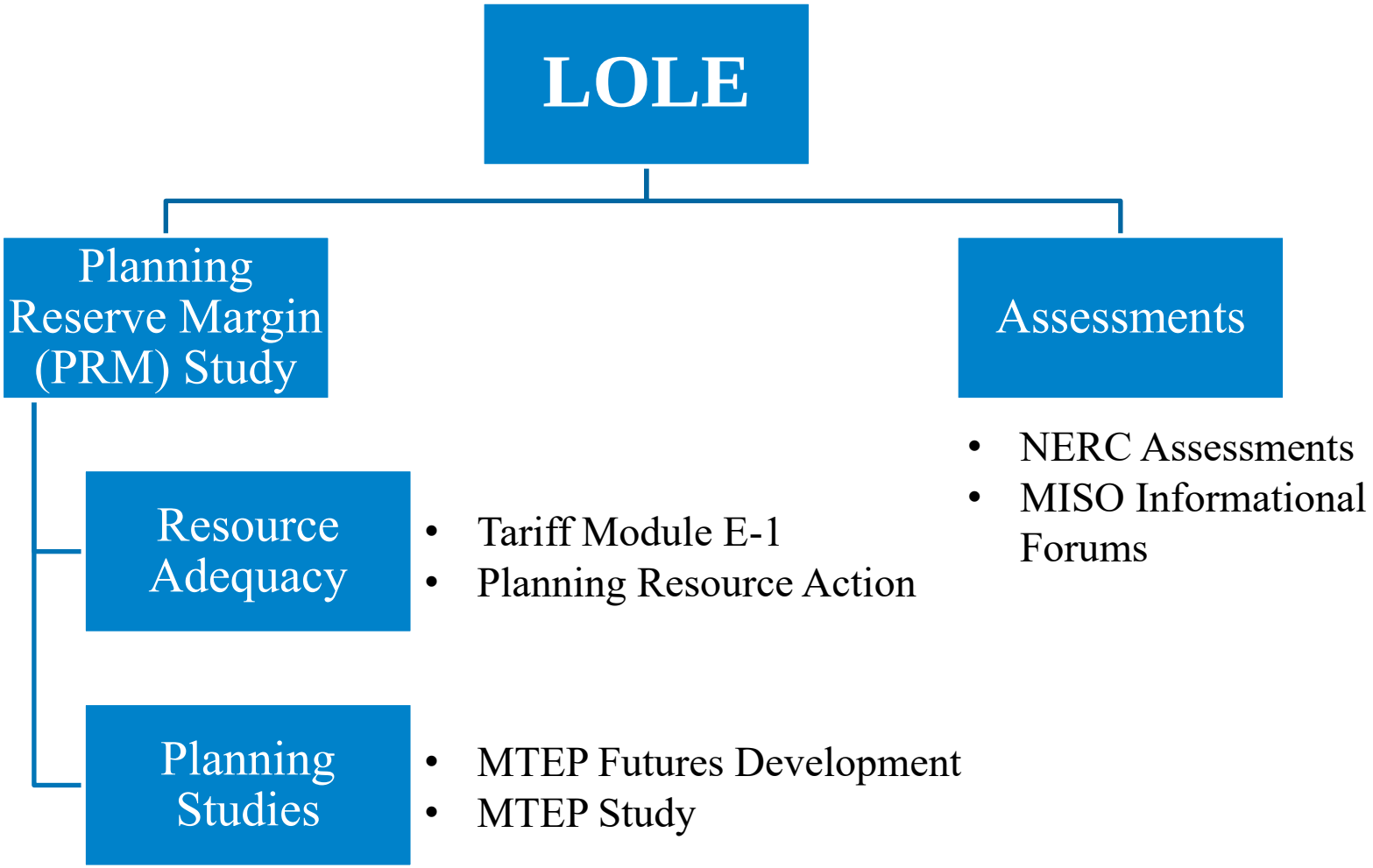
- Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. (This is comparable to a “one day in 10 year” criterion).

Common Terminology Misconceptions

- 1 day in 10 years LOLE ≠ 24 hours in 10 years LOLH
  - Example: 2 hours of firm load shed = 2 loss of load hours and 1 day of loss of load
  - By definition 1 day/ 10 years LOLE ≤ 24 hours / 10 years LOLH

- Cannot calculate Loss of Energy Expectation (LOEE) from LOLH without running complete analysis

LOLE Connections to Various MISO Processes



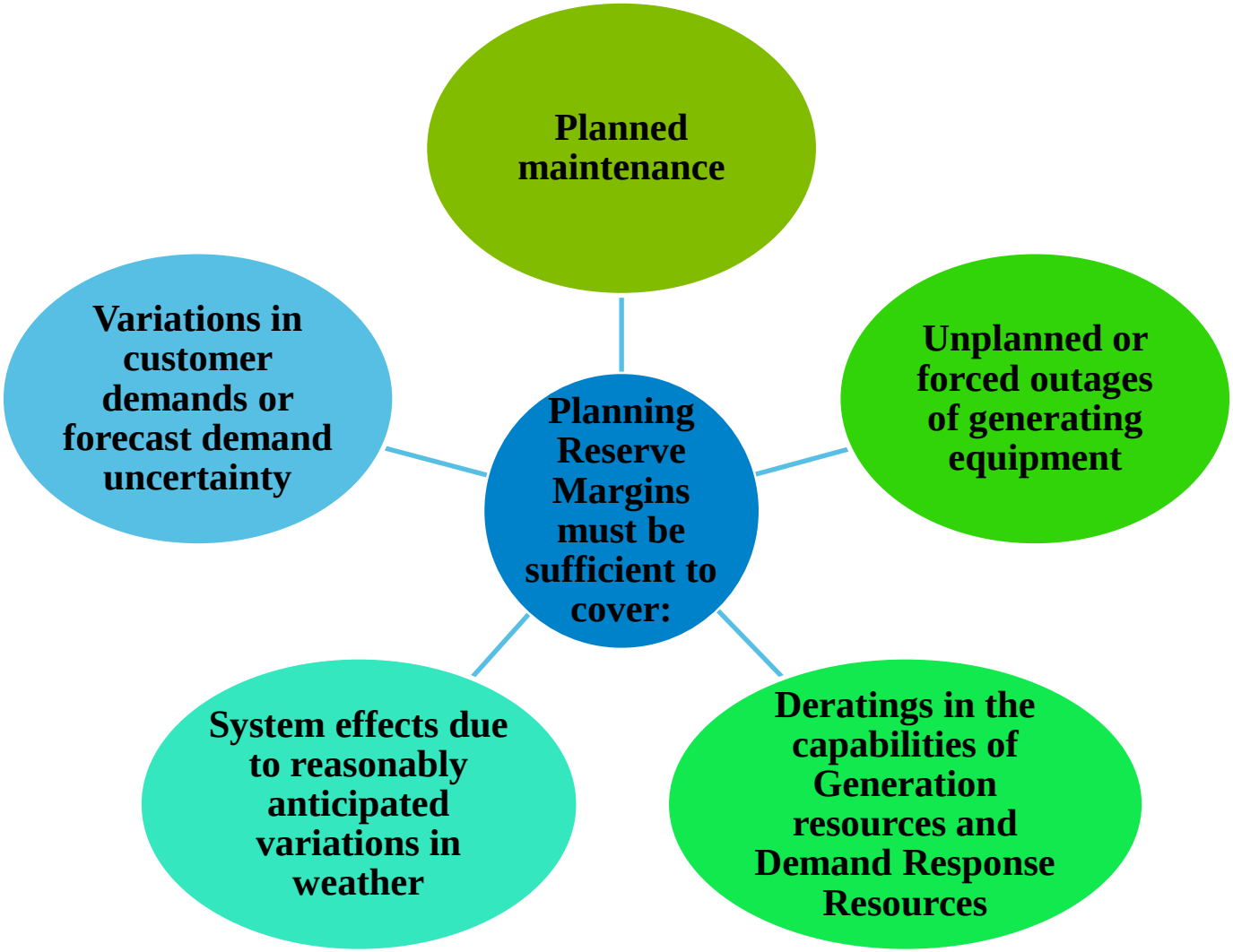
Resource Adequacy Overview

- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin

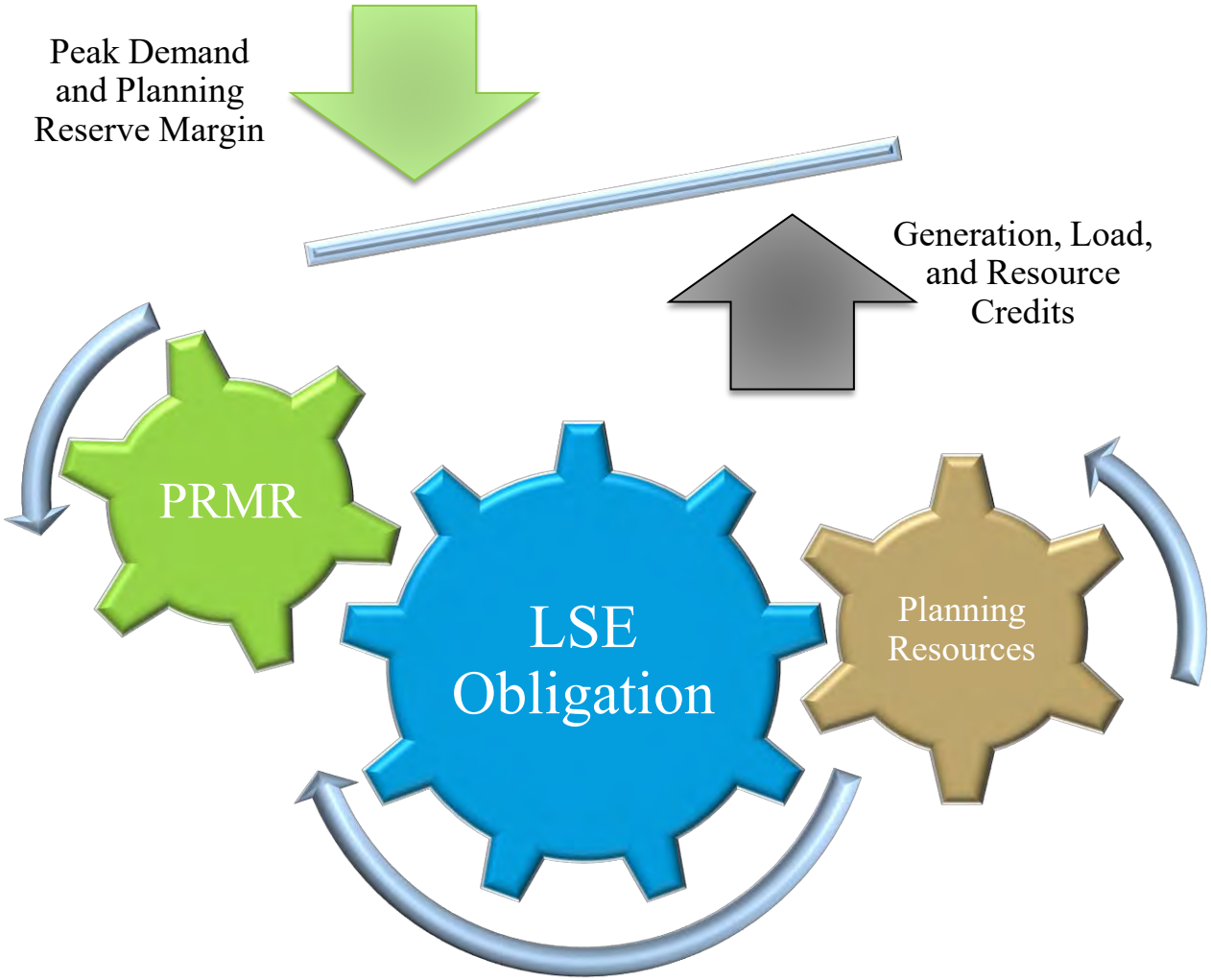
Margins necessary to promote Resource Adequacy need to be assessed on:

Longer-term planning basis	Near-term operational basis
Focus of MISO's RA Construct is on the longer-term planning margins used to provide sufficient resources to reliably serve load on a forward-looking basis	Resources dedicated to meet Demand have an obligation to be available to meet real-time customer demand and contingencies

Planning Reserve Margins (PRMs)



Overview of MISO Resource Adequacy Requirements



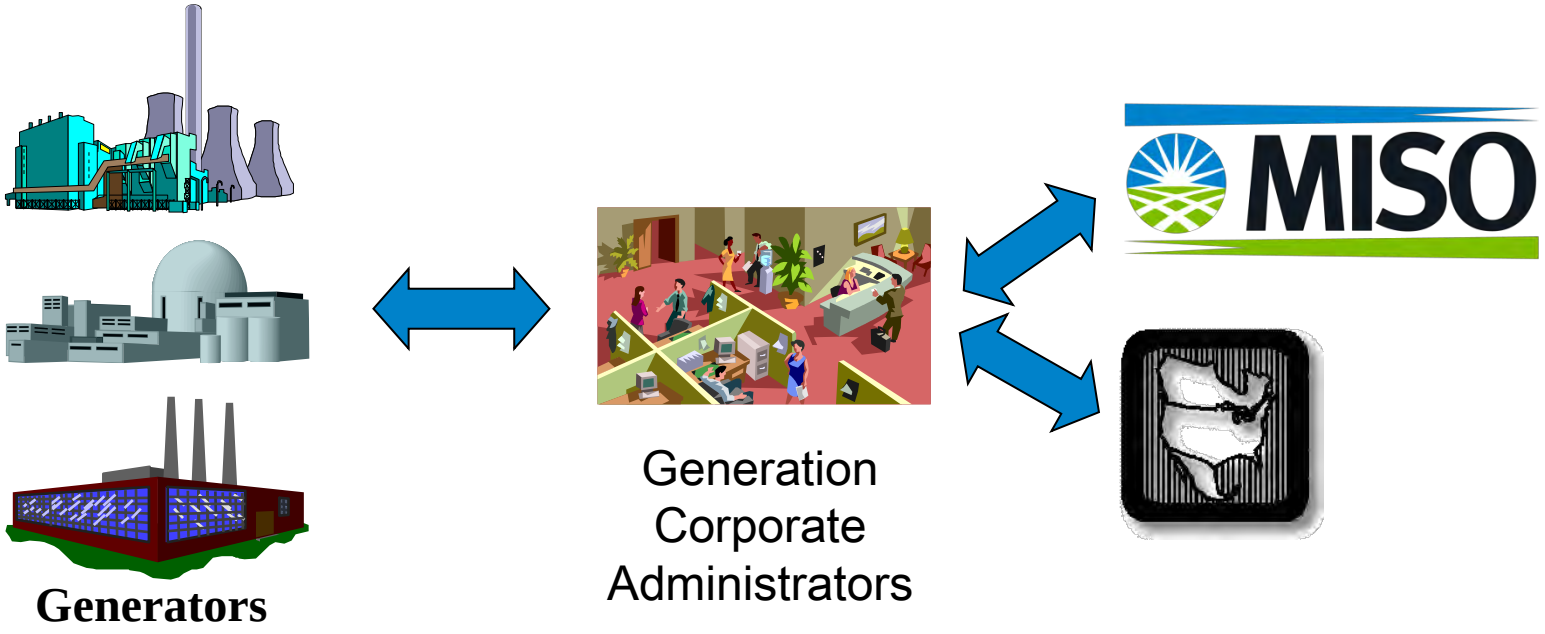
PowerGADS – Performance & Reliability System

For capacity planning and reliability study purposes,

all generating facilities declared as capacity resources in the MISO market

are required to submit GADS event and performance data

to determine the value of the facility as an unforced capacity resource



GADS Data Requirements…

- Generation Resources
- External Resources
- Demand Response Resources backed by behind the meter generation
- or Behind the Meter Generation (BTMG)

Greater than or equal to 10 MW, based on Generation Verification Test Capacity (GVTC)

- Must submit generator availability data (including, but not limited to, NERC GADS) into PowerGADS through the Market Portal

Less than 10 MW, based on (GVTC), that begin reporting generator availability data

- Must continue to report such information

GADS Data Requirements…

- Quarterly Submittal of Data
  - Stakeholders are expected to submit data on a quarterly basis
  - Quarterly GADS data must be received by the last day of the month following the operating quarter
  - Quarterly GADS data must be Level 2 Validated by the last day of the month following the operating quarter

GADS Data Requirements…

- A unit will receive 100% EFORd if it fails to submit GADS data and successfully Level 2 Validate

- Assigning 100% EFORd will impact a unit's unforced capacity calculation
  - $UCAP = GVTC * (1 - EFORd)$

Three Types of Data are to be Collected…

Event Data

- Each time a unit has a change in operating status or capability, an *event* is recorded
- From these event reports a unit's operational history can be reconstructed

Generation Performance Data

- A unit's actual generation, hours of operations, and operational characteristics

Fuel Performance Data (optional)

- A unit's actual fuel consumption and fuel quality data

PowerGADS – Event Data

Event data – to be collected:

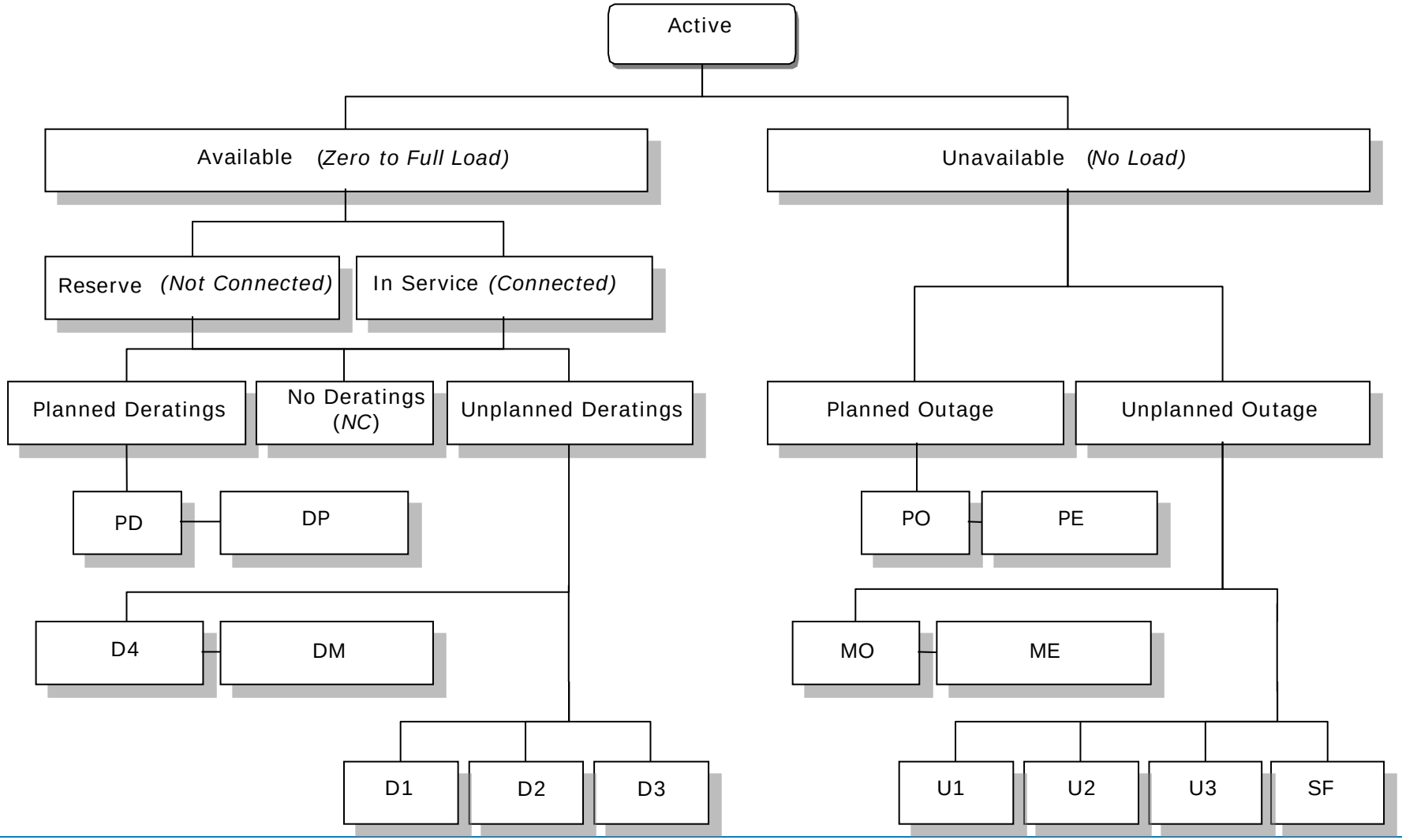
- Event Number
- Event Type
- Start of Event
- End of Event (Can be blank if event is ongoing)
- Net Available Capacity
- Primary Cause Code
- Additional Cause Code (Optional)
- Event Contribution Code
  - describes impact or contribution that this cause or component had on the event
- Verbal Description (Optional)
- Failure Code (Optional)

PowerGADS – Performance Data

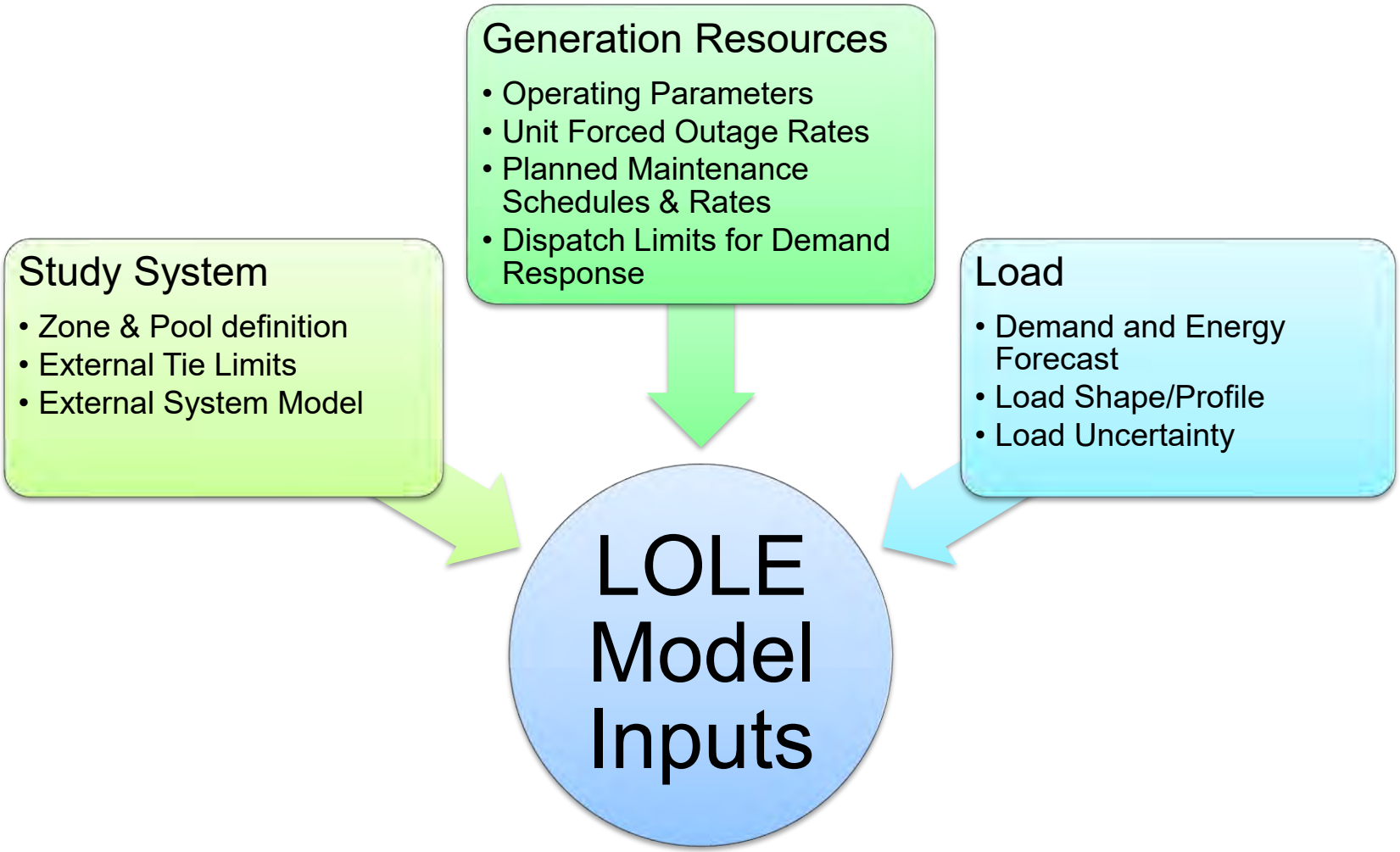
Performance data – to be collected:

- Net Maximum Capacity
- Net Dependable Capacity
- Net Actual Generation
- Typical Unit Loading Code
- Loading Verbal Description
  (If Typical Unit Loading Code is 6)
- Attempted Unit Starts
- Actual Unit Starts
- Unit Service Hours
- Reserve Shutdown Hours
- Pumping Hours
- Synchronous Condensing Hours

PowerGADS – Event Types



LOLE Model Inputs Include:



Source of LOLE Model Input Data

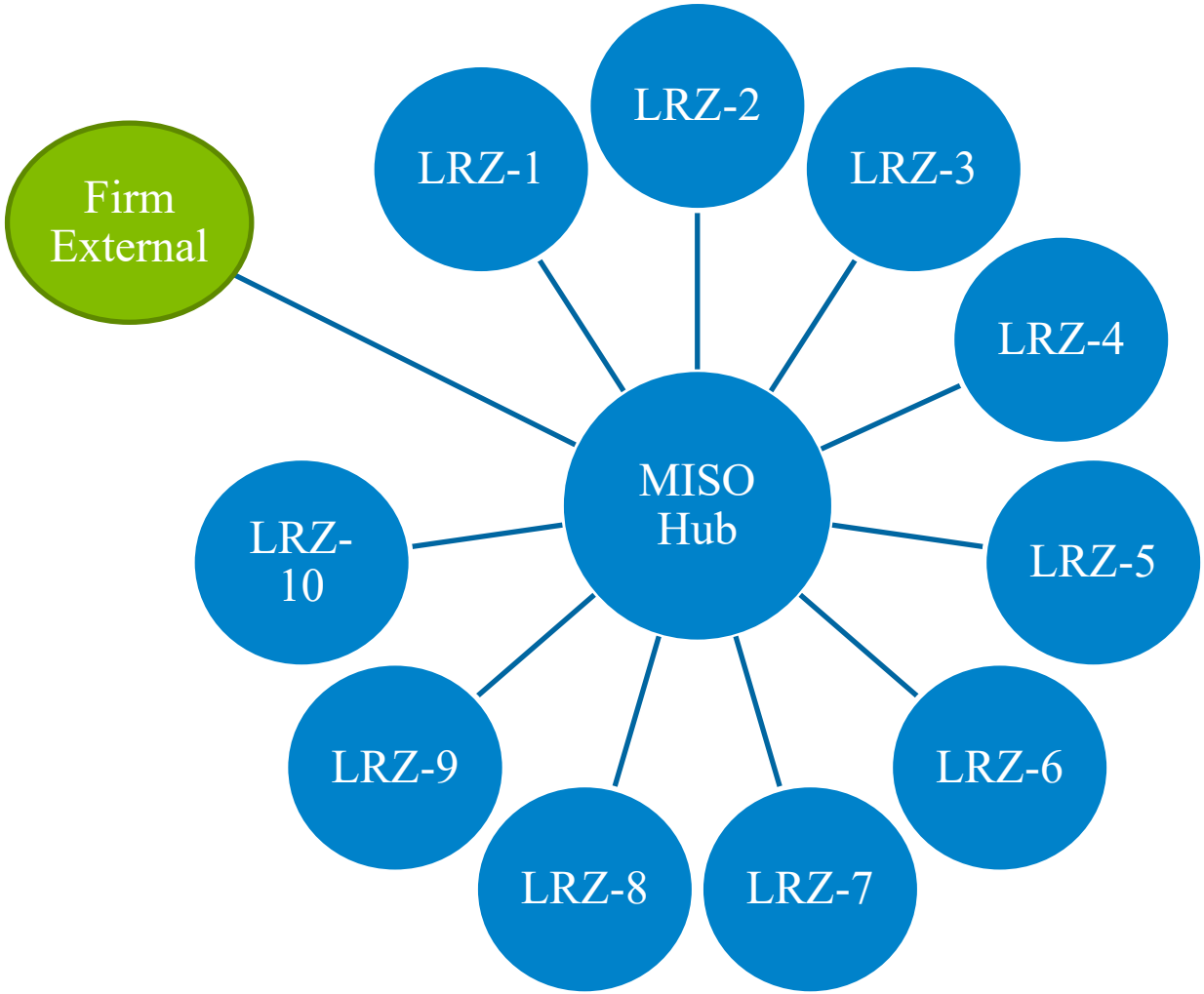
Generation Resources

- Generating Availability Data System (GADS)
  - Unit performance statistics used to calculate forced outage rates
  - Data is uploaded into the MISO system one month after end of each quarter
- Generation Verification Test Capacity (GVTC)
  - Units need to demonstrate maximum output level

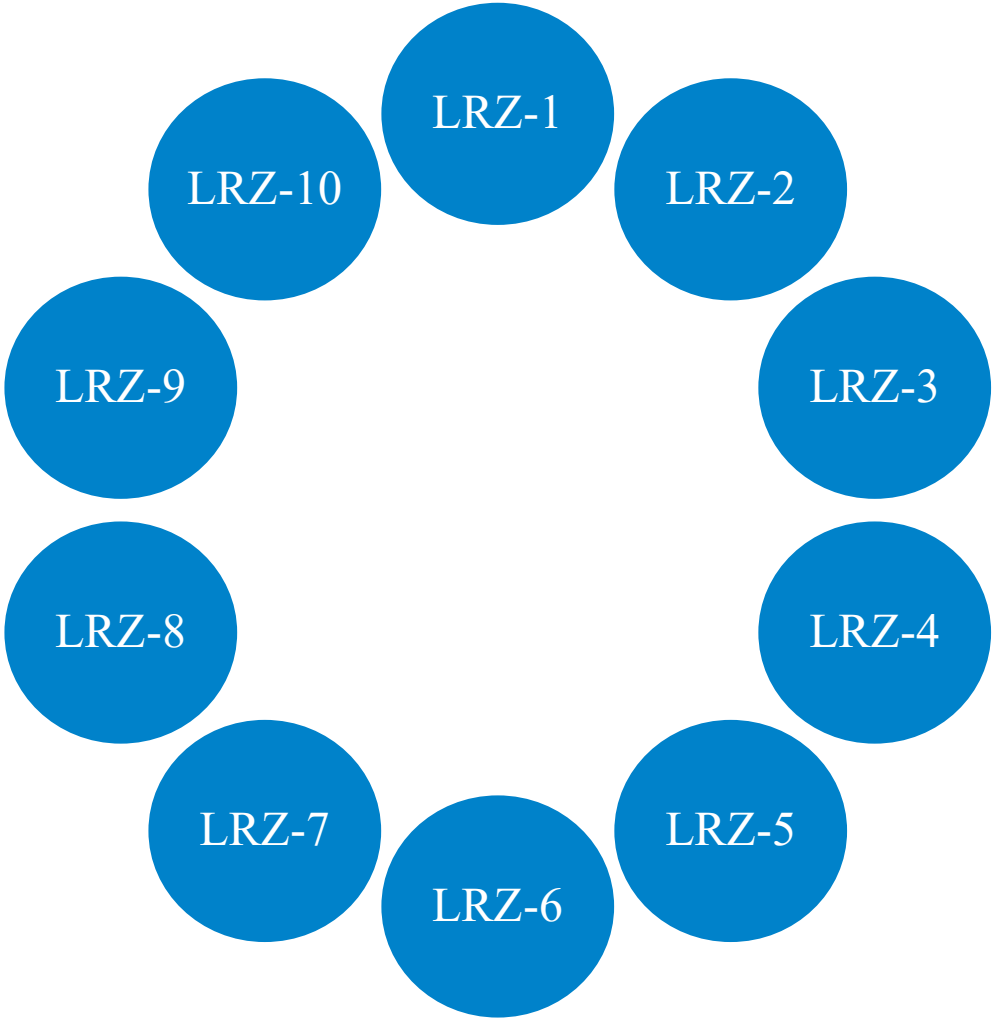
Load

- Load training using historical load and weather data
- Monthly Peak Demand, MISO Coincident Demand and Energy Forecast are uploaded by Load Serving Entities (LSEs) into the Module-E Capacity Tracking (MECT) Tool (deadline Nov. 1st)
- MISO reviews Forecast and Finalize review by March

MISO System LOLE Model



Local Resource Zone LOLE Model



MISO uses the Strategic Energy Risk Valuation Model (SERVM) Software

Managed by Astrapé Consulting

Originated within Southern Company back in the early 1980's

Uses a sequential Monte Carlo simulation

- Steps through time chronologically and randomly drawing unit availability
- Replicating simulation with different sets of random events until statistical convergence is obtained

SERVM resource adequacy metrics consider

- Wide Variation of Load Shapes
- Growth Uncertainty
- Unit Performance

Utilizes a SQL Server database

Analytical vs. Monte Carlo approach to analysis

- Analytical methods work well for small systems and represent a system using mathematical model (A direct mathematical solution)

- Monte Carlo methods simulate the actual process and repeat simulation until convergence criteria is met

- For complex systems, a Monte Carlo “brute force” approach is more appropriate

Types of Monte Carlo Analysis

- Non-Sequential Monte Carlo Simulation
  - Each hour is independent of every other hour
  - Inability to model time-correlated issues
  - Inability to calculate frequency and duration indices
- Sequential Monte Carlo Simulation
  - Steps through time chronologically
  - Ability to model time correlated issues and calculate frequency and duration indices
  - Requires more detailed system data

Utilized SERVM Characteristics

- Multi Area Model
- Multiple Weather Years (supports up to 50 years)
- Detailed DR Representation
- Granular LOLE Calculations

Additional SERVM Characteristics

- Renewable Generation Modeling
- Transportation model to represent multiple neighbors and interconnections
- Full Economic Dispatch of Resources Allowing for Dispatch Constraints on Resources
- Alternative Dispatch During Reliability Events
- Operating Reserves Modeled Based on NERC Guidelines
- Economic Calculations
- Scarcity Pricing Algorithms
- Production Costing Ability

Utilized SERVM Modeling Components

- Weather Years
  - Multiple load shapes
- Economic Load Forecast Error (LFE)
- Unit Outage Modeling
- Energy Limited Resource Modeling
  - Demand Side Options

Additional SERVM Modeling Components

- Weather Years
  - Thermal Capacity/Hydro
- Energy Limited Resource Modeling
  - Hydro and Pump Storage
  - Renewable resources (.i.e. Wind & Solar)
- Scarcity Pricing, Neighbor Modeling, and Transmission Modeling
- Emergency Operating Procedures

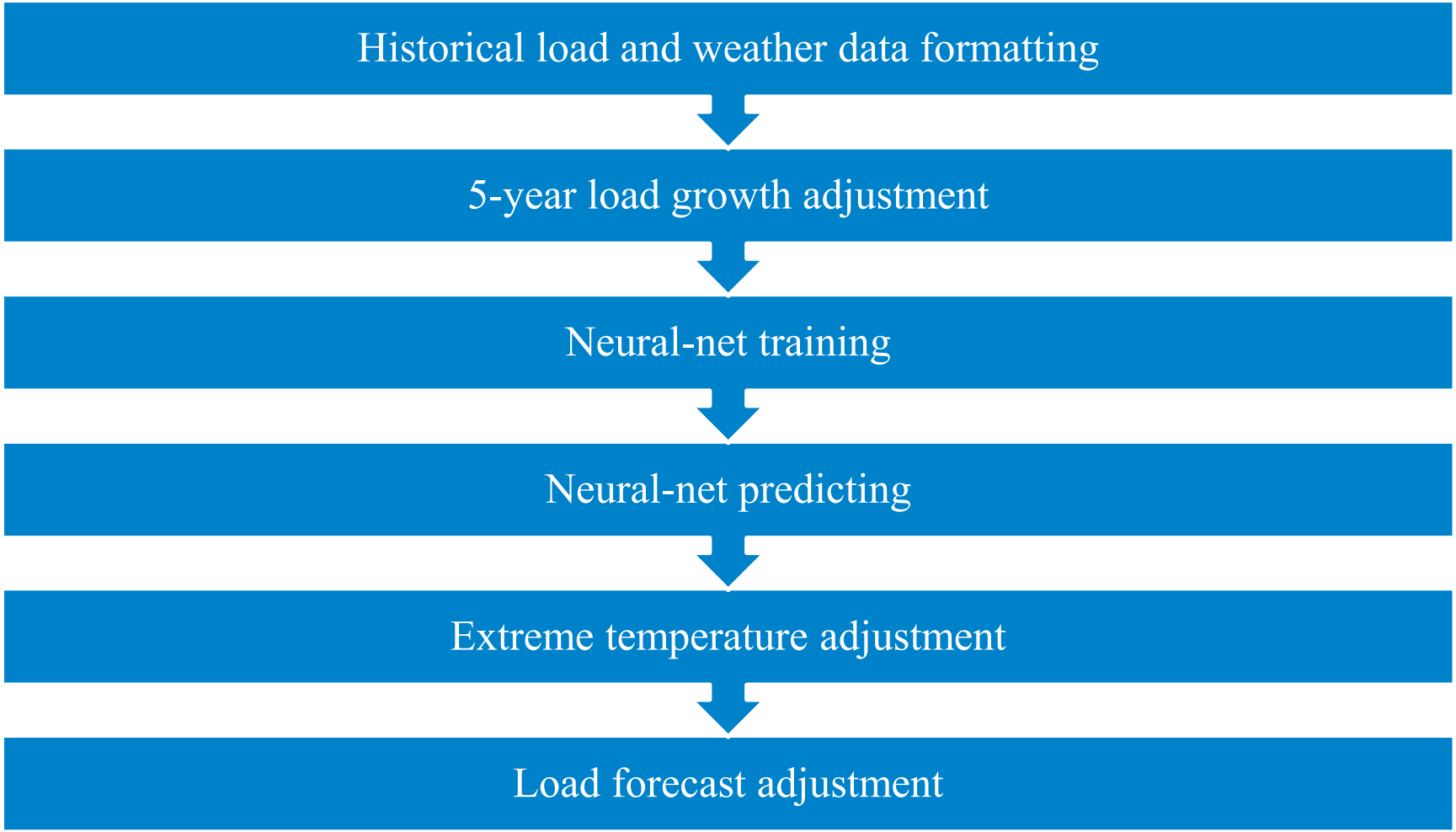
Importance of Load Modeling in LOLE Analysis

- Loss of Load Expectation analysis is largely driven by two factors
  - Generation Uncertainty
  - Load Uncertainty
- Accurately capturing uncertainty is crucial to LOLE analysis
- Load Uncertainty
  - Load Shape
  - Weather Uncertainty
  - Economic Uncertainty

Load Modeling Framework

- Use historic weather years to capture load uncertainty
  - Variance in peak demand
  - Variance in load shape
- Results in more diverse and comprehensive load modeling
  - More accurate shoulder and non-peak load variance and uncertainty
- Utilize Neural-Net software to “train” data

Load Training Process

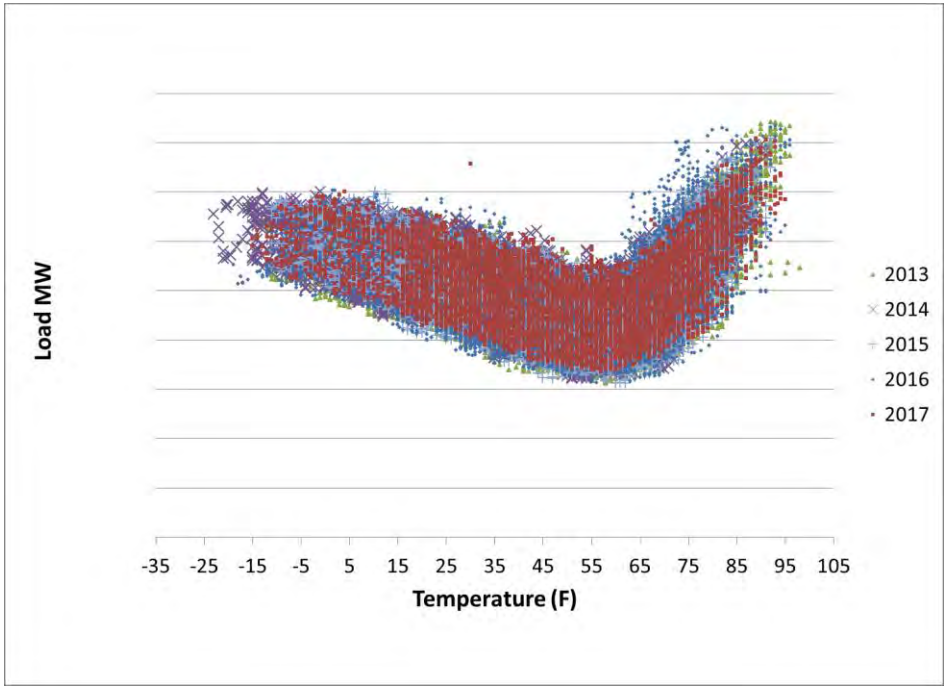


Data Sources for Load Training

- Historical real-time settlement load data
  - Source: MISO
  - 2013 to 2017
- Historical real-time LMR performance
  - Source: MISO
  - Voluntary and MISO deployments
  - 2015-2017
- Historical weather data
  - Source: NOAA
  - 1989 to 2017
- LSE load forecasts
  - Source: LSE submittals to MECT

Historical Load and Weather Formatting

- 5 years of hourly load and temperature (2013-2017)
- Weather data (2013-2017)
  - Month
  - Temperature
  - Time of Day
  - Day of Week
  - 24 hour ago Temperature
  - 48 hour ago Temperature
- Holidays are set to Sunday
  - New Year's Day
  - Memorial Day
  - Independence Day
  - Labor Day, Thanksgiving Day & Christmas Day



5-Year Load Growth Adjustment

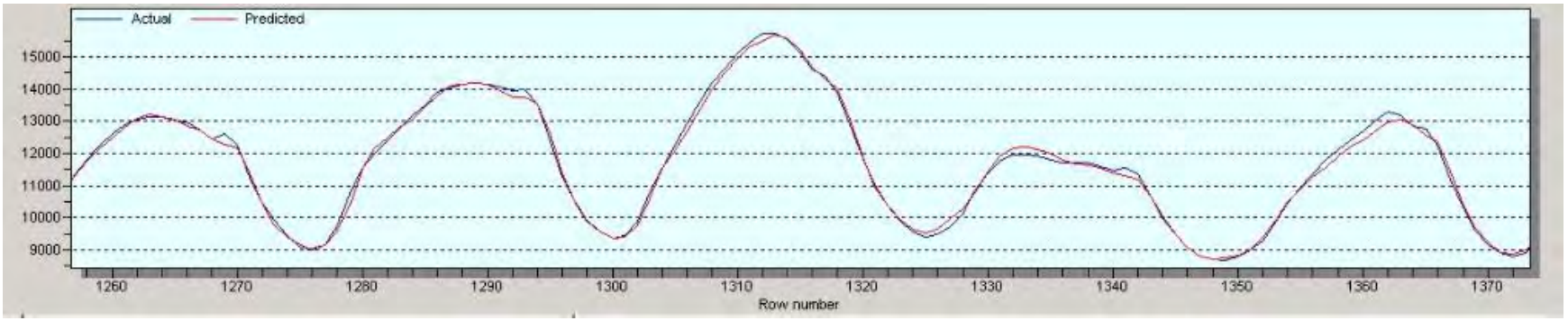
- 5 years of load data should not include load growth due to economics
- Load normalized to consistent economics
- Adjustment calculated based off high temperature load analysis i.e. 90 degrees and above

NeuroShell Predictor Software

- Ward Systems Group Software
- Used for pattern recognition of multi-variable problems
- Makes predictions based off of established neural-net functional relationships
- Software tutorial can be found at the link below:
  - http://www.wardsystems.com/predictortutorial.asp
- Load Training Input Variables:
  - Month
  - Day of week
  - Time of day
  - Previous hour load
  - Temperature
  - 24 hour ago temperature
  - 48 hour ago temperature
- Load Training Output Variables:
  - Actual Load

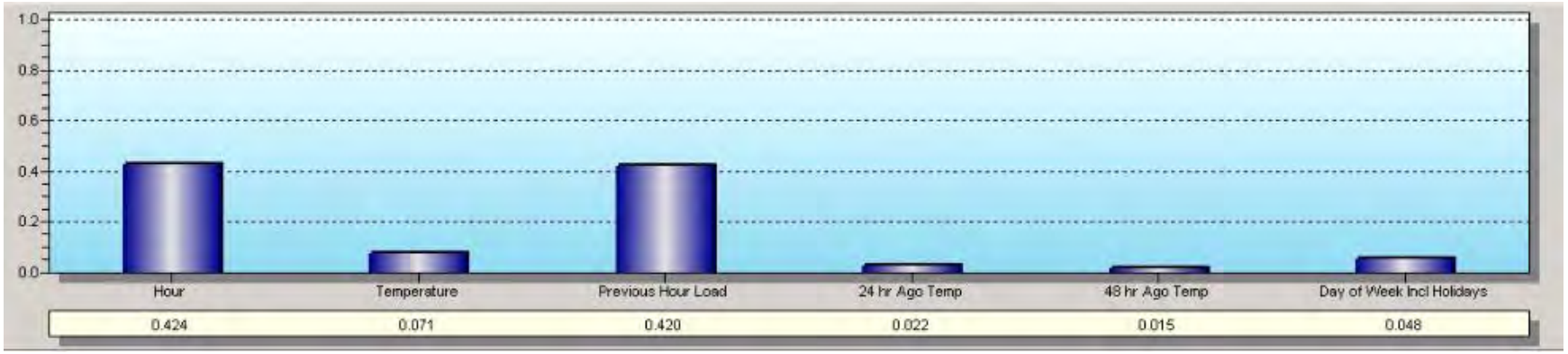
	Hour	Temperature	Previous Hour Load	24 hr Ago Temp	48 hr Ago Temp	Day of Week Incl Holidays	Actual Load
1	0	84	12984.172	78.5	82	1	12052.491
2	1	83	12052.491	70	80	1	11406.383
3	2	83	11406.383	69	76	1	10984.624
4	3	82	10984.624	69	75	1	10747.635
5	4	82	10747.635	72	75	1	10849.012
6	5	81	10849.012	73	74	1	11433.276
7	6	79	11433.276	74	74	1	12365.329
8	7	79	12365.329	74	74	1	13136.045
9	8	78	13136.045	76	75	1	13864.401
10	9	79	13864.401	78	77	1	14259.09
11	10	79	14259.09	82	80	1	14576.561
12	11	78	14576.561	83.5	82	1	14729.459
13	12	79	14729.459	85	84	1	14715.28
14	13	79	14715.28	84	86	1	14659.616
15	14	79	14659.616	87.33333333	87	1	14398.177
16	15	77.75	14398.177	88.5	88	1	14239.96
17	16	73	14239.96	90.5	89	1	14212.895
18	17	73.33333333	14212.895	92	89	1	14188.923
19	18	77.66666667	14188.923	92	90	1	14075.644
20	19	78	14075.644	92	90	1	13852.38
21	20	78	13852.38	90	89	1	13712.71
22	21	80	13712.71	90	87	1	13681.636
23	22	78	13681.636	88	86	1	12928.871
24	23	78	12928.871	87	85	1	12130.917
25	0	77	12130.917	84	78.5	2	11450.251
26	1	78	11450.251	83	70	2	10956.724
27	2	79	10956.724	83	69	2	10612.272

Neural-Net Training



Best net statistics

R-squared	0.996521
Avg.error	91.26518
Correlation	0.99829
MSE	13960.78
RMSE	118.1557
% in range	0.0%
% same sign	100.0%

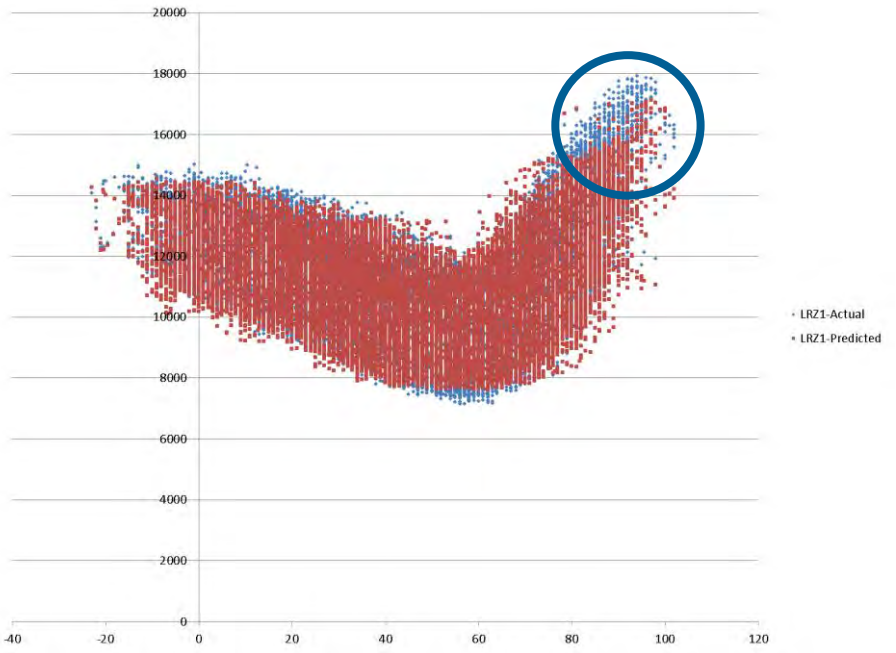


Neural-Net Predicting

- 30 years of historical weather
  - 1989 to 2017
- Neural-Net applied to 30 years of historical weather to predict load
- Output is 30 weather year load shapes at 5 year normalized economy
  - i.e. Predicted 2018 load with1999 weather

Extreme Temperature Verification

- Verify load training at extreme temperatures is accurate
- Less data points at temperature extremes for neural-net training



Load Forecast Adjustment

- Average of 30 predicted load shapes adjusted to match LRZ's 50/50 zonal peak load forecast for study year
- Ratio of 1st years Non-Coincident Peak Forecast to Zonal Coincident Peak Forecast applied to future years Non-Coincident Peak Forecast
- Results in 30 Planning Year weather load shapes
  - i.e. 2019-20 PY load if we have 1995 weather

Economic Load Forecast Error

- Use Projected and Actual GDP Growth Rates for Economic Uncertainty
  - Use Congressional Budget Office (CBO) projections for GDP growth (historic)
  - Compare with the actual GDP growth taken from the Bureau of Economic Analysis
  - Translate the GDP forecast error into electric utility forecast error by multiplying by a scalar
    - Rate at which electric load grows in comparison to GDP
  - Calculate the standard deviation of forecast error
  - Using the standard deviation, create a normal distribution of forecast error

Economic Load Uncertainty

- The 2018/19 PY LOLE study showed that the economic load uncertainty modeling resulted in a 0.2 percentage point increase to the MISO Planning Reserve Margin

	Load Forecast Error (LFE) Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability to assigned to each LFE				
1.19%	10.4%	23.3%	32.6%	23.3%	10.4%

Advantages in Load Modeling with historical weather

- Multiple load shapes based on weather more accurately capture
  - Variance in load shapes
  - Variance in peak load
  - Seasonal load uncertainty
  - Frequency and duration of severe weather patterns
- Decouple weather and economic uncertainty

Unit Data

- Unit Name
- Unit Physical Local Resource Zone (LRZ)
- Installation Date
- Retirement Date
- Type (Thermal, Curtailable Load, Renewable)
- Unit Summary Type
  - Thermal (Nuclear, Fossil Steam, Combustion Turbine, Hydro, Pumped Storage Hydro)
  - Curtailable Load (Demand Response)
  - Renewable (Intermittent Resources such as Wind, Run-of-River Hydro, Biomass and Energy Efficiency)
- Thermal Units
  - Utilize the GVTC for a peak capacity and each unit's monthly Net Dependable Capacity (NDC) submitted in PowerGADS determines each unit's monthly capacity profile

Forced Outage Rates & Unit Maintenance – Thermal Units Only

- Forced Outage Rates
  - Time to Repair
  - Time to Failure
- Fixed Maintenance – Typically Nuclear Units
  - Begin Date
  - Stop Date
- Planned Outage Rates
  - Percentage of the year in which a unit will be on scheduled maintenance
  - Planned Outage Factor + Maintenance Outage Factor from PowerGADS
- Maintenance scheduled on days with maximum reserves

Curtailable Load Units (Energy Limited)

- SERVM dispatches Demand Response (DR) based on several constraints
  - Days per week
  - Hours per day
  - Hours per year
  - Dispatch price
- Use limitations to model fatigue
  - Minimum Megawatt (MW) – Zero
  - Maximum Megawatt (MW) – Monthly Profile

Demand Side Management (DSM)

- Renewable Units
- Net Hourly Load Modification
  - Maximum Megawatt (MW) – Monthly Profile
  - Positive values decrease load

Non-Firm Support

- Represents benefit of being part of Eastern Interconnect
- 1 MW of non-firm support reduces requirement by 1 MW
- Reliability targets highly sensitive to fluctuations in non-firm support
- LOLE study uses set MW amount of non-firm

Firm Imports

- External resources FRAP'ed or Offered in MECT are included in LOLE modeling
- External purchases are modeled similar to MISO units
- Modeled from external region to MISO
- Firm imports are only modeled in MISO PRM model and not zonal LRR model
- External firm imports impact LOLE based on unit characteristics

Firm Exports/Sales

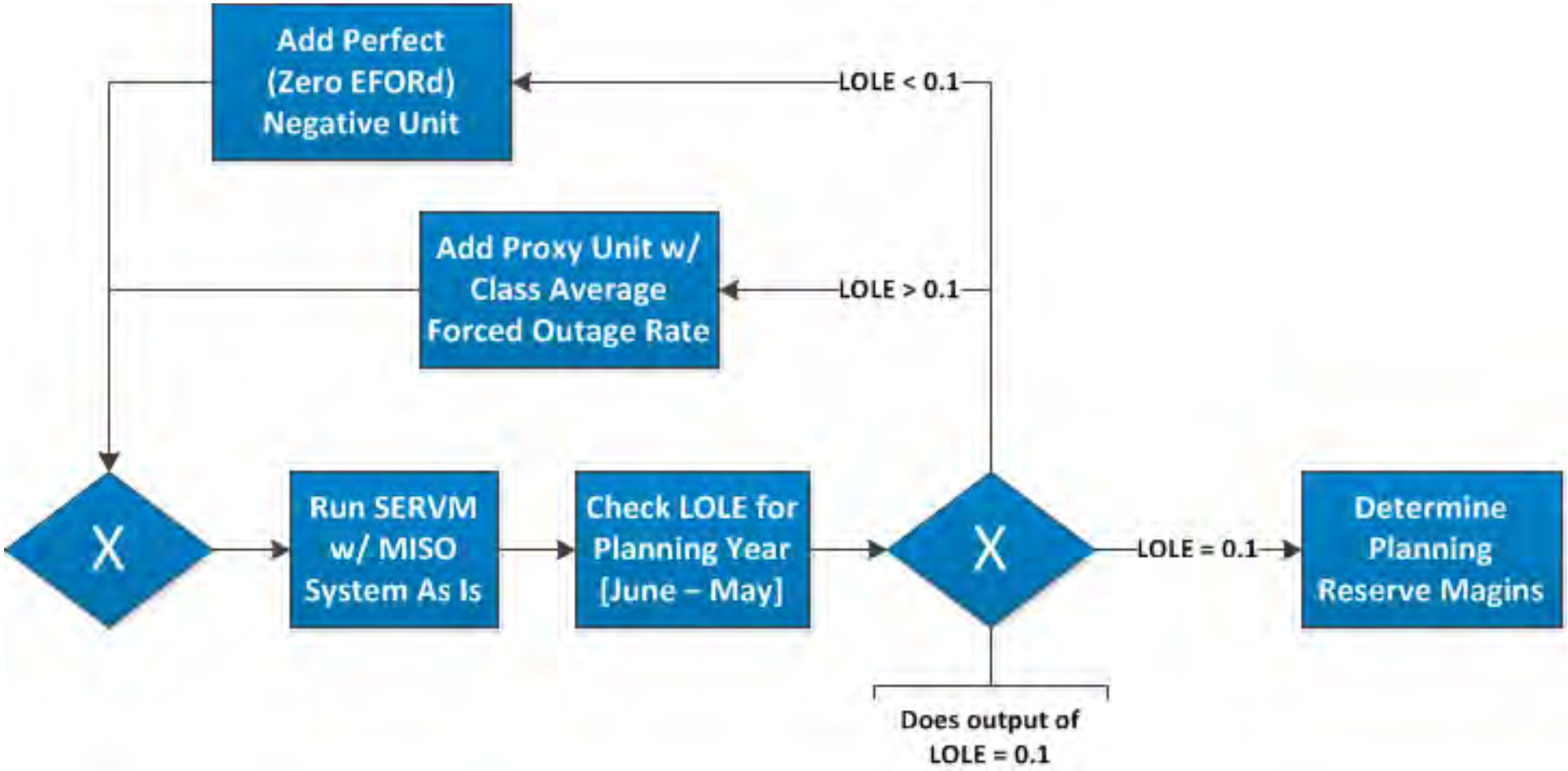
- Capacity that is ineligible for MISO PRA is excluded from MISO and zonal models
- Only units that have capacity obligations outside of MISO are designated as sold in the LOLE model
- External firm exports impact LOLE based on unit characteristics

SERVM Simulation Frameworks

30 Weather Years (equal probability)	x	5 Economic Uncertainties (Normal Distribution)	=	150 Load Scenarios
150 Load Scenarios	x	300 unit outage draws	=	45,000 8760 hour simulations

** Scenarios are an example of framework and are not fixed

Capacity Adjustment Flowchart



LOLE Study Deliverables to MISO's Planning Resource Action (PRA)

- The LOLE study has four deliverables to the Planning Resource Auction
  - MISO PRM UCAP [%]
  - Local Resource Zones (LRZ) Local Reliability Requirement (LRR) per unit
  - LRZ Capacity Import Limit (CIL)
  - LRZ Capacity Export Limit (CEL)
- LOLE deliverables are applied to updated demand forecasts to calculate PRA requirements

Calculation of MISO PRM [%]

MISO Planning Reserve Margin (PRM)	2018/2019 PY	Formula Key
MISO System Peak Demand (MW)	125,805	[A]
Installed Capacity (ICAP) (MW)	149,901	[B]
Unforced Capacity (UCAP) (MW)	138,505	[C]
Firm External Support ICAP (MW)	4,938	[D]
Firm External Support UCAP (MW)	4,764	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-4,550	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-4,550	[G]
ICAP PRM Requirement (PRMR) (MW)	150,289	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,719	[I] = [C]+[E]+[G]
MISO PRM ICAP	19.5%	[J]=[H]-[A]/[A]
MISO PRM UCAP	10.3%	[K]=[I]-[A]/[A]
Post-Processing accounting for non-firm external support		
External Non-Firm Support ICAP (MW)	2,987	[L]
External Non-Firm Support UCAP (MW)	2,331	[M]
With External Support ICAP PRM Requirement (MW)	147,302	[N]=[B]+[D]+[F]-[L]
With External Support UCAP PRM Requirement (MW)	136,388	[O]=[C]+[E]+[G]-[M]
With External Support MISO PRM ICAP	17.1%	[P]=([N]-[A])/[A]
With External Support MISO PRM UCAP	8.4%	[Q]=([O]-[A])/[A]

*MISO Capacity Market procures on UCAP

Calculation of Zonal Requirements and Example PRA Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2018-2019 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	19,055	15,863	11,145	10,638	8,665	19,458	23,225	11,594	23,514	6,756	[A]
Unforced Capacity (UCAP) (MW)	18,095	14,892	10,613	9,481	7,751	18,165	21,196	10,991	21,674	5,657	[B]
Adjustment to UCAP {1d in 10yr} (MW)	2,326	352	202	2,326	2,411	1,782	3,349	-760	1,595	1,581	[C]
Local Reliability Requirement (LRR) UCAP (MW)	20,422	15,244	10,815	11,807	10,162	19,948	24,545	10,231	23,269	7,237	[D]=[B]+[C]
Peak Demand (MW)	17,789	12,858	9,391	9,709	8,199	17,443	21,296	8,072	20,649	4,859	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.8%**	**118.6%**	**115.2%**	**121.6%**	**123.9%**	**114.4%**	**115.3%**	**126.7%**	**112.7%**	**148.9%**	[F]=[D]/[E]

Important LOLE Fundamentals Takeaways

- LOLE is the measure of how long, on average, the available generation capacity is likely to fall short of the load demand
  - LOLE is used to study Generation(Resource) Adequacy
  - Probabilistic analysis accurately captures uncertainty risk
- MISO Resource Adequacy criteria for Planning Reserve target is the industry standard LOLE objective:
  - 1-day in 10-years
  - Aligns with NERC standards
- Achieving reliability in the bulk electric systems requires that the amount of resources exceeds customer demand by an adequate margin (Planning Reserve Margin)
  - LOLE models utilize an Equivalized Transportation Model to determine Planning Reserve Margin and Local Reliability Requirements
- All Market Participants are encouraged to participate in the stakeholder process through LOLEWG

Reference Materials

- Past LOLE 101 Documents
  - LOLE 101 (Apil 11th, 2017)
- Loss of Load Expectation Reports
  - 2018 Loss of Load Expectation (LOLE) Study Report
  - Loss of Load Expectation Working Group (LOLEWG)
  - 2018 Wind Capacity Report
  - Resource Adequacy Documents
- Resource Adequacy Documents
  - BPM
    - BPM 011 - Resource Adequacy
  - MISO Tariff: Module E-1
  - NERC Standard BAL-502-RF-03

Appendix

LOLE Terms and Definitions

- **Installed Capacity:** The installed capacity that is physically located within the zone. The ICAP is the output that the generator tested for its max summer output.
- **Unforced Capacity:** The installed capacity less forced outage rates. Capacity Resources are quantified by applying forced outage rates to installed capacity values (ICAP) to calculate the Unforced Capacity value (UCAP) for the resource.
- **Adjustment to UCAP:** The UCAP capacity adjustment within the zone to drive the zone to the "1 day in 10" criteria if the zone was an island. If a zone is more reliable than "1 day in 10" capacity needs to be removed in order to drive the model to the LOLE metric.
- **LRR (UCAP):** Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Peak Demand**: The zone's annual peak demand including transmission losses.
- **Time of Peak Demand (ESTHE):** The date and time of the zones annual peak demand.
- **LRR UCAP per-unit of LRZ Peak Demand**: Zonal specific reserve margin [%], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).
- **Capacity Import Limit**: The amount of capacity that a zone can import from outside their zone reliably during peak load before observing a transmission constraint.
- **Capacity Export Limit**: The amount of capacity that a zone can reliably export out of their zone during peak load before observing a transmission constraint.

LOLE Terms and Definitions

- **Forecasted LRZ Load at MISO Peak**: Zone's load coincident with MISO's annual peak load.
- **Firm External Support:** Represents the external resources offered into planning year PRA and are modeled at the individual unit level.
- **External Non-Firm Support:** Represents the benefit of being part of the Eastern Interconnection, where 1 MW increase of no-firm support reduces requirement by 1MW.
- **Local Reliability Requirement**: Zonal specific reserve margin requirement [MW], capacity above zonal peak load, required to meet "1 day in 10" loss of load expectation requirement if the Local Resource Zone is an island (i.e. completely disconnected from external areas and the rest of MISO).

LOLE Terms and Definitions

- **Local Clearing Requirement**: The minimum capacity required to be physically located within a zone to meet the “1 day in 10” Loss of Load Expectation requirement. The LCR is LRR minus the CIL and non-pseudo tied exports.
- **Zone’s System Wide PRMR**: The zones share of the total MISO Planning Reserve Requirement that the zone needs to procure on a UCAP basis [MW]. The difference of the zones system wide PRMR minus the Local Clearing Requirement is the capacity that can be cleared outside of the zone (able to import at peak load) to meet the Planning Reserve Margin Requirement.
- **Planning Reserve Margin (PRM):** The reserve margin, capacity above peak load, the entire MISO footprint needs to procure to meet the “1 day in 10” Loss of Load Expectation requirement. The “1 day in 10” Loss of load requirement is the industry standard risk metric.

PRM and LRR Calculations

$$\text{PRM ICAP} = \frac{[\text{Installed capacity} + \text{ICAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{PRM UCAP} = \frac{[\text{Unforced capacity} + \text{UCAP Adjustment to meet 0.1 days/year LOLE} + \text{Firm Contracts}] - \text{MISO Peak Demand}}{\text{MISO Peak Demand}}$$

$$\text{Each LRZ}'\text{s LRR} = \text{LRZ Unforced Capacity} + \text{LRZ UCAP Adjustment needed to meet 0.1 d/y LOLE}$$

$$\text{LRZ per unit LRR} = \frac{\text{LRR}}{\text{LRZ Peak Demand}}$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 39

DOE Order No. 202-22-2

Department of Energy
Washington, DC 20585

Order No. 202-22-2

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 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), 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.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) 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 or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS_9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for

the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as "CA 2" and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor's August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC's Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource

provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 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. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

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

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

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

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

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

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

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

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

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.

Kathleen Hogan
Acting Under Secretary for
Infrastructure

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Filed September 5, 2025

Exhibit 40

NERC 2024 Reliability Report

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 State of Reliability

June 2024

[2024 SOR Infographic]

[2024 SOR Overview]

[2024 SOR Video]

Technical Assessment of 2023 Bulk Power System Performance

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Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- **Reliability Metrics**
- **Frequency Response Performance**
- **Generation Performance and Availability**
- **Transmission Performance and Unavailability**

Reliability Metrics

By calculating 2023 reliability metrics[70] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this chapter can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS in this manner supports NERC's obligation to assess the capability of the BPS. Table 4.1 shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name	Metric Performance Status		
M-1: Reserve Margin	**Actionable**		
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)	**Improving**		
M-3: System Voltage Performance	**Retired**		
M-4: Interconnection Frequency Response	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-4.1: Inertia and Rate-of-Change-of-Frequency	**Improving: Texas Interconnection**	**Stable: Eastern and Western Interconnections**	**Monitor: Québec Interconnection**
M-5: Activation of Under Frequency Load Shedding	**Retired**		
M-6: Disturbance Control Standard Failures	**Metric is Under Review**		
M-7: Disturbance Control Events Greater than Most Severe Single Contingency	**Metric is Under Review**		
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance	**Improving: Texas and Western Interconnections**		**Monitor: Eastern and Québec Interconnections**
M-9: Protection System Misoperations Rate	**Stable**		
M-10: Transmission Constraint Mitigation	**Retired**		
M-11: Energy Emergency Alerts	**Improving**		
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	**Improving**		
M-13: Automatic AC Transmission Outages Initiated by Human Error	**Improving**		
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	**Improving**		

[70] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.

Table 4.1: Reliability Indicators	
Metric Name	**Metric Performance Status**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment	**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	**Stable**
M-17: Transmission Outage Severity	**Stable**

Frequency Response Performance

Frequency response arrests and stabilizes frequency during system disturbances. NERC closely monitors the frequency response of each of the four Interconnections and measures the margin at which under-frequency load shedding (UFLS) would be activated. UFLS provides a vital safety net for preserving Interconnection reliability. Measuring the margin allows NERC and the industry to ensure that there is adequate frequency response on the system.

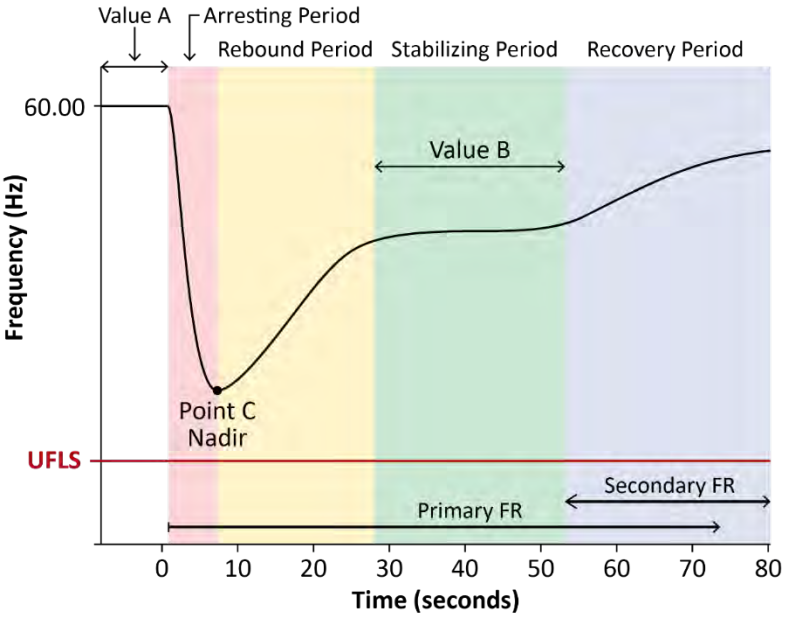


Figure 4.1: Frequency Response Methodology

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for Interconnection frequency response obligation (IFRO) under BAL-003 is based on arresting the Point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[71] for the Interconnection. Measuring and tracking the margin between the first-step UFLS set point and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first-step UFLS set point.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. Figure 4.2 indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

2023 Interconnection Frequency Response

2023 performance and trends frequency response analysis indicate an adequate level of reliability.

- For the stabilizing period, the Interconnection frequency response,[72] the Eastern Interconnection, the Québec Interconnection, and the Western Interconnection showed no statistically significant changes from 2019 through 2023. The Texas Interconnection showed a statistically significant improvement for the stabilizing period from 2019 through 2023.
- For the arresting period, the inertia and rate-of-change-of-frequency (ROCOF),[73] the Eastern and Western Interconnections showed no statistically significant changes from 2019 through 2023. The Texas

[71] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.
[72] Interconnection Frequency Response, M-4
[73] Inertia and Rate-of-Change-of-Frequency, M-4.1

Interconnection showed a statistically significant improvement. The Québec Interconnection showed a statistically significant decreasing trend.

Of note in 2023, as shown in Table 4.2, the Western Interconnection had two events within the five-year period in which the measured frequency response was less than the IFRO. Both events had a starting frequency well above 60.00 Hz and had a confirmed MW loss under 500 MW. These two factors combined alleviate concerns that the Western Interconnection frequency response is insufficient. Also, of note in 2023 was the decreasing trend in the inertia and ROCOF for the Québec Interconnection. The Québec Interconnection confirmed an overrepresentation of summer events in 2023 compared to other years (2019–2022). Twenty percent of all events in the past five years occurred between May and October 2023 (months that typically have lower inertia), in part due to the wildfire events in the region. The Eastern Interconnection, Québec Interconnection, and Texas Interconnection did not have any events within the five-year period in which the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: 5-Year Statistical Trend

Interconnection	M-4 Interconnection Frequency Response	M4.1 Inertia and Rate-of-Change-of-Frequency	Margin-C-UFLS	Comment
Eastern	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Texas	increasing	increasing	increasing	No M4 events with FR below IFRO
Québec	neither decreasing nor increasing	decreasing	neither decreasing nor increasing	No M4 events with FR below IFRO
Western	neither decreasing nor increasing	neither decreasing nor increasing	neither decreasing nor increasing	Two M4 events with FR below IFRO

Of note, the Western Interconnection has had the least number of valid events since frequency response evaluation started. This trend in reduction of valid frequency response events is suspected to be due to the retirement of large generating facilities in the Interconnection over the evaluation period and is a positive indicator when considering impacts to Interconnection reliability.

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period and arresting period as shown in Table 4.3 and Table 4.4.[74]

Table 4.3: 2023 Frequency Response Performance Statistics for Stabilizing Period

	2023 Operating Year Stabilizing Period Performance					
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Number of events with FR below the IFRO
Eastern	47	2,685	2,459	1,138	5,176	0
Texas	38	1,410	1,241	682	2,788	0
Québec	65	762	693	260	1,682	0
Western	28	2,049	1,682	912	5,050	2

[74] Frequency Response Performance Statistics

Table 4.4: 2023 Frequency Response Performance Statistics for Arresting Period								
	Operating Year (OY)							
	Number of Events	Mean Frequency Response	Median	Minimum	Maximum	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
Eastern	47	2,151	1,969	1,059	3,550	0.454	0.453	0.441
Texas	38	727	738	283	1,604	0.611	0.606	0.579
Québec	65	124	120	48	233	1.022	1.065	0.118
Western	28	868	829	544	1,554	0.415	0.421	0.332

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. The Québec Interconnection had two events at or greater than 100% of the RLPC and maintained sufficient UFLS margin. The largest events for the Eastern Interconnection and Texas Interconnection were 45% and 50%, respectively, as measured by percentage of RLPC.

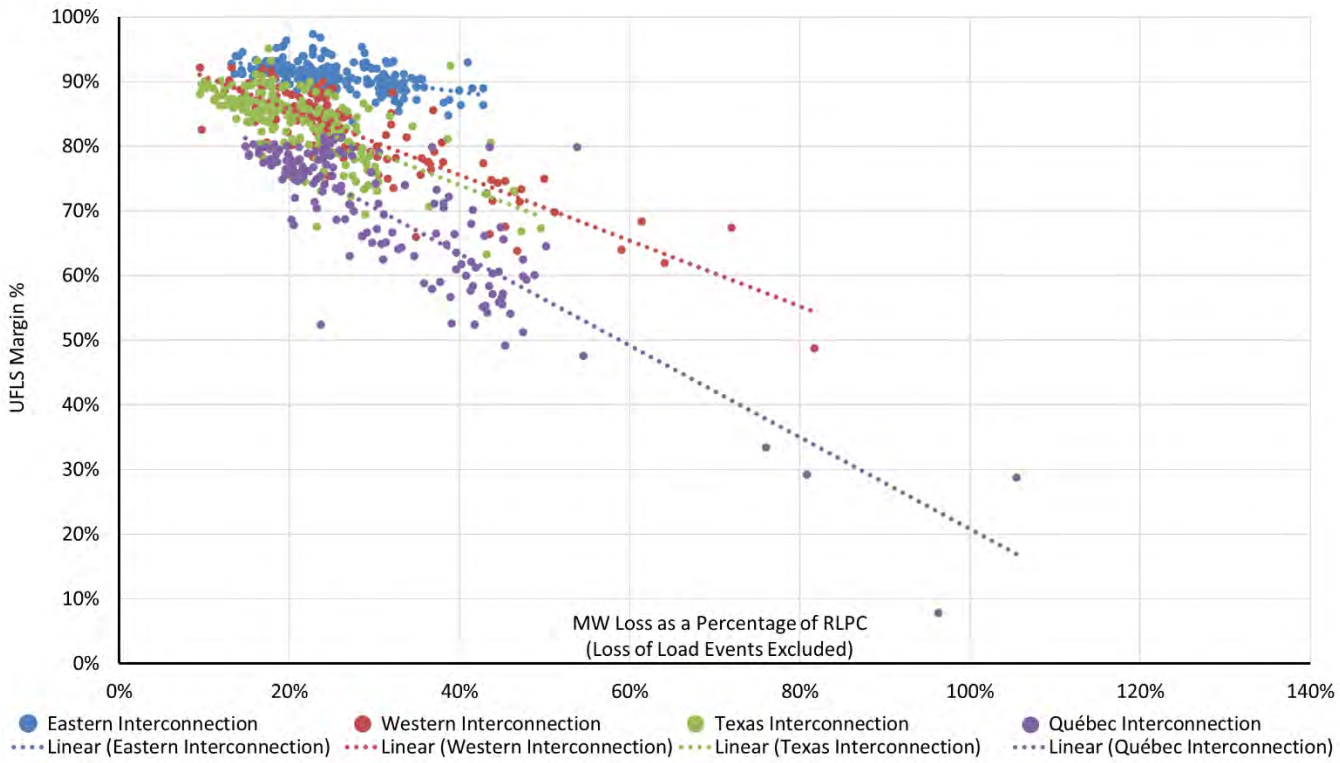


Figure 4.2: Operating Year 2019–2023 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2023 Performance and Trends

Each RC has a different methodology for determining Interconnection reliability operating limits (IROL)[75] based on the makeup of their area and what constitutes an operating condition that is less than desirable. The following discussion of performance on an Interconnection basis is for clarity, not comparison:

[75] M-8, IROL Exceedance

- **Eastern–Québec Interconnections:** In 2023, there were eight exceedances that lasted more than 10 minutes, less than the five-year average of 19.4 exceedances as shown in Figure 4.3. The 10- to 20-minute range continued to decline from its all-time peak in 2019 with zero exceedances greater than 20 minutes.
- **Western Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.
- **Texas Interconnection:** The trend has been stable with no IROL exceedances reported in 2023.

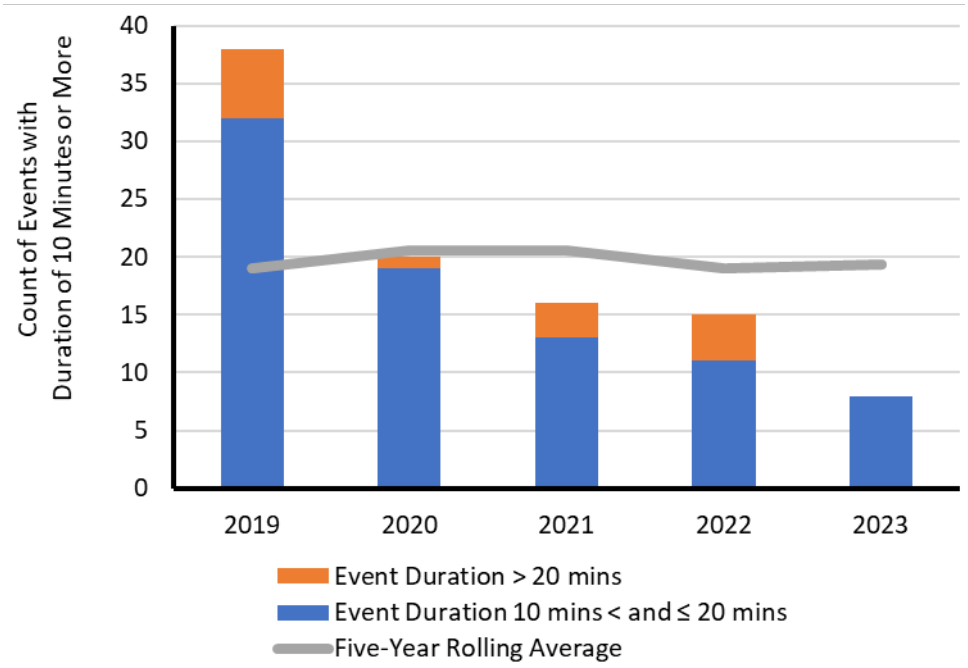


Figure 4.3: IROL Exceedance Counts[76]

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as WEFOR. GADS collects and stores unit operating information by pooling individual unit information, overall generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 7.4%. While noticeably lower than the two preceding years, the annual WEFOR of 7.8% for 2023 is the third highest since NERC began digitally collecting GADS data in 2013, despite no major outlying winter weather event.

[76] M-8, IROL Exceedance

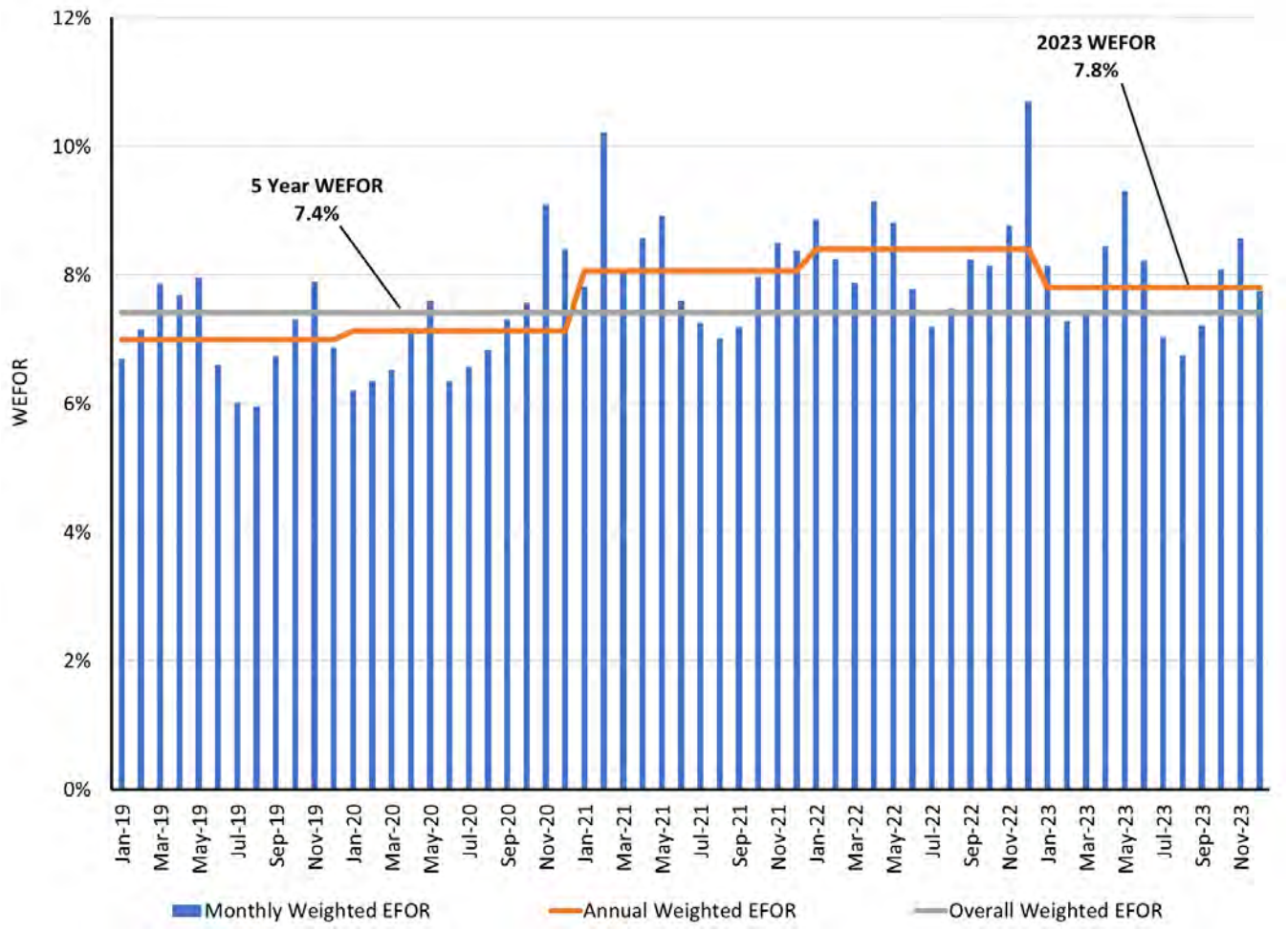


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

To better illustrate 2023's high WEFOR relative to historical norms, Figure 4.5 shows the annual WEFOR by fuel type for the past 10 years. This extended analysis period is presented to illustrate how the abnormally high WEFORs in 2021 and 2022 caused by extreme cold weather conditions obfuscate long-term trends.

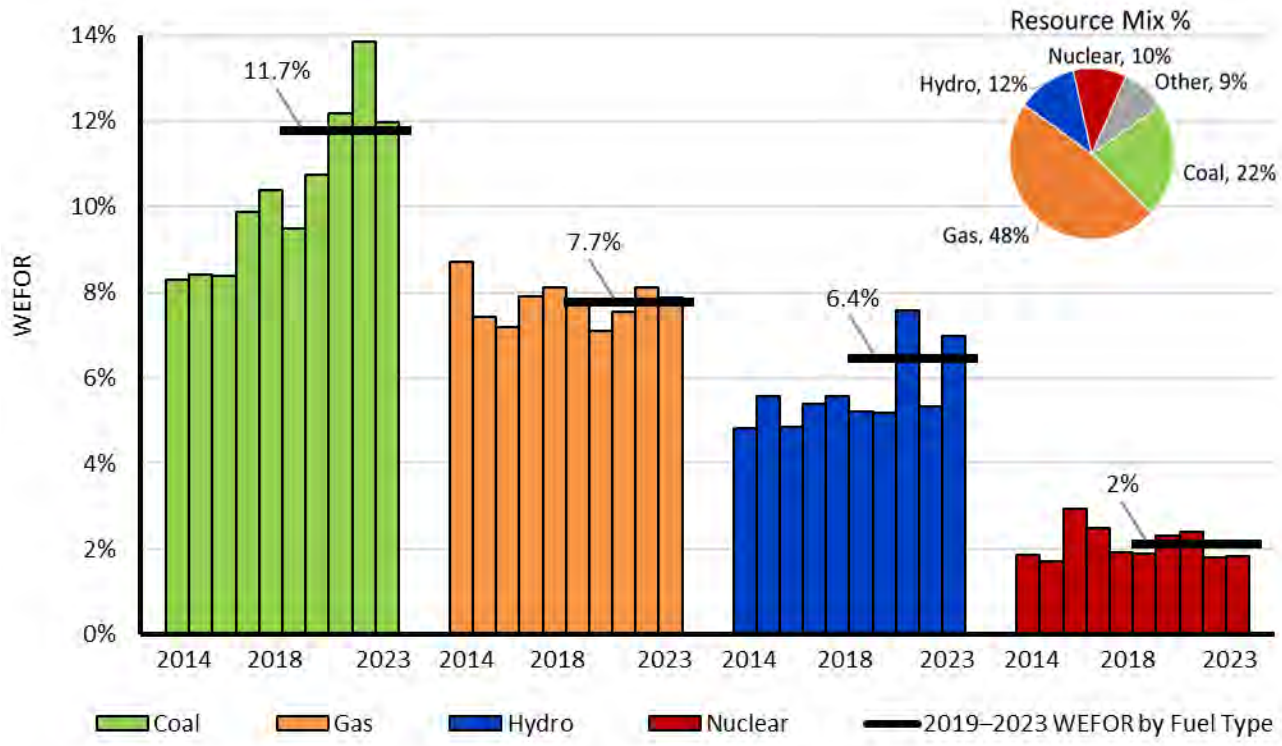


Figure 4.5: 10-Year Annual WEFOR by Fuel Type and 2023 Resource Mix by Net Maximum Capacity

Although coal-fired generation experienced a large decrease in WEFOR in 2023 (12.0% in 2023 versus 13.9% in 2022), it remains above pre-2021 rates. Due to year-over-year variability, coal generation is the primary driver of change in the overall WEFOR despite more energy being produced by both natural gas and nuclear power in 2023 (see Figure 4.6). Further investigation into baseload coal generation indicates that a unit's WEFOR negatively correlates most strongly to capacity factor.[77] Notably, once capacity factor falls below approximately 60%, unweighted average EFORs of units begin increasing more rapidly than those between 60% and 100%. Although forced-outage hours are a definite contributor to lower capacity factor units' increased WEFOR, the disproportionate change appears to be driven more by maintenance/planned outage hours and decreased service hours. This aligns with industry statements indicating that reduced investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.

Hydro units also experienced an unusually high annual WEFOR (6.9%) for the second time following one in 2021 (7.6%). However, these two relatively high years were both still lower than the associated years' overall WEFOR and do not indicate a trend at this point but warrant continued awareness.

[77] The correlation factor between capacity factor and WEFOR for baseload coal in 2023 was -0.41. While not mathematically indicative of a strong correlation (generally +/-0.7), it is notably stronger than any other aspect that is not a direct component of the WEFOR with the next highest being age (0.18) and planned outage hours (-0.16) given the relatively small sample size and amount of variation between coal units.

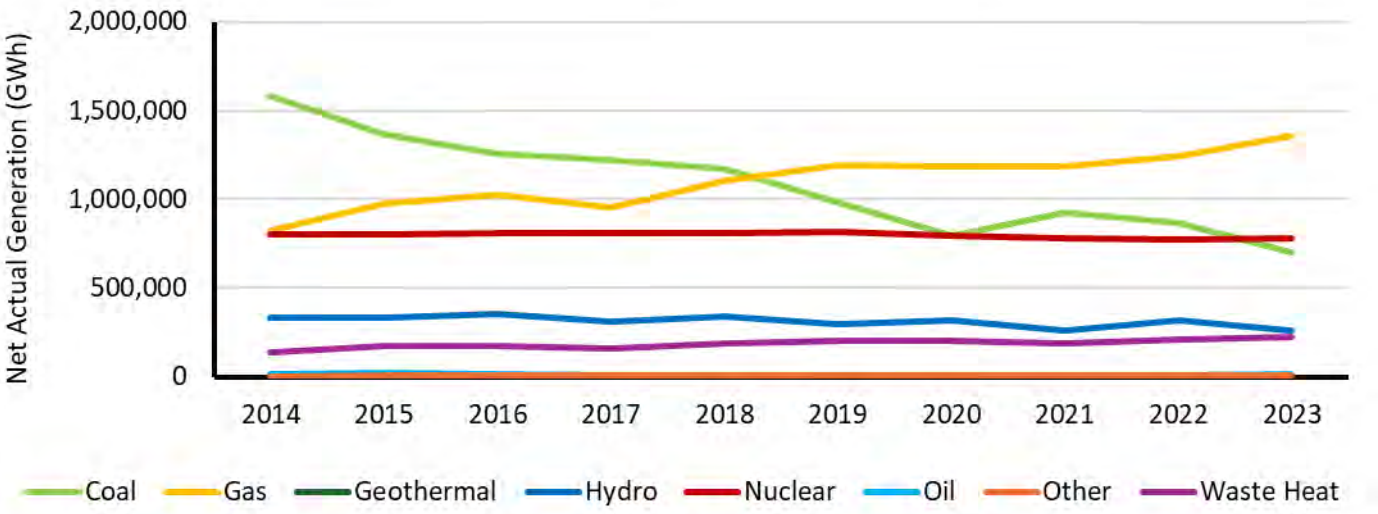


Figure 4.6: 10-Year Annual Conventional Net Actual Generation (GWh) by Fuel Type

Wind Generation Weighted Resource Forced-Outage Rate

NERC began collecting wind performance data with a phased-in approach based on plant size starting with a total installed capacity of 200 MW or greater in 2018 followed by plants with a total installed capacity of 100–199 MW in 2019 and plants with a total installed capacity of 75–99 MW in 2020 (see Figure 4.7). By the end of 2023, data from 137,737 MW of installed capacity, representing 703 wind plants across North America and 13% of nameplate generation, was reported to NERC. Data will continue to be reported separately for the reporting phase groups until sufficient history is available to analyze trends for a five-year rolling period across all wind plants comparable to the analysis for conventional generation. Specific event data collection for wind and solar began in 2024 and will allow for further analysis.

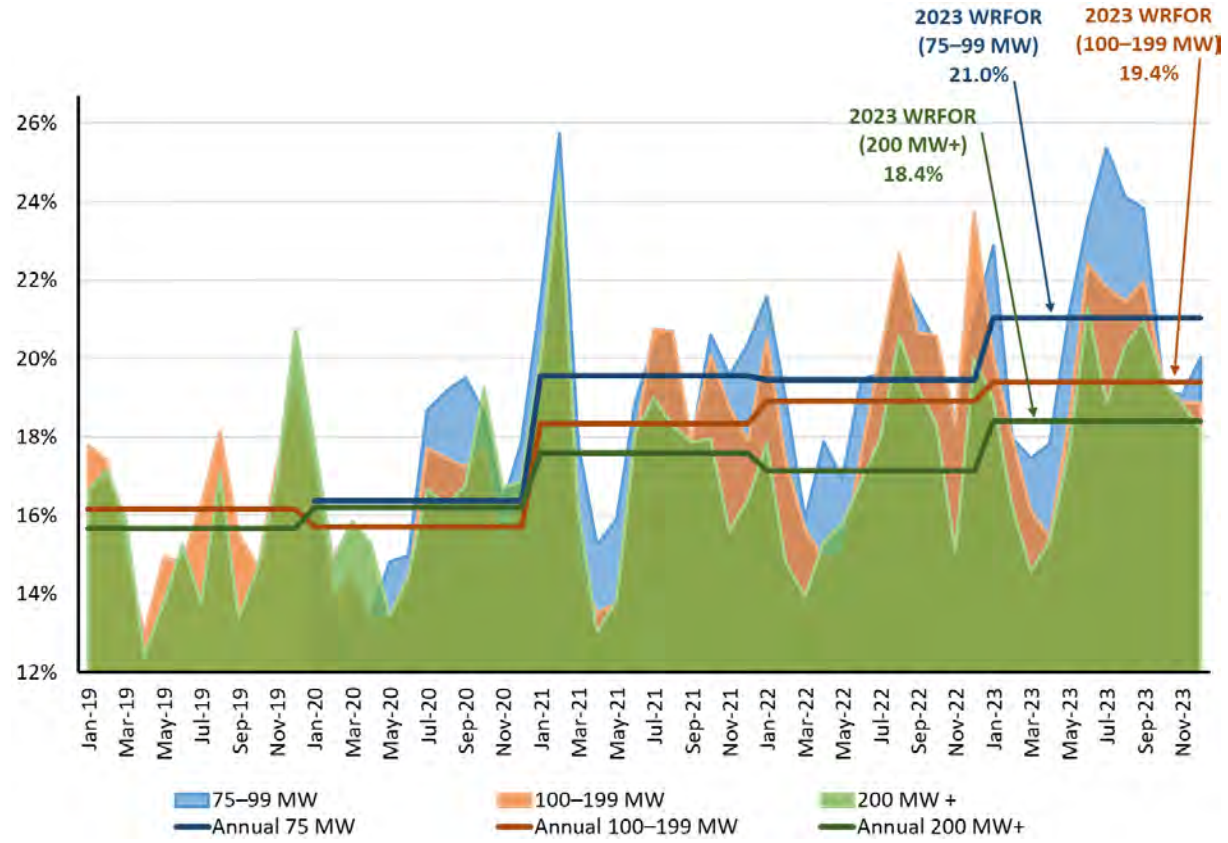


Figure 4.7: Monthly Capacity and Annual Average WRFOR Wind Plant Reporting Group

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS. The number of qualified events that include transmission outages that resulted in firm load loss not related to weather is provided in the following subsection.

Transmission-Related Events Resulting in Loss of Load

In 2023, a total of nine distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (see Figure 4.8). The median firm load loss over the past five years was 97 MW, which is a decrease from 2018–2022's 101 MW. Although, notably, the median load loss was 113 MW in 2023, which is above the five-year median value, no discernible trend in the number of events or amount of loss is identifiable.

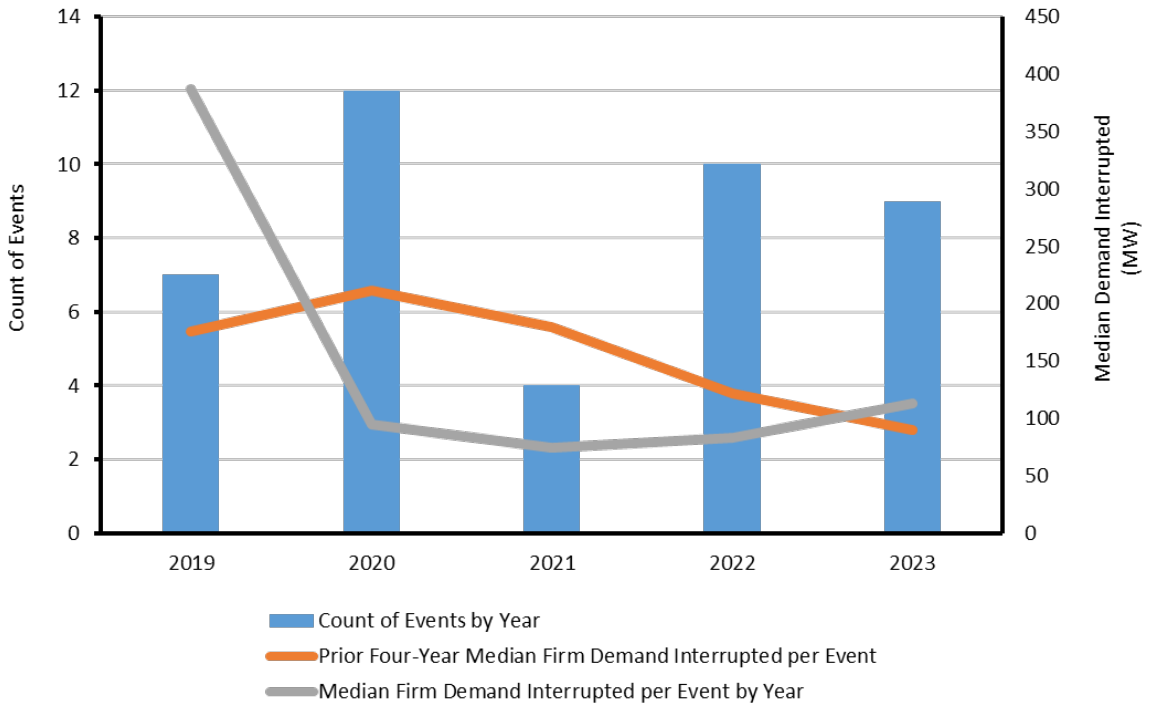


Figure 4.8: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[78]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

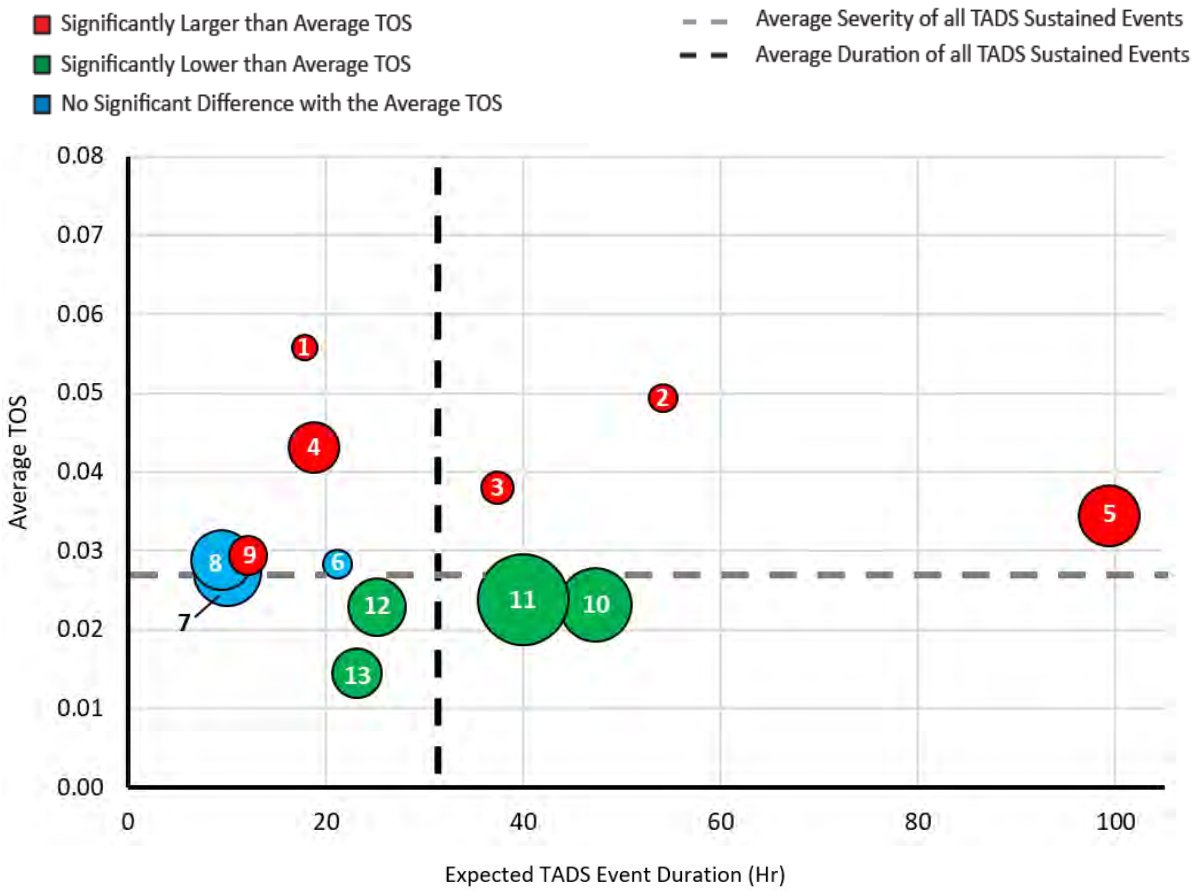
- **Transmission Outage Severity**
- **Automatic AC Transmission Outages**
- **Transmission Element Unavailability**

Transmission Outage Severity

The impact of a TADS event on BPS reliability is called the TOS of the event, which is defined by the number of outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

[78] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (see Figure 4.9), it is possible to determine which ICCs contribute most to reliability performance for the considered period. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Change in size or position of a bubble with the same number (identifying ICC) may indicate improved or declined performance. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups. The number of events per hour, average event duration, and average TOS for each ICC group are shown in Table 4.5.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.9: TOS vs. Expected TADS Event Duration

Table 4.5: TOS vs. Expected TADS Event Duration			
TADS Event	**Events per Hour**	**Average TOS**	**Average Event Duration**
Power System Condition	.012	.056	17.9
Fire	.014	.049	54.2
Combined Smaller ICC Groups	.019	.038	37.4
Misoperation	.046	.043	18.8
Failed AC Substation Equipment	.068	.034	99.4
Other	.015	.028	21.2
Unknown	.085	.027	10.0
Lightning	.067	.029	9.5
Human Error	.026	.029	12.2
Failed AC Circuit Equipment	.098	.023	47.3
Weather, Excluding Lightning	.153	.024	40.0
Foreign Interference	.061	.023	25.2
Vegetation	.045	.014	23.2

An analysis of the total TOS by year indicates that 2023 was an outlier from the statistically improving trend identified over the previous five years. Figure 4.10 shows the annual TOS, which is the third highest over the last five years; the shaded area shows the effect of the Québec wildfires on the 2023 TOS.

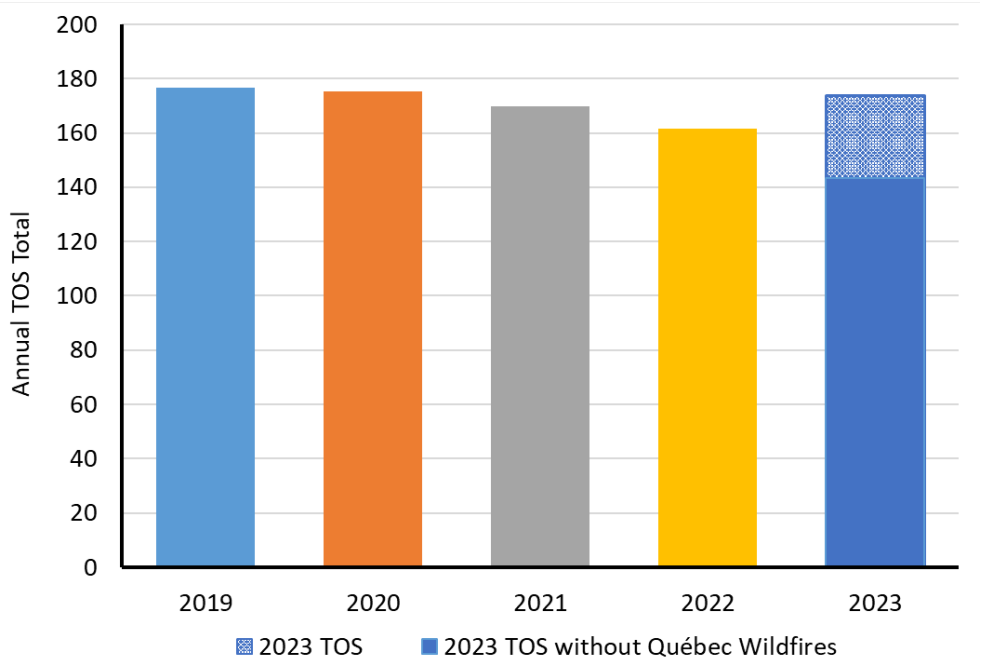


Figure 4.10: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[79]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment has continued to improve consistently over the last four years, showing a statistically significant decrease in 2023 compared to 2019–2022 (see Figure 4.11 The number of sustained outages due to failed ac circuit equipment per 100 miles saw a decrease in 2023 (see Figure 4.12).

[79] M-17, Transmission Outage Severity

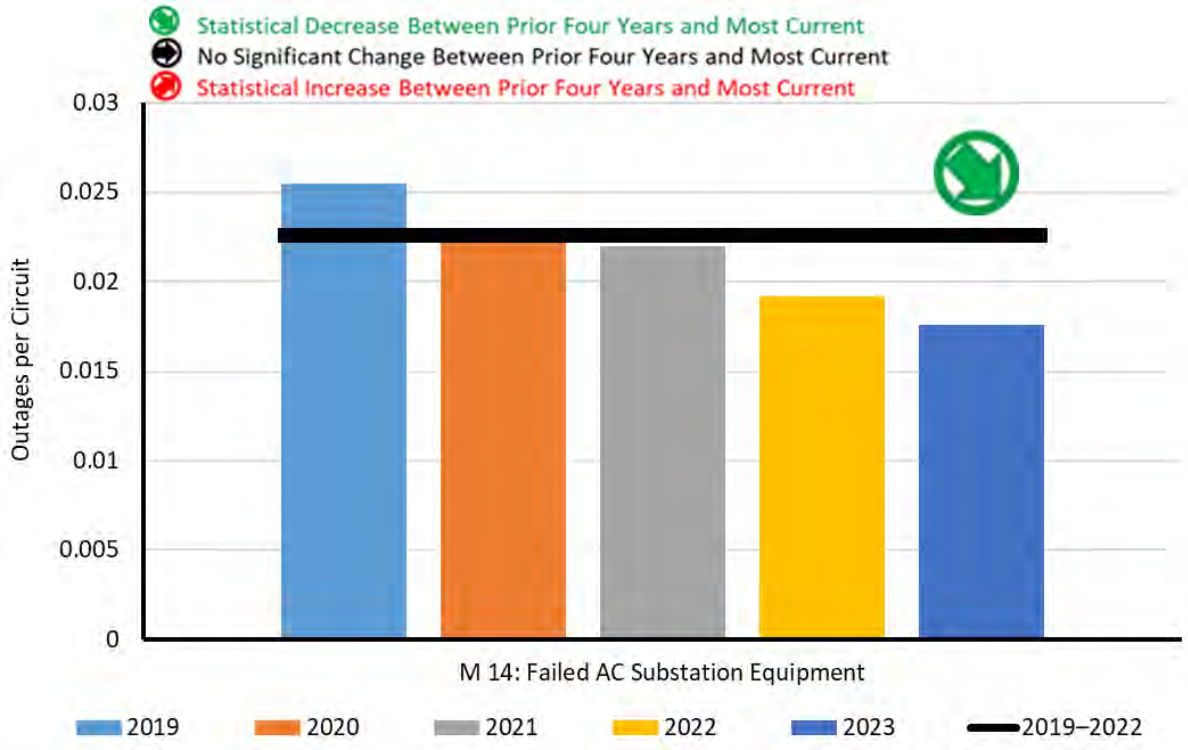


Figure 4.11: Number of Outages per AC Circuit Due to Failed AC Substation Equipment[80]

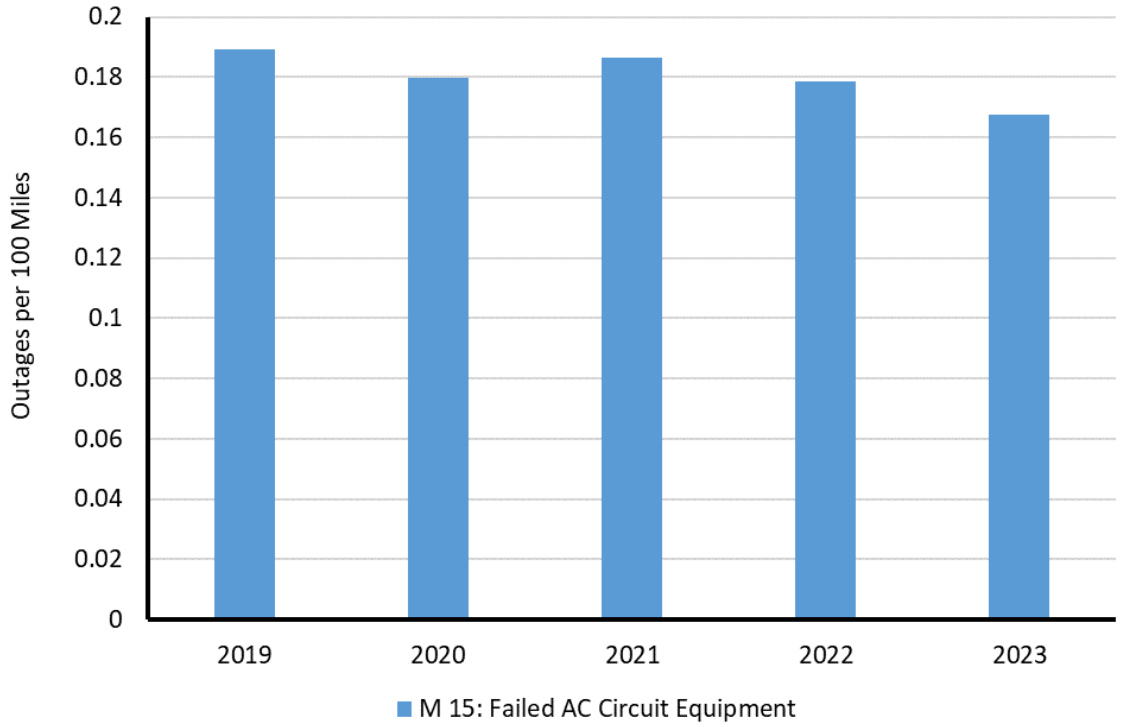


Figure 4.12: Number of Outages per 100 Miles Due to Failed AC Circuit Equipment[81]

[80] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment
[81] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Automatic AC Transformer Outages

In 2023, the number of automatic ac transformer outages per element caused by failed ac substation equipment was statistically equal to 2019–2022 (see Figure 4.13); the overall average remains stable.

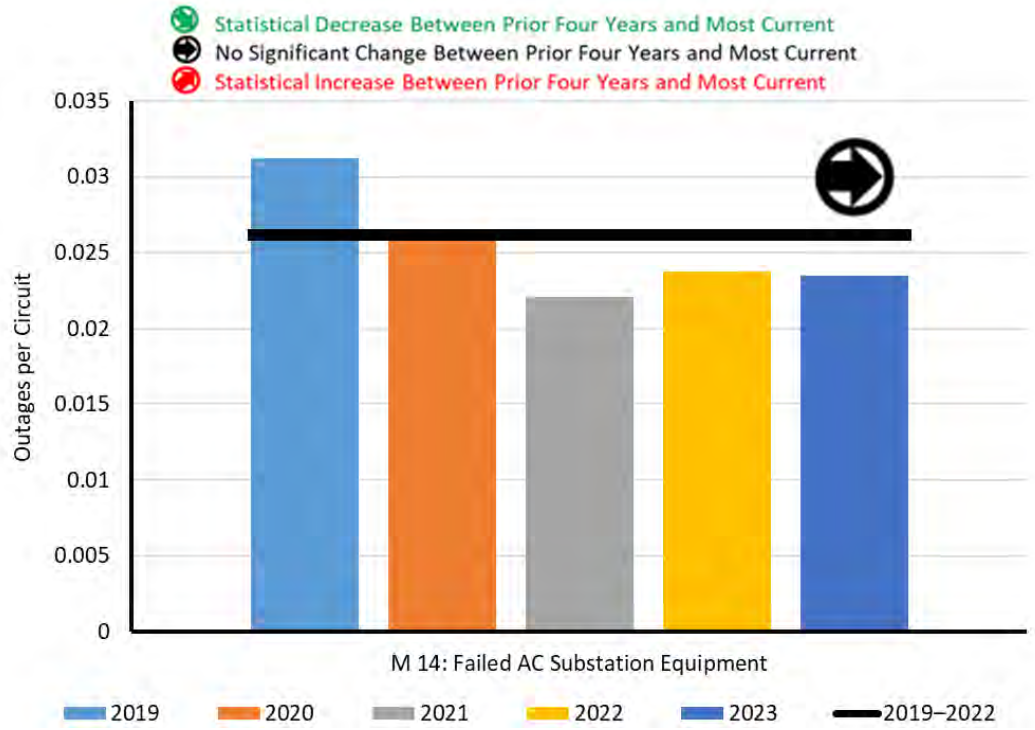


Figure 4.13: Number of Outages per Transformer Due to Failed AC Substation Equipment[82]

Transmission Element Unavailability

In 2023, ac circuits over 200 kV across North America had an unavailability rate of 0.24%, meaning that there is a 0.24% chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers had an unavailability rate of 0.25% in 2023. Figure 4.14 shows that 2023 was the lowest year for ac circuit unavailability of the five-year analysis period. Figure 4.15 shows that 2023 was the second-highest year for transformer unavailability of the five-year analysis period.

[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

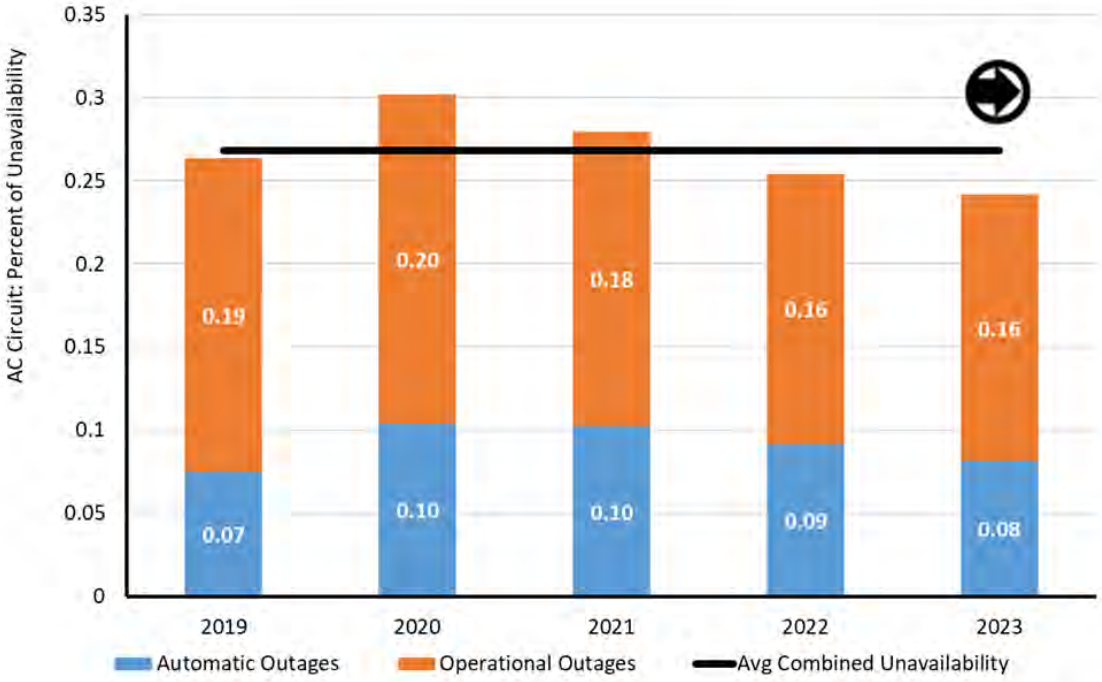


Figure 4.14: AC Circuit Unavailability > 200 kV[83]

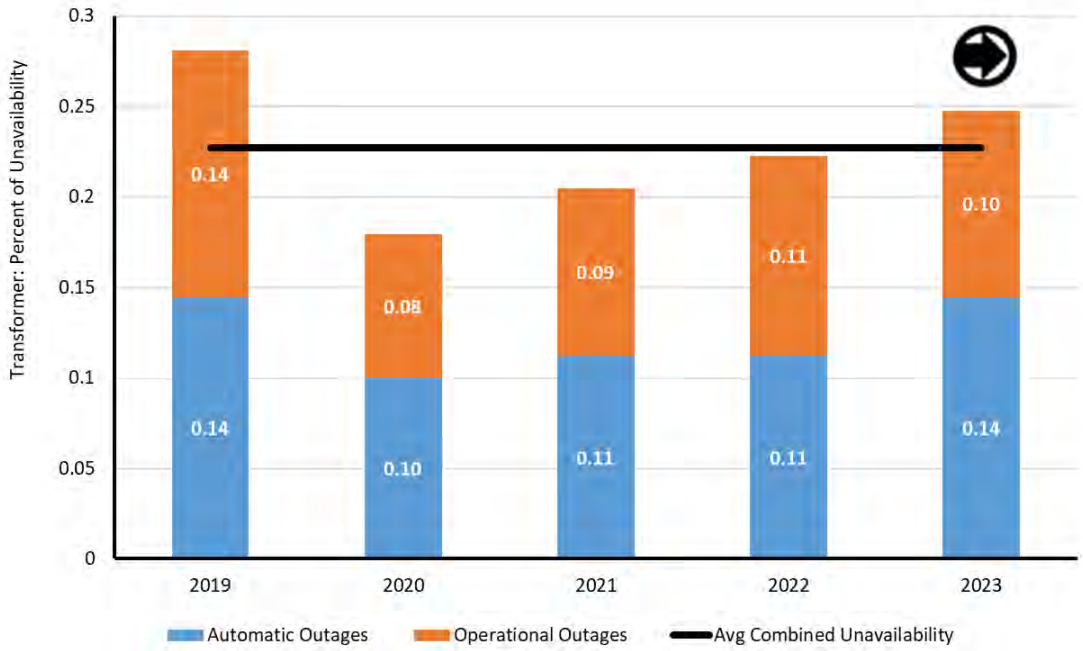


Figure 4.15: Transformer Unavailability[84]

[83] M-16, Element Availability Percentage (APC) & Unavailability Percentage
[84] Ibid.