Consumers Energy
Count on Us

September 30, 2024

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

**RE: Case No. U-21592 – 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.**

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find **Consumers Energy Company's Application with supporting Testimony and Exhibits of Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Zachery S. Cole, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Angela K. Rissman, Beth A. Skowronski, and Andrew G. Volansky**.

This is a paperless filing and is therefore being filed only in PDF. Also included is a Proof of Service showing service upon the parties in Case No. U-21423.

Sincerely,

Digitally signed by Evan B. Keimach
Date: 2024.09.30 14:06:53 -04'00'

Evan B. Keimach
Phone: 517-788-1350
Email: evan.keimach@cmsenergy.com

cc: Parties to MPSC Case No. U-21423

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**APPLICATION**

Consistent with 1982 Public Act 304 ("Act 304"), MCL 460.6j, as amended, Consumers Energy Company ("Consumers Energy" or the "Company") seeks approval of a Power Supply Cost Recovery ("PSCR") Plan and monthly PSCR factors for the 12-month period January through December 2025. In support of this Application, Consumers Energy states the following:

1. Consumers Energy is a public utility engaged in, among other things, 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.

2. Consumers Energy's retail electric business is subject to the jurisdiction of the Michigan Public Service Commission ("MPSC" or the "Commission") under 1939 Public Act 3, as amended by various acts, including Act 304, and other applicable laws.

3. This Application is filed consistent with Act 304 and Rule C8 of Consumers Energy's electric tariffs. Act 304 authorizes the Commission to approve a PSCR clause for electric utilities like Consumers Energy. MCL 460.6j. Company Rule C8 sets forth the Company's PSCR clause. Rule C8, Tariff Sheets C-35.00–C-36.00.

4. Under Act 304, utilities are to be reimbursed for booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs of fuel burned by utilities for electric generation, as well as the booked costs of purchased and net interchanged

power transactions incurred under reasonable and prudent policies and practices. Generally, it is in the interests of both customers and the Company for Consumers Energy to recover its power supply costs during the PSCR period in which those costs are incurred, although times of unforeseen elevated and volatile pricing may merit the recovery of reasonable and prudent costs over an extended period.

5. Rule C8 requires the Company to file a PSCR Plan, to request approval of specific PSCR factors for a future 12-month period, and to provide a five-year forecast. To meet these requirements, Consumers Energy files this Application, together with supporting testimony and exhibits, proposing a PSCR plan and factors for the 2025 calendar year. Also included with this Application is the Company's five-year forecast of its power supply requirements, anticipated sources of supply, and projections of power supply costs. The Company's forecasted costs of fuel and purchased and net interchange power are reasonable and prudent, and the decisions underlying its five-year forecast are sound.

6. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2025, a uniform maximum PSCR factor that consists of the sum of two parts: a base PSCR ceiling factor of $0.00909 per kWh for all classes of customers ***plus*** additional amounts contingent upon future events. The Commission is authorized to approve PSCR ceiling price adjustments contingent on future events pursuant to Section 6j(6) of 1982 PA 304, as amended, MCL 460.6h(6).

7. Consumers Energy is proposing a PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism for the 2025 PSCR Plan year. The PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism would:

(i) allow an increase above the base PSCR Plan Ceiling Factor to reflect increases in New York Mercantile Exchange ("NYMEX") prices if the updated 12-month forecast is greater than the 12-month forecast that was used in developing the PSCR Plan Ceiling Factor;

(ii) recognize NYMEX price increases in $0.25 increments with fixed dollar amounts per unit of electricity identified as the contingent PSCR factor for each step-wise increase in NYMEX pricing; and

(iii) include a $4.00 ceiling on increases in the NYMEX Price Forecast that would be considered in adjusting the base PSCR Plan Ceiling Factor.

Consumers Energy anticipates that these provisions will help meet goals of matching costs incurred with cost charged during the PSCR period, help send more accurate price signals to customers, and help reduce future under-recoveries. Consumers Energy is proposing that a review of the NYMEX price forecast occur monthly.

8. As shown on Exhibit A-25 (AGV-1), the Company's proposed maximum PSCR factor incorporates the portion of the underrecovery identified in the Commission's February 23, 2023 Order Approving Temporary Power Supply Cost Recovery Factors, and in its August 30, 2023 Order Approving Settlement Agreement in Case No. U-21257 (the Company's 2023 PSCR plan case). Through these orders, the Company was authorized to incorporate one-third of its projected 2022 power supply cost underrecovery into its and 2025 PSCR plan year for recovery.

9. The accompanying testimony and exhibits, as provided by Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Zachary S. Cole, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Angela K. Rissman, Beth A. Skrowronski, and Andrew G. Volansky, are an integral part of this Application, and the relief described in the testimony and exhibits is incorporated by reference. This testimony includes a description of the generation resources required to meet customer capacity needs and any necessary capacity purchases; projected plant outages and projected cost of the various sorbents used in the generation of electricity; projected cost of the fuel used in the generation of electricity; and projected transmission-related and energy market costs.

10. If power supply costs increase for the PSCR Plan year, due to changes in conditions, the factors that are ultimately requested or approved could be higher than described above. Consumers Energy reserves the right to amend its filing or seek reopening of the power supply cost review for the PSCR Plan year if circumstances warrant.

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

A. Issue a prompt notice scheduling hearings on the relief sought;

B. Approve, for 2025, a maximum monthly PSCR factor consisting of the sum of two parts: (i) a base ceiling factor of not less than $0.00909 per kWh for all classes of customers ***plus*** (ii) additional amounts contingent on future events, determined using the PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism, as described above and more fully explained in the accompanying testimony and exhibits;

C. Approve the PSCR Plan for 2025 described in this Application; and

D. Grant Consumers Energy any further relief that may be lawful and appropriate.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Date: September 30, 2024

By: Sri M.

Srikanth Maddipati
Vice President of Electric Supply
Consumers Energy Company

Evan B. Keimach (P83418)
Spencer A. Sattler (P70524)
Bret A. Totoraitis (P72654)
Attorneys for Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201
Phone: 517-788-1350

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**VERIFICATION**

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

Date: September 30, 2024

By: Sri M.

Srikanth Maddipati
Vice President of Electric Supply
Consumers Energy Company

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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|---|---|---|
| In the matter of the application of | ) | |
| **CONSUMERS ENERGY COMPANY** | ) | |
| for approval to implement a power supply | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**DIRECT TESTIMONY**

**OF**

**DANIEL S. ALFRED**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**QUALIFICATIONS**

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

A. My name is Daniel S. Alfred, and my business address is 1945 West Parnall Road, Jackson, Michigan 49201.

**Q. By whom are you employed?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company").

**Q. What is your position with Consumers Energy?**

A. I am a Strategy Manager in the Electric Supply Regulatory Strategies group.

**Q. Please describe your educational background.**

A. I received a Bachelor of Business Administration in Accounting degree in 1993 from Eastern Michigan University. I received a Master of Business Administration Degree with an emphasis in finance from Eastern Michigan University in April 2003.

**Q. Please describe your business experience.**

A. In January 1998, I joined Consumers Energy as a Rate Analyst in the Financial Analysis and Planning Section of the Rates Department and was promoted to General Rate Analyst in October 1999. During August 2001, I transferred to a position in the Revenue Requirements section of the Rates Department. In February 2004, I was promoted to a Senior Rate Analyst in the Revenue section of the Rates and Business Support Department. In March 2013, I assumed the position of Senior Rate and Business Support Consultant in the Transmission and Regulatory Strategies Section of Energy Supply Operations. In June 2020, I was promoted to the position of Principal Rate Analyst. In July 2023, I was promoted to my current position of Strategy Manager.

**Q. What are your responsibilities as a Strategy Manager?**

A. In this position, I am responsible for monitoring and analyzing the filings by the Midcontinent Independent System Operator, Inc. ("MISO") at the Federal Energy Regulatory Commission ("FERC"). In addition, I support the Company's involvement in stakeholder and transmission planning activities at MISO, FERC, and the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for forecasting future transmission and certain energy market-related costs expected to impact the Company.

**Q. During your tenure with Consumers Energy, have you testified in any utility proceedings before the Commission?**

A. Yes. I have testified or submitted testimony in the following proceedings:

| | |
|---|---|
| Case No. U-13730 | Gas General Rate Case; |
| Case No. U-14126 | Enhanced Security Costs; |
| Case No. U-14148 | 10d(4) Regulatory Asset Recovery; |
| Case No. U-14347 | Electric General Rate Case; |
| Case No. U-15245 | Electric General Rate Case; |
| Case No. U-15986 | Gas General Rate Case; |
| Case No. U-15704 | Gas Cost Recovery Plan; |
| Case No. U-14126-R | Enhanced Security Costs Reconciliation; |
| Case No. U-16564 | 10d(4) Regulatory Asset Reconciliation; |
| Case No. U-16855 | Gas General Rate Case; |
| Case No. U-17317 | 2014 Power Supply Cost Recovery ("PSCR") Plan Case; |
| Case No. U-17678 | 2015 PSCR Plan Case; |
| Case No. U-17918 | 2016 PSCR Plan Case; |

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| Case No. U-18142 | 2017 PSCR Plan Case; |
| Case No. U-18402 | 2018 PSCR Plan Case; |
| Case No. U-20219 | 2019 PSCR Plan Case; |
| Case No. U-20525 | 2020 PSCR Plan Case; |
| Case No. U-20802 | 2021 PSCR Plan Case; |
| Case No. U-21048 | 2022 PSCR Plan Case; |
| Case No. U-21257 | 2023 PSCR Plan Case; and |
| Case No. U-21423 | 2024 PSCR Plan Case. |

**PURPOSE OF DIRECT TESTIMONY**

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

A. The purpose of my direct testimony is to: (i) identify the transmission and energy market expenses for 2025 for which the Company seeks recovery in this proceeding; and (ii) describe the Company's effort to manage its transmission-related costs.

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

A. Yes. I am sponsoring the following exhibit:

| | |
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| Exhibit A-1 (DSA-1) | Transmission and Energy Market Administration Expenses. |

**Q. Was this exhibit prepared by you or under your direct supervision?**

A. Yes.

**TRANSMISSION AND ENERGY MARKET EXPENSES**

**Q. What transmission and energy market expenses does the Company seek recovery for in the Company's 2025 PSCR Plan?**

A. The Company seeks to recover all of the charges imposed on the Company under MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff") which is filed with and approved by FERC.

**Q. Has the Commission previously approved the recovery of Transmission, Energy, and Operating Reserve Market ("Market") costs through the PSCR process?**

A. Yes. The Commission approved recovery of expenses incurred under MISO's Tariff in the Company's PSCR factor most recently in the 2023 PSCR Plan, Case No. U-21257.

**Q. Are the rates assessed and revenues distributed by MISO subject to FERC review?**

A. Yes. All of the charges incurred and revenues received through MISO by the Company are based on the FERC-approved Tariff.

**Q. Please list each transmission and energy market charge that has been projected for 2025 in the Company's total transmission costs.**

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2025 and shown in Exhibit A-1 (DSA-1), page 1, are incurred as a result of the mandated expenses charged to Consumers Energy by MISO pursuant to MISO Schedules 1, 2, 9, 10, 10-FERC, 16, 17, 24, 26, 26-A, 33, 49, and 50. The charges imposed pursuant to these schedules are discussed more fully below.

**Q. Has the Company forecasted other MISO charges?**

A. Yes. As discussed by Company witness Beth A. Skowronski in her direct testimony in this case, the impact of other MISO charges is included in the projection of energy costs.

**Q. Are your projections based on the demand and sales information provided by Company witness Eugène M.J.A. Breuring?**

A. Yes.

**Q. Please describe the MISO Schedule 1 rate and the forecasted cost of this expense.**

A. MISO Schedule 1 is the Tariff schedule for service required to schedule the movement of power through, out of, within, or into a control area, and is provided by the transmission operators within the control area and MISO. The rate for this service is a zonal rate. Applying this rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2025 PSCR Plan year and the five-year period 2025 through 2029 is shown on Exhibit A-1 (DSA-1), line 18, Schedule 1 – System Control and Dispatch.

**Q. Please describe the MISO Schedule 9 rate and the forecasted cost of this expense.**

A. MISO Schedule 9 is the Tariff schedule for the network transmission service. Schedule 9 includes the rate that applies to the Company's entire retail load within the MISO footprint. MISO utilizes the "license plate" rate approach, which means that the rate applicable to each customer is that of the transmission owner(s) in the pricing zone where the load is located. The Company pays the rate for the Michigan Joint Zone ("MJZ"). The MJZ is made up of multiple transmission owners which include Michigan Electric Transmission Company ("METC"), Wolverine Power Supply Cooperative, and Michigan Public Power Agency which all reside within the METC footprint. The rate that is assessed to load in the joint zone is an average of the joint zone members' revenue requirements. The MJZ was approved by FERC in Docket No. ER02-2458.

This rate is calculated per the MISO Tariff Attachment O. The Company's forecasted expense for the 2025 PSCR Plan year and the five-year period 2025 through 2029 is shown on Exhibit A-1 (DSA-1), line 20, Schedule 9 – Network Transmission Service.

**Q. Please describe the MISO Schedule 10 rates and forecasted cost of this expense.**

A. MISO Schedule 10 is the Tariff schedule for MISO expenses associated with the operation of MISO in the provision of transmission service within the MISO footprint. MISO assesses Schedule 10 with two rates. The first rate is applied to peak load at a 100% load factor. The Company's forecasted expense for the 2025 PSCR Plan year and the five-year period 2025 through 2029 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 21, Schedule 10 ISO Cost Recovery Adder – Demand Basis. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for the 2025 PSCR Plan year and the five-year period 2025 through 2029 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 22, Schedule 10 – ISO Cost Recovery Adder – Energy Basis.

**Q. Please describe the MISO Schedule 10-FERC rate and the forecasted cost of the expense.**

A. MISO Schedule 10-FERC is the Tariff schedule for the FERC Annual Fee that MISO is assessed and then allocated to MISO's wholesale transmission customers. The FERC Annual Fee is designed to reimburse the federal government for all of the costs incurred by FERC under Parts II and III of the Federal Power Act and related statutes per 18 CFR Part 382. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 23, Schedule 10 – FERC – ISO Cost Recovery Adder – FERC Annual Charge.

**Q. Please describe the MISO Schedule 16 rate and forecasted cost of expense.**

A. MISO Schedule 16 is designed to recover MISO administrative service costs associated with the MISO Financial Transmission Rights market. In forecasting the Schedule 16 expense, I multiplied the Company's monthly coincident peak load at a 100% load factor against the MISO budgeted Schedule 16 rate to produce the expected expense. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 24, Schedule 16 – Financial Transmission Rights.

**Q. Please describe the MISO Schedule 17 rate and forecasted cost of expense.**

A. MISO Schedule 17 is designed to recover MISO administrative service costs associated with the Midwest Energy and Operating Reserves Market. The rate is charged to all injections and withdrawals in the market. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 25, Schedule 17, ISO Cost Adder – Energy Markets.

**Q. Please describe the MISO Schedule 24 rate and forecasted cost of expense.**

A. MISO Schedule 24 is the Tariff schedule for the Control Area Operator Cost Recovery charge used to recover Control Area costs incurred with the implementation of the MISO Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 26, Schedule 24 – Balancing Area Cost Adder – Energy Markets.

**Q. Please describe the MISO Schedule 26 rate and forecasted cost of expense.**

A. MISO Schedule 26 is the Tariff schedule for the Network Upgrade Charge from MISO's Transmission Expansion Plan ("MTEP"). This schedule is applied on the same basis as Schedule 9. It reflects the sharing of MTEP project costs as allocated according to Attachment FF of the MISO Tariff. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 27, Schedule 26 – Network Upgrade Charge from Transmission Expansion Plan.

**Q. Please describe the MISO Schedule 26-A rate and forecasted cost of expenses.**

A. MISO Schedule 26-A is the Tariff schedule that includes the Multi-Value Project Usage Rate and is a MISO System-wide rate charged to Monthly Net Actual Energy Withdrawals, certain Export Schedules, and Through Schedules. The rate is calculated using the formula included in Attachment MM of the Tariff. The charges under this Schedule 26-A are in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged in this Schedule. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 28, Schedule 26-A – Multi-Value Project Usage Rate.

**Q. Will the Company be providing Blackstart Service in the 2025 Plan Year?**

A. Yes. The Company will provide Blackstart Service within the METC Transmission Pricing Zone and collect charges via MISO Schedule 33 as set forth in the MISO Tariff. The Company's forecasted expenses for the 2025 PSCR Plan year and the five-year period 2025 through 2029 are shown on Exhibit A-1 (DSA-1), line 29, Schedule 33 – Blackstart Service.

**Q. Please describe the MISO Schedule 49 rate and forecasted cost of expenses.**

A. MISO Schedule 49 is the Tariff schedule for Regional Directional Transfer Payments which is MISO's method of allocating Settlement Agreement costs associated with Available System Capacity usage of the Southwest Power Pool "SPP" and the Joint Parties. I have used last year's 2023 actual historical cost as the basis for the 2025 plan year amount which is shown on Exhibit A-1 (DSA-1), line 32, Schedule 49 – Regional Directional Transfer Payments.

**Q. Please describe the MISO Schedule 50 rate and forecasted cost of expenses.**

A. Schedule 50 is a new MISO schedule relating to the annual interconnection customer operation and maintenance and overheads charge designed to enable Transmission Owners to recover their expenses for the operation, maintenance, and repair of Transmission Owner Interconnection Facilities ("TOIF"). I have forecasted this amount according to our actual 2023 historical year expense as the basis for the 2025 plan year amount which is shown on Exhibit A-1 (DSA-1), line 31, Schedule 50 – TOIF.

**Q. What is the total amount of transmission and energy market expenses that you propose to add to the total power costs in each year of the PSCR Plan?**

A. Each of the expenses described above, as well as the total expenses for each plan year, is identified on Exhibit A-1 (DSA-1). The total cost for 2025 equals $583,999,104 and can be found on Exhibit A-1 (DSA-1), page 1, line 35, column (o). It is composed of $576,390,838 of transmission expenses (line 33, column (o) and $7,608,267 of energy market administration expenses (line 34, column (o).

## SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

**Q. Has the Company projected any Schedule 2 revenues in this case?**

A. No. On December 2, 2022, FERC suspended the collection of Schedule 2 Reactive Compensation in the MISO footprint. The Company will neither collect Schedule 2 revenue nor incur Schedule 2 expenses until FERC orders otherwise in a future FERC order.

**COMPANY ACTIVITIES RELATED TO TRANSMISSION COST MANAGEMENT**

**Q. Does the Company take actions to mitigate transmission-related costs?**

A. Yes. The Company actively participates in the transmission provider's stakeholder process addressing transmission planning and project approvals. Engagement in the stakeholder process is the primary advocacy path the Company has to assure new transmission investments are justified and allocated on a cost-causation basis. Additionally, the Company actively monitors and intervenes in tariff filings by MISO and transmission owners to assure that the new tariff provisions are in compliance with FERC policy and are based on cost-causation principles.

**Q. Is the Company involved in other activities to mitigate transmission-related costs?**

A. Yes. Under the FERC-approved MISO Tariff, transmission owners recover their Operations and Maintenance, Depreciation, and Tax expenses, as well as a Return on Investment through an "Attachment O" formula rate that utilizes the actual costs incurred and reported on the transmission owners' FERC Form 1 reports. The Company actively reviews the "Attachment O" rates of the MJZ transmission owners to assure the application of the formula is consistent with the tariff.

**Q. Can you identify some MISO stakeholder groups the Company actively follows that impact transmission expenses?**

A. Yes. The Company has been very active in MISO's transmission-related groups such as the East Sub-regional Planning Meetings, Michigan Technical Study Task Force, Planning Advisory Committee, Planning Subcommittee, Advisory Committee, Regional Expansion Criteria and Benefits Task Force, and the MISO Board of Directors System Planning

Committee. The Company's focus is to monitor, advocate, and assure new transmission projects are justified, and costs are allocated according to cost-causation principles.

**Q. How does participating in these groups impact the Company's transmission expense?**

A. By actively participating in the stakeholder process regarding proposed transmission projects, the Company can independently validate the need for the project before the project is approved by the MISO Board of Directors in the MTEP. If the Company does not believe a project is needed, it can raise issues with MISO before the project is approved.

**Q. Does that mean that MISO will reject a project Consumers Energy or another customer or interested party does not believe is needed?**

A. No. Third-party input to MISO and transmission owners is advisory only.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

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

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**EXHIBIT**

**OF**

**DANIEL S. ALFRED**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

| Line | Description | Source / Calculation | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Billing Determinants** | | | | | | | | | | | | | | |
| 1 | Peak MWs | Workpaper DSA-1 | 5,153 | 4,894 | 4,769 | 4,395 | 5,312 | 6,669 | 7,149 | 7,079 | 6,109 | 4,773 | 4,932 | 5,353 | **66,587** |
| 2 | Hours per Month | Day in Month * 24 | 744 | 696 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | **8,784** |
| 3 | Delivered MWhs | Workpaper DSA-3 | 3,161,262 | 2,879,458 | 2,895,806 | 2,663,683 | 2,768,857 | 3,038,520 | 3,397,863 | 3,293,338 | 2,859,540 | 2,750,093 | 2,788,990 | 3,049,013 | **35,546,425** |
| | **Rates** | | | | | | | | | | | | | | |
| 4 | Schedule 1 - System Control and Dispatch | Workpaper DSA-6 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | $ 83.4075 | |
| 5 | Schedule 2 - Reactive Support | Workpaper DSA-4 | 0 | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | Schedule 9 - Network Transmission Service | Workpaper DSA-5 | 6,213 | 6,213 | 6,213 | 6,213 | 6,213 | 6,314 | 6,314 | 6,314 | 6,314 | 6,314 | 6,314 | 6,314 | |
| 7 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Workpaper DSA-6 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | |
| 8 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Workpaper DSA-6 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | |
| 9 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Workpaper DSA-6 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | |
| 10 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Workpaper DSA-6 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | |
| 11 | Schedule 17 - ISO Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | |
| 12 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | |
| 13 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Workpaper DSA-5a | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | 1,161 | |
| 14 | Schedule 26-A - Multi-Value Project Usage Rate | Workpaper DSA-5a | 1.77 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | 1.7700 | |
| 15 | Schedule 33 - Blackstart Service | Workpaper DSA-5a | 4.37 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | 4.3749 | |
| 16 | Schedule 50 TOIF | Workpaper DSA-5a | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | 22.91 | |
| 17 | Schedule 49 Regional Directional Transfer Payments | Workpaper DSA-5a | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | 1.45 | |
| | **Expenses** | | | | | | | | | | | | | | |
| 18 | Schedule 1 - System Control and Dispatch | Line 1 * Line 4 | $ 429,832 | $ 408,174 | $ 397,741 | $ 366,597 | $ 443,066 | $ 556,238 | $ 596,249 | $ 590,420 | $ 509,555 | $ 398,131 | $ 411,392 | $ 446,440 | **$ 5,553,835** |
| 19 | Schedule 2 - Reactive Support | Line 1 * Line 5 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| 20 | Schedule 9 - Network Transmission Service | Line 1 * Line 6 | 32,019,392 | 30,405,990 | 29,628,807 | 27,308,850 | 33,005,253 | 42,110,108 | 45,139,220 | 44,697,898 | 38,575,979 | 30,140,585 | 31,144,561 | 33,797,874 | **417,974,515** |
| 21 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Line 1 * Line 2 * Line 7 | 243,084 | 215,943 | 224,935 | 200,635 | 250,568 | 304,423 | 337,198 | 333,901 | 278,874 | 225,156 | 225,150 | 252,476 | **3,092,342** |
| 22 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Line 3 * Line 8 | 327,823 | 298,600 | 300,295 | 276,224 | 287,130 | 315,094 | 352,358 | 341,519 | 296,534 | 285,185 | 289,218 | 316,183 | **3,686,164** |
| 23 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Line 3 * Line 9 | 349,320 | 318,180 | 319,987 | 294,337 | 305,959 | 335,756 | 375,464 | 363,914 | 315,979 | 303,885 | 308,183 | 336,916 | **3,927,880** |
| 24 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Line 1 * Line 2 * Line 10 | 16,870 | 14,987 | 15,611 | 13,924 | 17,390 | 21,127 | 23,402 | 23,173 | 19,354 | 15,626 | 15,626 | 17,522 | **214,610** |
| 25 | Schedule 17 - ISO Cost Adder - Energy Markets | (Line 3 * 2) * Line 11 | 584,834 | 532,700 | 535,724 | 492,781 | 512,239 | 562,126 | 628,605 | 609,268 | 529,015 | 508,767 | 515,963 | 564,067 | **6,576,089** |
| 26 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | (Line 3 * 2) * Line 12 | 72,709 | 66,228 | 66,604 | 61,265 | 63,684 | 69,886 | 78,151 | 75,747 | 65,769 | 63,252 | 64,147 | 70,127 | **817,568** |
| 27 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Line 1 * Line 13 | 5,982,661 | 5,681,205 | 5,535,993 | 5,102,520 | 6,166,864 | 7,742,048 | 8,298,958 | 8,217,819 | 7,092,289 | 5,541,421 | 5,726,005 | 6,213,823 | **77,301,607** |
| 28 | Schedule 26-A - Multi-Value Project Usage Rate | Line 3 * Line 14 | 5,595,435 | 5,096,641 | 5,125,577 | 4,714,719 | 4,900,877 | 5,378,180 | 6,014,218 | 5,829,209 | 5,061,386 | 4,867,665 | 4,936,512 | 5,396,753 | **62,917,172** |
| 29 | Schedule 33 - Blackstart Service | Line 1 * Line 15 | 22,545 | 21,409 | 20,862 | 19,229 | 23,240 | 29,176 | 31,274 | 30,968 | 26,727 | 20,883 | 21,578 | 23,417 | **291,308** |
| 30 | METC Agency Agreement | | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | **24,000** |
| 31 | Schedule 50 TOIF | Line 1 * Line 16 | 118,072 | 112,123 | 109,257 | 100,702 | 121,707 | 152,795 | 163,786 | 162,185 | 139,971 | 109,364 | 113,007 | 122,634 | **1,525,602** |
| 32 | Schedule 49 Regional Directional Transfer Payments | Line 1 * Line 17 | 7,462 | 7,086 | 6,905 | 6,364 | 7,691 | 9,656 | 10,351 | 10,249 | 8,846 | 6,911 | 7,142 | 7,750 | **96,412** |
| 33 | Total Transmission Expenses | **Lines 18-23 + 27-32** | **$ 45,097,625** | **$ 42,567,350** | **$ 41,672,358** | **$ 38,392,177** | **$ 45,514,357** | **$ 56,935,473** | **$ 61,321,076** | **$ 60,580,083** | **$ 52,308,140** | **$ 41,901,186** | **$ 43,184,748** | **$ 46,916,266** | $ 576,390,838 |
| 34 | Total Energy Market Administration Expenses | **Lines 24-26** | **674,413** | **613,914** | **617,938** | **567,970** | **593,312** | **653,139** | **730,157** | **708,187** | **614,138** | **587,645** | **595,735** | **651,717** | 7,608,267 |
| **35** | **Total Transmission and Energy Markets Administration Expenses** | **Lines 33 + 34** | **$ 45,772,038** | **$ 43,181,264** | **$ 42,290,296** | **$ 38,960,147** | **$ 46,107,669** | **$ 57,588,612** | **$ 62,051,233** | **$ 61,288,270** | **$ 52,922,279** | **$ 42,488,831** | **$ 43,780,484** | **$ 47,567,982** | **$ 583,999,104** |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
**2026 Transmission and Energy Market Administration Expenses**

Case No.: U-21592
Exhibit: A-1 (DSA-1)
Page: 2 of 5
Witness: DSAlfred
Date: September 2024

| Line | Description | Source / Calculation | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Billing Determinants** | | | | | | | | | | | | | | |
| 1 | Peak MWs | Workpaper DSA-1 | 5,232 | 5,017 | 4,871 | 4,620 | 5,557 | 6,814 | 7,254 | 7,180 | 6,269 | 4,977 | 5,056 | 5,499 | **68,346** |
| 2 | Hours per Month | Day in Month * 24 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | **8,760** |
| 3 | Delivered MWhs | Workpaper DSA-3 | 3,271,583 | 3,011,123 | 2,962,759 | 2,802,659 | 2,877,019 | 3,166,700 | 3,430,478 | 3,391,494 | 2,940,683 | 2,901,264 | 2,876,837 | 3,152,233 | **36,784,830** |
| | **Rates** | | | | | | | | | | | | | | |
| 4 | Schedule 1 - System Control and Dispatch | Workpaper DSA-6 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | |
| 5 | Schedule 2 - Reactive Support | Workpaper DSA-4 | 0 | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | Schedule 9 - Network Transmission Service | Workpaper DSA-5 | 6,391 | 6,391 | 6,391 | 6,391 | 6,391 | 6,395 | 6,395 | 6,395 | 6,395 | 6,395 | 6,395 | 6,395 | |
| 7 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Workpaper DSA-6 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | |
| 8 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Workpaper DSA-6 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | |
| 9 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Workpaper DSA-6 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | |
| 10 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Workpaper DSA-6 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | |
| 11 | Schedule 17 - ISO Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | |
| 12 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | |
| 13 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Workpaper DSA-5a | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | 1,187 | |
| 14 | Schedule 26-A - Multi-Value Project Usage Rate | Workpaper DSA-5a | 2 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | 2.0000 | |
| 15 | Schedule 33 - Blackstart Service | Workpaper DSA-5a | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | 4.2721 | |
| 16 | Schedule 50 TOIF | Workpaper DSA-5a | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | 22.3736 | |
| 17 | Schedule 49 Regional Directional Transfer Payments | Workpaper DSA-5a | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | 15.46 | |
| | **Expenses** | | | | | | | | | | | | | | |
| 18 | Schedule 1 - System Control and Dispatch | Line 1 * Line 4 | $ 451,104 | $ 432,559 | $ 419,965 | $ 398,362 | $ 479,097 | $ 587,473 | $ 625,449 | $ 619,094 | $ 540,560 | $ 429,147 | $ 435,929 | $ 474,131 | **$ 5,892,870** |
| 19 | Schedule 2 - Reactive Support | Line 1 * Line 5 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| 20 | Schedule 9 - Network Transmission Service | Line 1 * Line 6 | 33,439,661 | 32,064,970 | 31,131,425 | 29,530,024 | 35,514,755 | 43,572,223 | 46,388,864 | 45,917,548 | 40,092,725 | 31,829,362 | 32,332,344 | 35,165,795 | **436,979,696** |
| 21 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Line 1 * Line 2 * Line 7 | 246,790 | 213,743 | 229,754 | 210,906 | 262,104 | 311,027 | 342,171 | 338,694 | 286,190 | 234,778 | 230,795 | 259,388 | **3,166,338** |
| 22 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Line 3 * Line 8 | 339,263 | 312,253 | 307,238 | 290,636 | 298,347 | 328,387 | 355,741 | 351,698 | 304,949 | 300,861 | 298,328 | 326,887 | **3,814,587** |
| 23 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Line 3 * Line 9 | 361,510 | 332,729 | 327,385 | 309,694 | 317,911 | 349,920 | 379,068 | 374,760 | 324,946 | 320,590 | 317,890 | 348,322 | **4,064,724** |
| 24 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Line 1 * Line 2 * Line 10 | 17,127 | 14,834 | 15,945 | 14,637 | 18,190 | 21,585 | 23,747 | 23,506 | 19,862 | 16,294 | 16,017 | 18,002 | **219,746** |
| 25 | Schedule 17 - ISO Cost Adder - Energy Markets | (Line 3 * 2) * Line 11 | 605,243 | 557,058 | 548,110 | 518,492 | 532,249 | 585,840 | 634,638 | 627,426 | 544,026 | 536,734 | 532,215 | 583,163 | **6,805,194** |
| 26 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | (Line 3 * 2) * Line 12 | 75,246 | 69,256 | 68,143 | 64,461 | 66,171 | 72,834 | 78,901 | 78,004 | 67,636 | 66,729 | 66,167 | 72,501 | **846,051** |
| 27 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Line 1 * Line 13 | 6,208,356 | 5,953,133 | 5,779,813 | 5,482,499 | 6,593,615 | 8,085,155 | 8,607,804 | 8,520,348 | 7,439,508 | 5,906,179 | 5,999,511 | 6,525,279 | **81,101,199** |
| 28 | Schedule 26-A - Multi-Value Project Usage Rate | Line 3 * Line 14 | 6,543,166 | 6,022,245 | 5,925,518 | 5,605,317 | 5,754,038 | 6,333,401 | 6,860,955 | 6,782,987 | 5,881,367 | 5,802,528 | 5,753,673 | 6,304,465 | **73,569,661** |
| 29 | Schedule 33 - Blackstart Service | Line 1 * Line 15 | 22,352 | 21,433 | 20,809 | 19,738 | 23,739 | 29,109 | 30,990 | 30,675 | 26,784 | 21,264 | 21,600 | 23,493 | **291,986** |
| 30 | METC Agency Agreement | | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | **24,000** |
| 31 | Schedule 50 TOIF | Line 1 * Line 16 | 117,058 | 112,246 | 108,978 | 103,372 | 124,322 | 152,445 | 162,299 | 160,650 | 140,271 | 111,360 | 113,120 | 123,033 | **1,529,153** |
| 32 | Schedule 49 Regional Directional Transfer Payments | Line 1 * Line 17 | 80,895 | 77,570 | 75,311 | 71,437 | 85,915 | 105,350 | 112,160 | 111,020 | 96,937 | 76,958 | 78,174 | 85,025 | **1,056,752** |
| 33 | Total Transmission Expenses | **Lines 18-23 + 27-32** | **$ 47,812,153** | **$ 45,544,881** | **$ 44,328,196** | **$ 42,023,985** | **$ 49,455,842** | **$ 59,856,489** | **$ 63,867,501** | **$ 63,209,476** | **$ 55,136,236** | **$ 45,035,026** | **$ 45,583,363** | **$49,637,816** | **$ 611,490,966** |
| 34 | Total Energy Market Administration Expenses | **Lines 24-26** | **697,617** | **641,147** | **632,199** | **597,590** | **616,610** | **680,259** | **737,286** | **728,936** | **631,524** | **619,757** | **614,399** | **673,666** | **7,870,991** |
| **35** | **Total Transmission and Energy Markets Administration Expenses** | **Lines 33 + 34** | **$ 48,509,770** | **$ 46,186,029** | **$ 44,960,395** | **$ 42,621,575** | **$ 50,072,452** | **$ 60,536,748** | **$ 64,604,787** | **$ 63,938,413** | **$ 55,767,760** | **$ 45,654,782** | **$ 46,197,763** | **$50,311,482** | **$ 619,361,956** |

| Line | Description | Source / Calculation | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Billing Determinants** | | | | | | | | | | | | | | |
| 1 | Peak MWs | Workpaper DSA-1 | 5,366 | 5,179 | 5,054 | 4,793 | 5,740 | 7,021 | 7,442 | 7,372 | 6,462 | 5,164 | 5,252 | 5,711 | **70,554** |
| 2 | Hours per Month | Day in Month * 24 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | **8,760** |
| 3 | Delivered MWhs | Workpaper DSA-3 | 3,392,333 | 3,036,719 | 3,032,830 | 2,901,456 | 2,969,202 | 3,308,801 | 3,594,017 | 3,548,826 | 3,100,861 | 3,003,613 | 2,997,656 | 3,330,920 | **38,217,235** |
| | **Rates** | | | | | | | | | | | | | | |
| 4 | Schedule 1 - System Control and Dispatch | Workpaper DSA-6 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | |
| 5 | Schedule 2 - Reactive Support | Workpaper DSA-4 | 0 | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | Schedule 9 - Network Transmission Service | Workpaper DSA-5 | 6,523 | 6,523 | 6,523 | 6,523 | 6,523 | 6,497 | 6,497 | 6,497 | 6,497 | 6,497 | 6,497 | 6,497 | |
| 7 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Workpaper DSA-6 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | |
| 8 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Workpaper DSA-6 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | |
| 9 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Workpaper DSA-6 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | |
| 10 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Workpaper DSA-6 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | |
| 11 | Schedule 17 - ISO Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | |
| 12 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | |
| 13 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Workpaper DSA-5a | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | 1,203 | |
| 14 | Schedule 26-A - Multi-Value Project Usage Rate | Workpaper DSA-5a | 2.3 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | 2.3000 | |
| 15 | Schedule 33 - Blackstart Service | Workpaper DSA-5a | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | 4.1539 | |
| 16 | Schedule 50 TOIF | Workpaper DSA-5a | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | 21.7543 | |
| 17 | Schedule 49 Regional Directional Transfer Payments | Workpaper DSA-5a | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | 15.03 | |
| | **Expenses** | | | | | | | | | | | | | | |
| 18 | Schedule 1 - System Control and Dispatch | Line 1 * Line 4 | $ 462,622 | $ 446,528 | $ 435,743 | $ 413,216 | $ 494,944 | $ 605,317 | $ 641,652 | $ 635,594 | $ 557,129 | $ 445,282 | $ 452,822 | $ 492,381 | **$ 6,083,231** |
| 19 | Schedule 2 - Reactive Support | Line 1 * Line 5 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| 20 | Schedule 9 - Network Transmission Service | Line 1 * Line 6 | 34,998,599 | 33,781,037 | 32,965,131 | 31,260,888 | 37,443,823 | 45,615,162 | 48,353,307 | 47,896,809 | 41,983,869 | 33,555,347 | 34,123,583 | 37,104,650 | **459,082,204** |
| 21 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Line 1 * Line 2 * Line 7 | 253,091 | 220,646 | 238,386 | 218,770 | 270,774 | 320,474 | 351,035 | 347,721 | 294,962 | 243,605 | 239,739 | 269,372 | **3,268,574** |
| 22 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Line 3 * Line 8 | 351,785 | 314,908 | 314,504 | 300,881 | 307,906 | 343,123 | 372,700 | 368,013 | 321,559 | 311,475 | 310,857 | 345,416 | **3,963,127** |
| 23 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Line 3 * Line 9 | 374,853 | 335,557 | 335,128 | 320,611 | 328,097 | 365,622 | 397,139 | 392,145 | 342,645 | 331,899 | 331,241 | 368,067 | **4,223,004** |
| 24 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Line 1 * Line 2 * Line 10 | 17,565 | 15,313 | 16,544 | 15,183 | 18,792 | 22,241 | 24,362 | 24,132 | 20,471 | 16,906 | 16,638 | 18,695 | **226,841** |
| 25 | Schedule 17 - ISO Cost Adder - Energy Markets | (Line 3 * 2) * Line 11 | 627,582 | 561,793 | 561,074 | 536,769 | 549,302 | 612,128 | 664,893 | 656,533 | 573,659 | 555,668 | 554,566 | 616,220 | **7,070,188** |
| 26 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | (Line 3 * 2) * Line 12 | 78,024 | 69,845 | 69,755 | 66,733 | 68,292 | 76,102 | 82,662 | 81,623 | 71,320 | 69,083 | 68,946 | 76,611 | **878,996** |
| 27 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Line 1 * Line 13 | 6,452,453 | 6,227,980 | 6,077,557 | 5,763,357 | 6,903,263 | 8,442,691 | 8,949,481 | 8,864,990 | 7,770,593 | 6,210,598 | 6,315,770 | 6,867,521 | **84,846,255** |
| 28 | Schedule 26-A - Multi-Value Project Usage Rate | Line 3 * Line 14 | 7,802,366 | 6,984,453 | 6,975,509 | 6,673,350 | 6,829,165 | 7,610,242 | 8,266,240 | 8,162,300 | 7,131,980 | 6,908,309 | 6,894,609 | 7,661,117 | **87,899,639** |
| 29 | Schedule 33 - Blackstart Service | Line 1 * Line 15 | 22,288 | 21,513 | 20,993 | 19,908 | 23,845 | 29,163 | 30,913 | 30,621 | 26,841 | 21,453 | 21,816 | 23,722 | **293,074** |
| 30 | METC Agency Agreement | | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | **24,000** |
| 31 | Schedule 50 TOIF | Line 1 * Line 16 | 116,724 | 112,663 | 109,942 | 104,258 | 124,879 | 152,727 | 161,895 | 160,366 | 140,569 | 112,349 | 114,251 | 124,232 | **1,534,855** |
| 32 | Schedule 49 Regional Directional Transfer Payments | Line 1 * Line 17 | 80,664 | 77,858 | 75,978 | 72,050 | 86,300 | 105,545 | 111,881 | 110,824 | 97,143 | 77,641 | 78,956 | 85,853 | **1,060,693** |
| 33 | Total Transmission Expenses | **Lines 18-23 + 27-32** | **$ 50,917,445** | **$ 48,525,143** | **$ 47,550,870** | **$ 45,149,288** | **$ 52,814,995** | **$ 63,592,066** | **$ 67,638,242** | **$ 66,971,385** | **$ 58,669,290** | **$ 48,219,956** | **$ 48,885,644** | **$53,344,332** | **$ 652,278,657** |
| 34 | Total Energy Market Administration Expenses | **Lines 24-26** | **723,170** | **646,950** | **647,373** | **618,686** | **636,386** | **710,472** | **771,918** | **762,288** | **665,450** | **641,658** | **640,151** | **711,526** | **8,176,026** |
| **35** | **Total Transmission and Energy Markets Administration Expenses** | **Lines 33 + 34** | **$ 51,640,615** | **$ 49,172,093** | **$ 48,198,243** | **$ 45,767,974** | **$ 53,451,381** | **$ 64,302,538** | **$ 68,410,160** | **$ 67,733,673** | **$ 59,334,739** | **$ 48,861,614** | **$ 49,525,794** | **$54,055,858** | **$ 660,454,683** |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
**2028 Transmission and Energy Market Administration Expenses**

Case No.: U-21592
Exhibit: A-1 (DSA-1)
Page: 4 of 5
Witness: DSAlfred
Date: September 2024

| Line | Description | Source / Calculation | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Billing Determinants** | | | | | | | | | | | | | | |
| 1 | Peak MWs | Workpaper DSA-1 | 5,509 | 5,567 | 5,229 | 4,872 | 5,783 | 7,153 | 7,491 | 7,312 | 6,524 | 5,228 | 5,305 | 5,683 | **71,656** |
| 2 | Hours per Month | Day in Month * 24 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | **8,760** |
| 3 | Delivered MWhs | Workpaper DSA-3 | 3,502,130 | 3,148,862 | 3,136,457 | 2,988,352 | 3,017,233 | 3,328,825 | 3,699,542 | 3,599,114 | 3,137,898 | 3,026,285 | 3,025,768 | 3,267,115 | **38,877,581** |
| | **Rates** | | | | | | | | | | | | | | |
| 4 | Schedule 1 - System Control and Dispatch | Workpaper DSA-6 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | |
| 5 | Schedule 2 - Reactive Support | Workpaper DSA-4 | 0 | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | Schedule 9 - Network Transmission Service | Workpaper DSA-5 | 6,680 | 6,680 | 6,680 | 6,680 | 6,680 | 6,770 | 6,770 | 6,770 | 6,770 | 6,770 | 6,770 | 6,770 | |
| 7 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Workpaper DSA-6 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | |
| 8 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Workpaper DSA-6 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | |
| 9 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Workpaper DSA-6 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | |
| 10 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Workpaper DSA-6 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | |
| 11 | Schedule 17 - ISO Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | |
| 12 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | |
| 13 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Workpaper DSA-5a | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | |
| 14 | Schedule 26-A - Multi-Value Project Usage Rate | Workpaper DSA-5a | 2.64 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | 2.6400 | |
| 15 | Schedule 33 - Blackstart Service | Workpaper DSA-5a | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | 4.0957 | |
| 16 | Schedule 50 TOIF | Workpaper DSA-5a | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | 21.4496 | |
| 17 | Schedule 49 Regional Directional Transfer Payments | Workpaper DSA-5a | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | 14.82 | |
| | **Expenses** | | | | | | | | | | | | | | |
| 18 | Schedule 1 - System Control and Dispatch | Line 1 * Line 4 | $ 475,007 | $ 479,979 | $ 450,874 | $ 420,072 | $ 498,632 | $ 616,762 | $ 645,882 | $ 630,403 | $ 562,537 | $ 450,746 | $ 457,374 | $ 489,979 | **$ 6,178,245** |
| 19 | Schedule 2 - Reactive Support | Line 1 * Line 5 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| 20 | Schedule 9 - Network Transmission Service | Line 1 * Line 6 | 36,800,927 | 37,186,148 | 34,931,269 | 32,544,886 | 38,631,255 | 48,428,084 | 50,714,562 | 49,499,155 | 44,170,321 | 35,392,542 | 35,912,928 | 38,473,119 | **482,685,195** |
| 21 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Line 1 * Line 2 * Line 7 | 259,867 | 237,175 | 246,664 | 222,400 | 272,791 | 326,534 | 353,349 | 344,881 | 297,825 | 246,594 | 242,148 | 268,058 | **3,318,284** |
| 22 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Line 3 * Line 8 | 363,171 | 326,537 | 325,251 | 309,892 | 312,887 | 345,199 | 383,643 | 373,228 | 325,400 | 313,826 | 313,772 | 338,800 | **4,031,605** |
| 23 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Line 3 * Line 9 | 386,985 | 347,949 | 346,579 | 330,213 | 333,404 | 367,835 | 408,799 | 397,702 | 346,738 | 334,404 | 334,347 | 361,016 | **4,295,973** |
| 24 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Line 1 * Line 2 * Line 10 | 18,035 | 16,460 | 17,119 | 15,435 | 18,932 | 22,662 | 24,523 | 23,935 | 20,669 | 17,114 | 16,805 | 18,603 | **230,291** |
| 25 | Schedule 17 - ISO Cost Adder - Energy Markets | (Line 3 * 2) * Line 11 | 647,894 | 582,540 | 580,245 | 552,845 | 558,188 | 615,833 | 684,415 | 665,836 | 580,511 | 559,863 | 559,767 | 604,416 | **7,192,353** |
| 26 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | (Line 3 * 2) * Line 12 | 80,549 | 72,424 | 72,139 | 68,732 | 69,396 | 76,563 | 85,089 | 82,780 | 72,172 | 69,605 | 69,593 | 75,144 | **894,184** |
| 27 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Line 1 * Line 13 | 6,621,320 | 6,690,630 | 6,284,926 | 5,855,562 | 6,950,638 | 8,597,309 | 9,003,221 | 8,787,453 | 7,841,439 | 6,283,144 | 6,375,526 | 6,830,030 | **86,121,199** |
| 28 | Schedule 26-A - Multi-Value Project Usage Rate | Line 3 * Line 14 | 9,245,624 | 8,312,996 | 8,280,247 | 7,889,249 | 7,965,495 | 8,788,097 | 9,766,791 | 9,501,661 | 8,284,051 | 7,989,392 | 7,988,027 | 8,625,183 | **102,636,815** |
| 29 | Schedule 33 - Blackstart Service | Line 1 * Line 15 | 22,564 | 22,800 | 21,418 | 19,955 | 23,686 | 29,298 | 30,681 | 29,946 | 26,722 | 21,412 | 21,726 | 23,275 | **293,483** |
| 30 | METC Agency Agreement | | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | **24,000** |
| 31 | Schedule 50 TOIF | Line 1 * Line 16 | 118,170 | 119,407 | 112,166 | 104,504 | 124,047 | 153,435 | 160,679 | 156,829 | 139,945 | 112,135 | 113,783 | 121,895 | **1,536,995** |
| 32 | Schedule 49 Regional Directional Transfer Payments | Line 1 * Line 17 | 81,664 | 82,519 | 77,515 | 72,219 | 85,725 | 106,034 | 111,041 | 108,380 | 96,712 | 77,493 | 78,632 | 84,238 | **1,062,171** |
| 33 | Total Transmission Expenses | **Lines 18-23 + 27-32** | **$ 54,377,299** | **$ 53,808,140** | **$ 51,078,909** | **$ 47,770,950** | **$ 55,200,561** | **$ 67,760,588** | **$ 71,580,647** | **$ 69,831,637** | **$ 62,093,689** | **$ 51,223,687** | **$ 51,840,265** | **$55,617,593** | $ 692,183,965 |
| 34 | Total Energy Market Administration Expenses | **Lines 24-26** | **746,478** | **671,423** | **669,502** | **637,012** | **646,516** | **715,057** | **794,027** | **772,551** | **673,352** | **646,581** | **646,165** | **698,163** | 8,316,828 |
| **35** | **Total Transmission and Energy Markets Administration Expenses** | **Lines 33 + 34** | **$ 55,123,777** | **$ 54,479,564** | **$ 51,748,411** | **$ 48,407,962** | **$ 55,847,077** | **$ 68,475,645** | **$ 72,374,675** | **$ 70,604,188** | **$ 62,767,041** | **$ 51,870,268** | **$ 52,486,430** | **$56,315,756** | $ 700,500,793 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
**2029 Transmission and Energy Market Administration Expenses** Adan's looks

Case No.: U-21592
Exhibit: A-1 (DSA-1)
Page: 5 of 5
Witness: DSAlfred
Date: September 2024

| Line | Description | Source / Calculation | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | TOTAL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Billing Determinants** | | | | | | | | | | | | | | |
| 1 | Peak MWs | Workpaper DSA-1 | 5,564 | 5,587 | 5,371 | 5,091 | 6,094 | 7,378 | 7,533 | 7,521 | 7,059 | 5,489 | 5,654 | 6,114 | **74,457** |
| 2 | Hours per Month | Day in Month * 24 | 744 | 672 | 744 | 720 | 744 | 720 | 744 | 744 | 720 | 744 | 720 | 744 | **8,760** |
| 3 | Delivered MWhs | Workpaper DSA-3 | 3,566,054 | 3,220,044 | 3,213,598 | 3,142,538 | 3,161,703 | 3,461,406 | 3,863,195 | 3,743,866 | 3,336,466 | 3,132,976 | 3,184,121 | 3,457,292 | **40,483,259** |
| | **Rates** | | | | | | | | | | | | | | |
| 4 | Schedule 1 - System Control and Dispatch | Workpaper DSA-6 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | $ 86.2207 | |
| 5 | Schedule 2 - Reactive Support | Workpaper DSA-4 | 0 | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | Schedule 9 - Network Transmission Service | Workpaper DSA-5 | 6,824 | 6,824 | 6,824 | 6,824 | 6,824 | 6,737 | 6,737 | 6,737 | 6,737 | 6,737 | 6,737 | 6,737 | |
| 7 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Workpaper DSA-6 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | 0.0634 | |
| 8 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Workpaper DSA-6 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | 0.1037 | |
| 9 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Workpaper DSA-6 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | 0.1105 | |
| 10 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Workpaper DSA-6 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | 0.0044 | |
| 11 | Schedule 17 - ISO Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | 0.0925 | |
| 12 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | Workpaper DSA-6 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | 0.0115 | |
| 13 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Workpaper DSA-5a | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | 1,202 | |
| 14 | Schedule 26-A - Multi-Value Project Usage Rate | Workpaper DSA-5a | 3.18 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | 3.1800 | |
| 15 | Schedule 33 - Blackstart Service | Workpaper DSA-5a | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | 3.9597 | |
| 16 | Schedule 50 TOIF | Workpaper DSA-5a | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | 20.7372 | |
| 17 | Schedule 49 Regional Directional Transfer Payments | Workpaper DSA-5a | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | 14.33 | |
| | **Expenses** | | | | | | | | | | | | | | |
| 18 | Schedule 1 - System Control and Dispatch | Line 1 * Line 4 | $ 479,773 | $ 481,751 | $ 463,114 | $ 438,941 | $ 525,407 | $ 636,144 | $ 649,486 | $ 648,459 | $ 608,658 | $ 473,299 | $ 487,522 | $ 527,171 | **$ 6,419,725** |
| 19 | Schedule 2 - Reactive Support | Line 1 * Line 5 | - | - | - | - | - | - | - | - | - | - | - | - | **-** |
| 20 | Schedule 9 - Network Transmission Service | Line 1 * Line 6 | 37,969,896 | 38,126,369 | 36,651,436 | 34,738,356 | 41,581,416 | 49,706,415 | 50,748,902 | 50,668,675 | 47,558,723 | 36,982,213 | 38,093,551 | 41,191,588 | **504,017,540** |
| 21 | Schedule 10 - ISO Cost Recovery Adder - Demand Basis | Line 1 * Line 2 * Line 7 | 262,474 | 238,051 | 253,360 | 232,389 | 287,440 | 336,795 | 355,320 | 354,759 | 322,243 | 258,932 | 258,110 | 288,405 | **3,448,278** |
| 22 | Schedule 10 - ISO Cost Recovery Adder - Energy Basis | Line 3 * Line 8 | 369,800 | 333,919 | 333,250 | 325,881 | 327,869 | 358,948 | 400,613 | 388,239 | 345,992 | 324,890 | 330,193 | 358,521 | **4,198,114** |
| 23 | Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge | Line 3 * Line 9 | 394,049 | 355,815 | 355,103 | 347,250 | 349,368 | 382,485 | 426,883 | 413,697 | 368,680 | 346,194 | 351,845 | 382,031 | **4,473,400** |
| 24 | Schedule 16 - ISO Cost Adder - Financial Transmission Rights | Line 1 * Line 2 * Line 10 | 18,216 | 16,521 | 17,583 | 16,128 | 19,948 | 23,374 | 24,659 | 24,620 | 22,364 | 17,970 | 17,913 | 20,015 | **239,313** |
| 25 | Schedule 17 - ISO Cost Adder - Energy Markets | (Line 3 * 2) * Line 11 | 659,720 | 595,708 | 594,516 | 581,369 | 584,915 | 640,360 | 714,691 | 692,615 | 617,246 | 579,601 | 589,062 | 639,599 | **7,489,403** |
| 26 | Schedule 24 - Balancing Area Cost Adder - Energy Markets | (Line 3 * 2) * Line 12 | 82,019 | 74,061 | 73,913 | 72,278 | 72,719 | 79,612 | 88,853 | 86,109 | 76,739 | 72,058 | 73,235 | 79,518 | **931,115** |
| 27 | Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan | Line 1 * Line 13 | 6,687,767 | 6,715,327 | 6,455,542 | 6,118,585 | 7,323,876 | 8,867,482 | 9,053,458 | 9,039,146 | 8,484,340 | 6,597,520 | 6,795,780 | 7,348,461 | **89,487,284** |
| 28 | Schedule 26-A - Multi-Value Project Usage Rate | Line 3 * Line 14 | 11,340,051 | 10,239,741 | 10,219,242 | 9,993,269 | 10,054,216 | 11,007,270 | 12,284,959 | 11,905,494 | 10,609,962 | 9,962,864 | 10,125,505 | 10,994,189 | **128,736,763** |
| 29 | Schedule 33 - Blackstart Service | Line 1 * Line 15 | 22,034 | 22,124 | 21,269 | 20,158 | 24,129 | 29,215 | 29,828 | 29,781 | 27,953 | 21,736 | 22,389 | 24,210 | **294,826** |
| 30 | METC Agency Agreement | | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | 2,000 | **24,000** |
| 31 | Schedule 50 TOIF | Line 1 * Line 16 | 115,392 | 115,867 | 111,385 | 105,571 | 126,368 | 153,001 | 156,210 | 155,963 | 146,390 | 113,835 | 117,256 | 126,792 | **1,544,030** |
| 32 | Schedule 49 Regional Directional Transfer Payments | Line 1 * Line 17 | 79,744 | 80,073 | 76,975 | 72,957 | 87,329 | 105,735 | 107,952 | 107,781 | 101,166 | 78,668 | 81,032 | 87,622 | **1,067,033** |
| 33 | Total Transmission Expenses | **Lines 18-23 + 27-32** | **$ 57,722,979** | **$56,711,037** | **$ 54,942,676** | **$ 52,395,358** | **$ 60,689,417** | **$ 71,585,490** | **$ 74,215,612** | **$ 73,713,993** | **$ 68,576,106** | **$ 55,162,152** | **$ 56,665,184** | **$ 61,330,990** | **$ 743,710,993** |
| 34 | Total Energy Market Administration Expenses | **Lines 24-26** | **759,955** | **686,290** | **686,012** | **669,776** | **677,583** | **743,346** | **828,204** | **803,345** | **716,349** | **669,629** | **680,210** | **739,132** | **8,659,831** |
| 35 | **Total Transmission and Energy Markets Administration Expenses** | **Lines 33 + 34** | **$ 58,482,934** | **$57,397,327** | **$ 55,628,687** | **$ 53,065,134** | **$ 61,367,000** | **$ 72,328,836** | **$ 75,043,816** | **$ 74,517,338** | **$ 69,292,455** | **$ 55,831,781** | **$ 57,345,394** | **$ 62,070,122** | **$ 752,370,824** |

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<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**DIRECT TESTIMONY**

**OF**

**EUGÈNE M.J.A. BREURING**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Eugène M.J.A. Breuring, 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 a Principal Sales Forecasting Analyst in the Financial Planning & Analysis Department.

**Q. Please describe your qualifications.**

A. In 1992, I graduated from Grand Valley State University with a Bachelor of Business Administration degree in Accounting. In 1996, I graduated from Thunderbird School of Global Management with a Master of Business Administration degree in International Management. I have also attended trade-specific conferences and seminars related to Michigan and United States economies, Michigan economic forecasts, as well as regression modeling.

Prior to joining Consumers Energy in 2013, I worked at the Kellogg Company, Tecumseh Products Company, and Stryker Corporation, mostly in a financial planning, budgeting, and forecasting capacity. In January 2013, I accepted the position of Senior Rate Analyst II. In 2020, I was promoted to Senior Analyst III, and again in 2023 to Principal Sales Forecasting Analyst, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's official electric deliveries and customer forecasts, sponsoring the deliveries and customer forecast testimony and exhibits, industry research, and various economic studies. Also, I am responsible for creating the Company's revenue forecast related to the electric business.

**Q. Have you sponsored testimony in any previous cases before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes, I have presented the Company's electric sales and revenues forecasts in the following cases:

| | |
|---|---|
| U-17771 | 2016 – 2017 Energy Optimization Plan and 2017 Amended Energy Waste Reduction ("EWR") Plan; |
| U-17990 | General Electric Rate Case; |
| U-18142 | 2017 Power Supply Cost Recovery ("PSCR") Plan; |
| U-18231 | 2017 Biennial Renewable Energy Plan; |
| U-18261 | 2018-2021 EWR Plan; |
| U-18322 | General Electric Rate Case; |
| U-18402 | 2018 PSCR Plan; |
| U-20134 | General Electric Rate Case; |
| U-20165 | 2018 Integrated Resource Plan ("IRP"); |
| U-20219 | 2019 PSCR Plan; |
| U-20372 | 2019 EWR Electric and Gas Biennial Plan; |
| U-20525 | 2020 PSCR Plan; |
| U-20697 | General Electric Rate Case; |
| U-20802 | 2021 PSCR Plan; |
| U-20875 | 2022-2025 EWR Plan; |
| U-20963 | General Electric Rate Case; |
| U-21048 | 2022 PSCR Plan; |
| U-21090 | 2021 IRP; |
| U-21224 | General Electric Rate Case; |

| | |
|---|---|
| U-21257 | 2023 PSCR Plan; |
| U-21321 | 2024-2025 EWR Plan; |
| U-21389 | General Electric Rate Case; |
| U-21423 | 2024 PSCR Plan; and |
| U-21585 | General Electric Rate Case. |

**Q. Please explain the purpose of your direct testimony in this proceeding.**

A. The purpose of my direct testimony is to present the Company's electric deliveries, generation requirements, and peak demand forecasts for the years 2025 to 2029, in support of the Company's 2025 PSCR Plan.

**Q. Are you sponsoring any exhibits in this case?**

A. Yes. I am providing the following exhibits:

| Exhibits | Description |
|---|---|
| A-2 (EMB-1) | 2025 Forecast of Calendar Total Electric Deliveries; |
| A-3 (EMB-2) | Forecast of Annual Calendar Deliveries; |
| A-4 (EMB-3) | Forecast of Total Monthly Generation Requirements; |
| A-5 (EMB-4) | Forecast of Total Monthly Peak Demand; and |
| A-6 (EMB-5) | Forecasted System Load Factor Based on Summer Peak Demand. |

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

A. Yes.

## SECTION I. FORECASTING METHODOLOGY

**Q. What is forecasting?**

A. Forecasting is predicting the future values of data. For purposes of this direct testimony, the Company will forecast electric deliveries and peak demand for the Company's electric service territory.

**Q. Are there different types of analyses used in preparing forecasts?**

A. Yes.

**Q. What type of analysis was utilized for forecasting electric deliveries and peak demand for the Company's electric service territory?**

A. Statistical modeling, or a regression analysis to forecast electric deliveries and peak demand for the Company's electric service territory was used.

**Q. Please briefly describe the process used to prepare the electric deliveries and peak demand forecasts.**

A. The electric deliveries and peak demand forecasts are prepared using a combination of econometric and end-use techniques.

**Q. What process is involved in developing the electric deliveries forecast?**

A. Typically, a six-step process is used in developing the electric deliveries forecast. The first step in the process is gathering the class-level historical monthly electric delivery, monthly customer counts, monthly number of billing days, monthly binaries to account for seasonal variation, and daily temperature information. Most observations are entered directly into the modeling framework as dependent and explanatory variables. The daily temperature information, however, is transformed to monthly heating degree days ("HDD") and cooling degree days ("CDD") variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from S&P Global (formerly, IHS Markit) into the sales modeling framework. These variables cover historical data going back to 2001, the start of the time horizon within the regression modeling process, as well as projections to the test year. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, Distributed Generation ("DG"), and energy savings from the Company's EWR programs. These forecasts are exogenous to the modeling framework and were either adopted by the Commission in prior electric rate cases, reflect current industry expectations, or are based on end-use analyses. The fourth step is reviewing the imported observations to identify data issues before running the econometric models. In situations when erroneous data is observed, it is either corrected where possible or removed from the models. The fifth step is executing the regression functions and reviewing the corresponding statistical metrics. The final step in the sales forecasting process is to combine the regression forecasts with the external forecasts imported in step three.

**Q. What is the process involved in developing the electric peak demand forecast?**

A. The peak demand forecast process is like that of the electric delivery forecast. The first step in the peak demand forecast is importing the Company's monthly system peak demands, corresponding minimum and maximum daily temperature, forecasted base electric deliveries, seasonal binaries, and number of customers into the demand modeling framework. An average of the minimum and maximum temperatures is used to develop the peak CDD and HDD variables prior to importing into the model framework. The second step is reviewing the imported observations to identify data issues before executing the peak demand econometric model. The third step is regressing the observed peak demands against the seasonal binary, degree day, and forecasted base electric sales.

The final step in the peak demand forecasting process is combining the results of the econometric model with the Company's projected peak demand adjustments, which consist of the following: (1) EWR; (2) Dynamic Peak Pricing ("DPP") programs; (3) Conservation Voltage Reduction ("CVR"); (4) Large Industrial Customers; and (5) Residential Summer On-Peak rate ("RSP").

**Q. In utilizing the regression models, what evaluation process is followed to ensure that the models' results are satisfactory?**

A. Regression modeling is used to develop the electric deliveries and customer count forecast models based on weather and economic variables. Each model is selected based on its ability to properly explain variation in historical data – i.e., how well it fits the data – along with the statistical significance of the model coefficients. Particularly, regression model performance is evaluated based on the adjusted coefficient of multiple determination ("$R_a^2$") and Mean Absolute Percent Error ("MAPE").

**Q. Please explain the use of $R_a^2$ and MAPE.**

A. Both statistical tests are used to evaluate how well the models fit the historical data and provide a good indication of how well the models will perform in the forecast period. The $R_a^2$ measures the ability of the models to explain variations in the historical data. An $R_a^2$ of unity suggests that a model explains all the variations in the data whereas an $R_a^2$ of zero suggests it explains none of the variations. For example, if regression models have $R_a^2$ values above 0.9, this suggests that at least 90% of the variation in the data is explained by the models. In most cases, the models used in the Company's forecasting process have values between 0.90 and 0.97. In addition, to gauge overall model performance, the MAPE values are considered. Essentially, the MAPE is used to measure the model errors in which smaller values suggest better model performance. MAPE values of less than 3% are generally considered ideal, although higher values may also be deemed acceptable based on other considerations, such as the $R_a^2$. The regression models used in the Company's forecasting process generally have MAPE values between 0.2% and 2.1%.

**Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.**

A. Regression analysis is used to develop models that minimize the variance between the actual data and estimates from the models based on the relationship between dependent and independent variables. A numerical coefficient ("$\beta$") is estimated for each independent variable in the model and represents the best linear unbiased estimate for that variable's contribution toward explaining the dependent variable. The t-statistics and p-values are used to gauge the relevance of each independent variable in the model. The t-statistic and p-values measure the statistical significance of including a particular independent variable based on a probability distribution. A t-statistic above two and p-value below 5% for a particular $\beta$ suggests the independent variable is statistically significant and is appropriate to include in the regression model. Independent variables with t-statistics below two and p-values above 5% suggest the variable should be excluded from the model since it does little to explain the dependent variable. In addition, the direction (positive or negative coefficient sign) and magnitude of each coefficient are also considered when determining to include or exclude variables from the models. The models' independent variable t-statistics and p-values are within these ranges and are, therefore, considered relevant.

**Q. What software is used to create these regression models for the energy, demand, and customer count projections? And why?**

A. For at least the last 15 years, the Company has utilized MetrixND for its regression modeling. MetrixND is a software package that is licensed by Itron, Ltd., a global technology company that provides technology and professional services to utilities to aid in their sales forecasting needs. Furthermore, MetrixND is considered an industry standard, as more than 150 utilities, Independent System Operators (ISOs), municipals, cooperatives and other energy service providers use Itron's MetrixND.[1]

## SECTION II. KEY ELECTRIC DELIVERY AND DEMAND VARIABLES

**Q. What are the key variables that affect the electric deliveries and demand forecasts?**

A. The key variables affecting the forecasts are weather, the economy, and demographics.

**Q. Please describe the impact of weather on the forecasting process and the assumptions you made regarding weather variables in the forecast.**

A. Weather is the primary variable used in the forecasting models to capture the seasonal variation in deliveries and demand across the year. This is accomplished using a 15-year average of HDD and CDD in the econometric models.

**Q. What are econometrics or econometric techniques?**

A. These are quantitative economic statistical techniques or tools that model the economy using mathematical and statistical relationships. A basic tool for econometrics is the regression model, as discussed elsewhere in my testimony.

[1] https://na.itron.com/o/commerce-media/accounts/-1/attachments/3828543

**Q. Please describe the impact of the economy on the forecasting process and the assumptions you made regarding these variables in the forecast.**

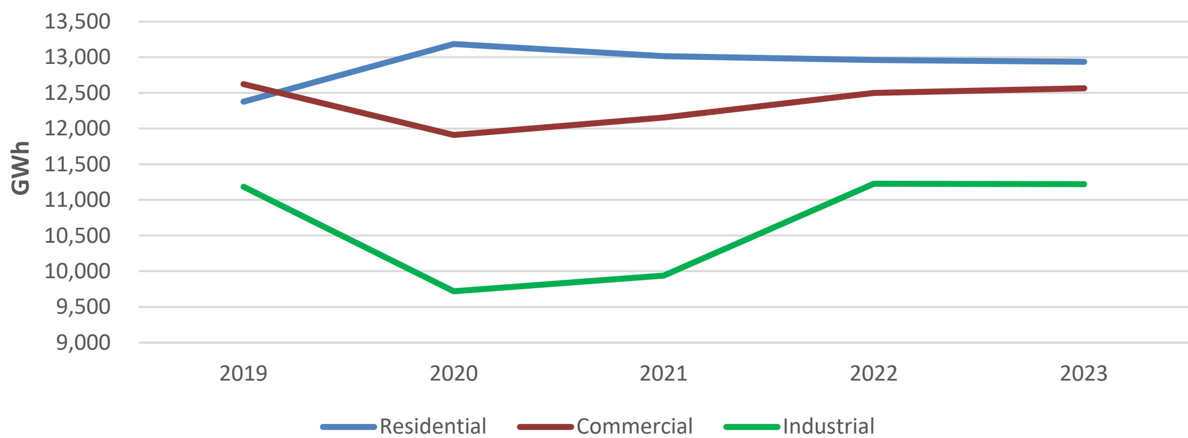
A. The Company uses economic indicators to capture the growth expectations related to increased or decreased economic activity in its service territory. Primarily, this includes employment and industrial production forecasts provided by S&P Global, a leading publishing company that provides industry-specific data and analysis.

## SECTION III. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

**Q. Please explain the Company's historical levels of electric deliveries for the five-year period from 2019 to 2023.**

A. In the past five years, weather-normalized electric deliveries increased at a 0.3% Compound Annual Growth Rate ("CAGR") from 2019 to 2023, with a marginal loss in the commercial class (-0.1%), and gains by the industrial class (0.1%) and the residential class (1.1%). These changes are graphically depicted in Figure 1.

Figure 1 - Historical Electric Cycle-billed, Weather-adjusted Deliveries by Class



**Q. What is the cause of the sudden Residential increase and Commercial/Industrial ("C&I") decrease of the 2020 weather-normalized deliveries, as shown in Figure 1?**

A. Following 2019, the Company's deliveries were impacted by the COVID-19 virus and the resulting pandemic. In 2020, the pandemic caused significant customer behavioral changes, such as an increase in remote working and temporary cessations or reductions in in-person operations for some C&I customers.

**Q. How did COVID-19 impact the different customer classes?**

A. COVID-19 and the ensuing pandemic had an inverse effect on the Company's residential and C&I customer classes. In 2020, the residential deliveries increased 6.5% over 2019 on a weather-adjusted basis. Conversely, weather-adjusted C&I deliveries decreased by 5.7% and 13.1%, respectively.

In 2020, executive orders from the Governor's office and other public health organization orders were issued to mitigate the spread of COVID-19. These orders encouraged Michiganders to stay at home and limit large social gatherings, pushing electric deliveries away from C&I and more toward the residential class. The "Stay at Home" order was in effect from March 24 until May 15, 2020. In addition to the residential and commercial customer classes, the industrial customer class was directly impacted due to the closures of the "Big Three" auto manufacturers in the middle of March 2020. In 2021, each customer class showed a trend toward pre-pandemic levels (2019). The residential class reduced deliveries by 1.3% (after its steep increase of 6.5% in 2020), while C&I classes gained 2.0% and 2.2%, respectively (after respective declines of 5.7% and 13.1% in 2020).

**Q. What are the electric delivery expectations for the forecast horizon of 2025 to 2029?**

A. The 2025 monthly class level results of the electric deliveries forecast process are shown in Exhibit A-2 (EMB-1). The annual class level results for 2025 to 2029 are shown in Exhibit A-3 (EMB-2). Total electric deliveries are expected to increase 3.1% per year for the period 2025 to 2029.

**Q. Are you assuming continued EWR savings as part of your electric deliveries forecast?**

A. Yes. EWR savings are projected to continue growing at around 1.9% the forecast period.

**Q. Please describe the process used to determine the Company's total generation requirements.**

A. The forecasted total electric deliveries are increased by a line loss factor as determined by the 2023 System Loss Study to arrive at the Company's total bundled generation requirements shown in Exhibit A-4 (EMB-3).

## SECTION IV. FORECASTED PEAK DEMAND

**Q. What are the expectations for the growth in peak demand?**

A. The Company uses regression analysis based on the predicted level of electric deliveries to forecast the peak demand. Peak demand is expected to increase by 1.3% per year for the forecast period 2025 to 2029. The monthly system level results of the electric peak demand forecast process is shown in Exhibit A-5 (EMB-4).

**Q. What is the impact to the peak demand forecast from the Company's Smart Energy programs?**

A. The peak demand forecast is reduced by approximately 34 MW in 2025, growing to a reduction of 40 MW by 2029 for the Company's DPP programs, which consist of Peak Time Rewards ("PTR") and Critical Peak Pricing ("CPP").

**Q. To what extent is the Company's EWR program expected to impact peak demand?**

A. The EWR program is projected to reduce peak demand 869 MW in 2025. The cumulative reductions produced by the EWR program are expected to be 1016 MW by 2029.

**Q. To what extent is the CVR program expected to impact peak demand?**

A. The Company's CVR program is expected to reduce peak demand by 62 MW in 2025. The cumulative reductions produced by the Company's CVR program are expected to be 112 MW by 2029.

**Q. To what extent is the Company's new RSP rate expected to impact peak demand?**

A. The residential summer on-peak rate is expected to reduce the Company's peak demand by 92 MW in 2025 and 48 MW by 2029.

**Q. Are capacity-side demand response ("DR") resources accounted for in the Company's peak demand forecast?**

A. No, capacity-side DR resources, such as Residential AC Peak Cycling and C&I DR, which includes Rate GI and Rate EIP, are registered with Midcontinent Independent System Operator, Inc. and are accounted for outside of this peak demand forecast.

**Q. Please explain Exhibit A-6 (EMB-5**).

A. Exhibit A-6 (EMB-5) provides a summary of the system load factor based on the Company's official 2025 to 2029 electric delivery and summer peak demand forecasts.

**Q. Does this conclude your direct testimony?**

A. Yes.

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**EXHIBITS**

**OF**

**EUGÈNE M.J.A. BREURING**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
2025 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-21592
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2024

| | | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) | ( g ) |
|---|---|---|---|---|---|---|---|---|
| Line No. | Month | Residential | Commercial | Industrial | Street Lighting | Inter-departmental | Wholesale | Total |
| 1 | January | 1,176,378 | 1,123,040 | 956,832 | 11,248 | 2,252 | - | 3,269,751 |
| 2 | February | 1,053,281 | 942,509 | 932,681 | 10,435 | 3,008 | - | 2,941,914 |
| 3 | March | 1,018,630 | 995,195 | 999,702 | 8,662 | 2,423 | - | 3,024,612 |
| 4 | April | 884,885 | 948,825 | 935,570 | 7,643 | 2,466 | - | 2,779,389 |
| 5 | May | 884,933 | 1,035,321 | 984,529 | 10,090 | 2,535 | - | 2,917,409 |
| 6 | June | 1,065,857 | 1,114,249 | 989,422 | 5,102 | 2,157 | - | 3,176,788 |
| 7 | July | 1,355,625 | 1,210,860 | 968,707 | 8,702 | 2,769 | - | 3,546,662 |
| 8 | August | 1,246,850 | 1,121,246 | 1,052,006 | 8,500 | 2,771 | - | 3,431,373 |
| 9 | September | 933,858 | 1,038,237 | 994,680 | 9,187 | 2,382 | - | 2,978,345 |
| 10 | October | 846,983 | 1,015,844 | 1,056,511 | 10,697 | 2,645 | - | 2,932,681 |
| 11 | November | 920,180 | 935,727 | 1,065,211 | 11,794 | 2,307 | - | 2,935,219 |
| 12 | December | 1,133,095 | 1,023,686 | 1,016,336 | 12,442 | 2,352 | - | 3,187,911 |
| 13 | Annual | 12,520,554 | 12,504,740 | 11,952,189 | 114,504 | 30,067 | - | 37,122,053 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
2025 Forecast of Calendar Total Electric Deliveries
(MWh)



| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|---|
| Line No. | Month | Residential | Commercial | Industrial | Street Lighting | Inter-departmental | Wholesale | Total |
| 1 | January | 1,176,378 | 1,050,208 | 737,156 | 11,248 | 2,252 | - | 2,977,243 |
| 2 | February | 1,053,281 | 874,510 | 736,260 | 10,435 | 3,008 | - | 2,677,494 |
| 3 | March | 1,018,630 | 923,975 | 790,256 | 8,662 | 2,423 | - | 2,743,947 |
| 4 | April | 884,885 | 877,414 | 728,063 | 7,643 | 2,466 | - | 2,500,470 |
| 5 | May | 884,933 | 960,130 | 754,435 | 10,090 | 2,535 | - | 2,612,123 |
| 6 | June | 1,065,857 | 1,033,582 | 747,829 | 5,102 | 2,157 | - | 2,854,528 |
| 7 | July | 1,355,625 | 1,125,905 | 730,957 | 8,702 | 2,769 | - | 3,223,958 |
| 8 | August | 1,246,850 | 1,035,781 | 802,420 | 8,500 | 2,771 | - | 3,096,322 |
| 9 | September | 933,858 | 959,380 | 767,633 | 9,187 | 2,382 | - | 2,672,441 |
| 10 | October | 846,983 | 938,552 | 829,772 | 10,697 | 2,645 | - | 2,628,649 |
| 11 | November | 920,180 | 862,819 | 838,011 | 11,794 | 2,307 | - | 2,635,110 |
| 12 | December | 1,133,095 | 951,410 | 800,360 | 12,442 | 2,352 | - | 2,899,659 |
| 13 | Annual | 12,520,554 | 11,593,666 | 9,263,153 | 114,504 | 30,067 | - | 33,521,943 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
2025 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-21592
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2024

| Line No. | Month | ( a ) Residential | ( b ) Commercial | ( c ) Industrial | ( d ) Street Lighting | ( e ) Inter-departmental | ( f ) Wholesale | ( g ) Total |
|---|---|---|---|---|---|---|---|---|
| 1 | January | - | 72,832 | 219,676 | - | - | - | 292,508 |
| 2 | February | - | 67,999 | 196,421 | - | - | - | 264,420 |
| 3 | March | - | 71,220 | 209,445 | - | - | - | 280,665 |
| 4 | April | - | 71,412 | 207,507 | - | - | - | 278,919 |
| 5 | May | - | 75,191 | 230,095 | - | - | - | 305,286 |
| 6 | June | - | 80,667 | 241,593 | - | - | - | 322,260 |
| 7 | July | - | 84,954 | 237,750 | - | - | - | 322,704 |
| 8 | August | - | 85,465 | 249,586 | - | - | - | 335,051 |
| 9 | September | - | 78,857 | 227,047 | - | - | - | 305,904 |
| 10 | October | - | 77,293 | 226,739 | - | - | - | 304,032 |
| 11 | November | - | 72,908 | 227,201 | - | - | - | 300,109 |
| 12 | December | - | 72,276 | 215,976 | - | - | - | 288,252 |
| 13 | Annual | - | 911,074 | 2,689,036 | - | - | - | 3,600,110 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Annual Calendar Deliveries
(MWh)

Case No.: U-21592
Exhibit No.: A-3 (EMB-2)
Page: 1 of 1
Witness: EMBreuring
Date: September 2024

| Line No. | Description | ( a ) 2025 | ( b ) 2026 | ( c ) 2027 | ( d ) 2028 | ( e ) 2029 | ( f ) 2025-2029 CAGR |
|---|---|---|---|---|---|---|---|
| 1 | Total Deliveries | | | | | | |
| 2 | Residential | 12,520,554 | 12,576,990 | 12,694,502 | 12,854,006 | 13,013,159 | |
| 3 | Commercial | 12,504,740 | 12,429,797 | 12,406,201 | 12,382,708 | 12,372,709 | |
| 4 | Industrial | 11,952,189 | 13,166,917 | 14,510,008 | 14,948,387 | 16,474,032 | |
| 5 | Street Lighting | 114,504 | 115,201 | 114,016 | 112,967 | 112,967 | |
| 6 | Interdepartmental | 30,067 | 30,470 | 30,325 | 30,513 | 30,261 | |
| 7 | Wholesale | - | - | - | - | - | |
| 8 | Total Deliveries | 37,122,053 | 38,319,375 | 39,755,051 | 40,328,580 | 42,003,128 | 3.1% |
| 9 | Total Full Service | | | | | | |
| 10 | Residential | 12,520,554 | 12,576,990 | 12,694,502 | 12,854,006 | 13,013,159 | |
| 11 | Commercial | 11,593,666 | 11,528,780 | 11,504,372 | 11,484,508 | 11,466,839 | |
| 12 | Industrial | 9,263,153 | 10,500,837 | 11,885,261 | 12,372,810 | 13,906,768 | |
| 13 | Street Lighting | 114,504 | 115,201 | 114,016 | 112,967 | 112,967 | |
| 14 | Interdepartmental | 30,067 | 30,470 | 30,325 | 30,513 | 30,261 | |
| 15 | Wholesale | - | - | - | - | - | |
| 16 | Total Full Service | 33,521,943 | 34,752,278 | 36,228,475 | 36,854,803 | 38,529,994 | 3.5% |
| 17 | Total ROA Service | | | | | | |
| 18 | Residential | - | - | - | - | - | |
| 19 | Commercial | 911,074 | 901,017 | 901,829 | 898,200 | 905,870 | |
| 20 | Industrial | 2,689,036 | 2,666,080 | 2,624,747 | 2,575,577 | 2,567,264 | |
| 21 | Street Lighting | - | - | - | - | - | |
| 22 | Interdepartmental | - | - | - | - | - | |
| 23 | Wholesale | - | - | - | - | - | |
| 24 | Total ROA Service | 3,600,110 | 3,567,097 | 3,526,576 | 3,473,777 | 3,473,134 | -0.9% |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Total Monthly Generation Requirements
(MWh)

Case No.: U-21592
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2024

| Line No. | Month | ( a ) 2025 | ( b ) 2026 | ( c ) 2027 | ( d ) 2028 | ( e ) 2029 |
|---|---|---|---|---|---|---|
| 1 | January | 3,475,045 | 3,588,145 | 3,702,954 | 3,807,729 | 3,871,298 |
| 2 | February | 3,163,110 | 3,293,353 | 3,314,693 | 3,421,946 | 3,492,944 |
| 3 | March | 3,196,884 | 3,265,138 | 3,329,879 | 3,428,717 | 3,505,651 |
| 4 | April | 2,962,888 | 3,104,228 | 3,197,532 | 3,280,080 | 3,434,138 |
| 5 | May | 3,096,347 | 3,199,249 | 3,287,831 | 3,330,507 | 3,474,998 |
| 6 | June | 3,384,218 | 3,502,664 | 3,642,242 | 3,656,441 | 3,789,078 |
| 7 | July | 3,744,038 | 3,766,247 | 3,927,584 | 4,027,374 | 4,191,138 |
| 8 | August | 3,652,758 | 3,740,094 | 3,895,251 | 3,939,757 | 4,084,631 |
| 9 | September | 3,187,693 | 3,260,161 | 3,417,982 | 3,449,880 | 3,648,606 |
| 10 | October | 3,076,238 | 3,218,382 | 3,318,763 | 3,336,522 | 3,443,443 |
| 11 | November | 3,110,926 | 3,217,258 | 3,335,847 | 3,359,118 | 3,517,583 |
| 12 | December | 3,358,230 | 3,456,448 | 3,629,745 | 3,565,626 | 3,752,096 |
| 13 | Annual | 39,408,375 | 40,611,367 | 42,000,303 | 42,603,697 | 44,205,604 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Monthly Full Service Generation Requirements
(MWh)

Case No.: U-21592
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2024

| Line No. | Month | ( a ) 2025 | ( b ) 2026 | ( c ) 2027 | ( d ) 2028 | ( e ) 2029 |
|---|---|---|---|---|---|---|
| 1 | January | 3,161,262 | 3,271,583 | 3,392,333 | 3,502,130 | 3,566,054 |
| 2 | February | 2,879,458 | 3,011,123 | 3,036,719 | 3,148,862 | 3,220,044 |
| 3 | March | 2,895,806 | 2,962,759 | 3,032,830 | 3,136,457 | 3,213,598 |
| 4 | April | 2,663,683 | 2,802,659 | 2,901,456 | 2,988,352 | 3,142,538 |
| 5 | May | 2,768,857 | 2,877,019 | 2,969,202 | 3,017,233 | 3,161,703 |
| 6 | June | 3,038,520 | 3,166,700 | 3,308,801 | 3,328,825 | 3,461,406 |
| 7 | July | 3,397,863 | 3,430,478 | 3,594,017 | 3,699,542 | 3,863,195 |
| 8 | August | 3,293,338 | 3,391,494 | 3,548,826 | 3,599,114 | 3,743,866 |
| 9 | September | 2,859,540 | 2,940,683 | 3,100,861 | 3,137,898 | 3,336,466 |
| 10 | October | 2,750,093 | 2,901,264 | 3,003,613 | 3,026,285 | 3,132,976 |
| 11 | November | 2,788,990 | 2,876,837 | 2,997,656 | 3,025,768 | 3,184,121 |
| 12 | December | 3,049,013 | 3,152,233 | 3,330,920 | 3,267,115 | 3,457,292 |
| 13 | Annual | 35,546,425 | 36,784,830 | 38,217,235 | 38,877,581 | 40,483,259 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Monthly ROA Generation Requirements
(MWh)

Case No.: U-21592
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2024

| Line No. | Month | ( a ) 2025 | ( b ) 2026 | ( c ) 2027 | ( d ) 2028 | ( e ) 2029 |
|---|---|---|---|---|---|---|
| 1 | January | 313,782 | 316,562 | 310,621 | 305,599 | 305,245 |
| 2 | February | 283,652 | 282,230 | 277,975 | 273,084 | 272,900 |
| 3 | March | 301,078 | 302,379 | 297,049 | 292,259 | 292,053 |
| 4 | April | 299,205 | 301,569 | 296,076 | 291,728 | 291,601 |
| 5 | May | 327,490 | 322,230 | 318,629 | 313,274 | 313,294 |
| 6 | June | 345,698 | 335,963 | 333,441 | 327,616 | 327,672 |
| 7 | July | 346,175 | 335,769 | 333,567 | 327,832 | 327,944 |
| 8 | August | 359,420 | 348,600 | 346,425 | 340,643 | 340,765 |
| 9 | September | 328,153 | 319,478 | 317,121 | 311,982 | 312,140 |
| 10 | October | 326,145 | 317,118 | 315,150 | 310,237 | 310,467 |
| 11 | November | 321,936 | 340,422 | 338,190 | 333,350 | 333,462 |
| 12 | December | 309,217 | 304,216 | 298,824 | 298,511 | 294,804 |
| 13 | Annual | 3,861,950 | 3,826,536 | 3,783,068 | 3,726,116 | 3,722,345 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Total Monthly Peak Demand
(MW)

Case No.: U-21592
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2024

| | | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) |
|---|---|---|---|---|---|---|---|
| Line No. | Month | 2025 | 2026 | 2027 | 2028 | 2029 | 2025-2029 CAGR |
| 1 | January | 5,585 | 5,664 | 5,791 | 5,926 | 5,975 | |
| 2 | February | 5,312 | 5,467 | 5,620 | 6,006 | 6,006 | |
| 3 | March | 5,179 | 5,282 | 5,455 | 5,624 | 5,759 | |
| 4 | April | 4,843 | 5,064 | 5,226 | 5,301 | 5,519 | |
| 5 | May | 5,768 | 6,017 | 6,181 | 6,215 | 6,521 | |
| 6 | June | 7,185 | 7,318 | 7,518 | 7,641 | 7,855 | |
| 7 | July | 7,630 | 7,724 | 7,903 | 7,950 | 7,982 | |
| 8 | August | 7,602 | 7,700 | 7,883 | 7,824 | 8,021 | |
| 9 | September | 6,628 | 6,782 | 6,967 | 7,039 | 7,507 | |
| 10 | October | 5,219 | 5,410 | 5,589 | 5,641 | 5,894 | |
| 11 | November | 5,368 | 5,483 | 5,671 | 5,749 | 6,093 | |
| 12 | December | 5,763 | 5,903 | 6,111 | 6,078 | 6,506 | |
| 13 | Peak Demand | 7,630 | 7,724 | 7,903 | 7,950 | 8,021 | 1.3% |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Monthly Full Service Peak Demand
(MW)

Case No.: U-21592
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2024

| | | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) |
|---|---|---|---|---|---|---|---|
| Line No. | Month | 2025 | 2026 | 2027 | 2028 | 2029 | 2025-2029 CAGR |
| 1 | January | 5,153 | 5,232 | 5,366 | 5,509 | 5,564 | |
| 2 | February | 4,894 | 5,017 | 5,179 | 5,567 | 5,587 | |
| 3 | March | 4,769 | 4,871 | 5,054 | 5,229 | 5,371 | |
| 4 | April | 4,395 | 4,620 | 4,793 | 4,872 | 5,091 | |
| 5 | May | 5,312 | 5,557 | 5,740 | 5,783 | 6,094 | |
| 6 | June | 6,669 | 6,814 | 7,021 | 7,153 | 7,378 | |
| 7 | July | 7,149 | 7,254 | 7,442 | 7,491 | 7,533 | |
| 8 | August | 7,079 | 7,180 | 7,372 | 7,312 | 7,521 | |
| 9 | September | 6,109 | 6,269 | 6,462 | 6,524 | 7,059 | |
| 10 | October | 4,773 | 4,977 | 5,164 | 5,228 | 5,489 | |
| 11 | November | 4,932 | 5,056 | 5,252 | 5,305 | 5,654 | |
| 12 | December | 5,353 | 5,499 | 5,711 | 5,683 | 6,114 | |
| 13 | Peak Demand | 7,149 | 7,254 | 7,442 | 7,491 | 7,533 | 1.3% |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecast of Monthly ROA Service Peak Demand
(MW)

Case No.: U-21592
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2024

| | | ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) |
|---|---|---|---|---|---|---|---|
| Line No. | Month | 2025 | 2026 | 2027 | 2028 | 2029 | 2025-2029 CAGR |
| 1 | January | 432 | 432 | 426 | 416 | 411 | |
| 2 | February | 418 | 450 | 442 | 439 | 418 | |
| 3 | March | 410 | 411 | 401 | 394 | 388 | |
| 4 | April | 448 | 444 | 433 | 428 | 428 | |
| 5 | May | 455 | 461 | 440 | 432 | 427 | |
| 6 | June | 516 | 504 | 498 | 488 | 477 | |
| 7 | July | 481 | 470 | 461 | 459 | 449 | |
| 8 | August | 523 | 520 | 511 | 513 | 501 | |
| 9 | September | 518 | 513 | 505 | 515 | 448 | |
| 10 | October | 445 | 432 | 424 | 413 | 405 | |
| 11 | November | 436 | 427 | 420 | 445 | 439 | |
| 12 | December | 411 | 404 | 400 | 396 | 392 | |
| 13 | Peak Demand | 523 | 520 | 511 | 515 | 501 | -1.1% |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Forecasted System Load Factor Based on Summer Peak Demand

Case No.: U-21592
Exhibit No.: A-6 (EMB-5)

Witness: EMBreuring
Date: September 2024

| Line No. | Month | ( a ) 2025 | ( b ) 2026 | ( c ) 2027 | ( d ) 2028 | ( e ) 2029 |
|---|---|---|---|---|---|---|
| 1 | Total Deliveries (GWh) | 37,122 | 38,319 | 39,755 | 40,329 | 42,003 |
| 2 | System Efficiency (%) | 94.2% | 94.4% | 94.7% | 94.7% | 95.0% |
| 3 | Generation Requirements (GWh) | 39,408 | 40,611 | 42,000 | 42,604 | 44,206 |
| 4 | Summer Peak Demand (MW) | 7,630 | 7,724 | 7,903 | 7,950 | 8,021 |
| 5 | System Load Factor (%) | 59.0% | 60.0% | 60.7% | 61.0% | 62.9% |

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**DIRECT TESTIMONY**

**OF**

**ZACHERY S. COLE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Zachery S. Cole, and my business address is 1945 West Parnall Road, 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") where I am a Renewables Engineer responsible for Renewable Resources within the Electric Supply Regulatory Strategies Department.

## QUALIFICATIONS

**Q. Please describe your educational background and business experience.**

A. I received a Bachelor of Science Degree in Civil Engineering in 2020 from Michigan Technological University. From 2021 to 2022, I worked as a Design Engineer at Spicer Group Inc., where I was responsible for permitting, design, construction administration, and cost estimating of water resource related projects. In 2022, I joined Consumers Energy as an Associate Economics Engineer responsible for economic analyses related to new power purchase agreements, renegotiation of existing power purchase agreements, and analysis for ad hoc projects that support the Company's renewable energy electric generation strategy. In September 2023, I was promoted to a new role as a Renewables Engineer where my responsibilities were expanded to include implementation of and the Company's compliance with its Renewable Energy Plan ("RE Plan").

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

A. My responsibilities include the implementation of the RE Plan, including (1) the development of competitive solicitations that add generation under the RE Plan,

(2) negotiations and development of Power Purchase Agreements, and (3) ensuring Company compliance with the RE Plan.

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

A. Yes. I provided testimony in:

- Case No. U-21049: RE Plan expenses in the reconciliation of Power Supply Cost Recovery ("PSCR") Costs and Revenues for the Calendar Year 2022;
- Case No. U-21258: RE Plan expenses in the reconciliation of PSCR Costs and Revenues for the Calendar Year 2023; and
- Case No. U-21549: the Company's 2024 Cost Reconciliation case, regarding the actual and expected expenses incurred to implement the Company's approved RE Plan in 2023, the billed surcharge revenues, and a discussion on the Company's Regulatory Liability Balance projection.

**<u>PURPOSE OF DIRECT TESTIMONY</u>**

**Q. What is the purpose of your direct testimony**?

A. My direct testimony will address the portion of expenses associated with the Company's Renewable Resource Program ("RRP") and RE Plan included in this PSCR Plan.

**Q. Are you sponsoring any exhibits?**

A. No.

**<u>RRP</u>**

**Q. Please describe the RRP?**

A. The RRP was approved by the Commission in January 2005 in Case No. U-13843. Under this RRP, the Company contracts to purchase energy generated by renewable technologies and then allocates the cost of that energy between power supply costs recoverable from PSCR customers and RE costs to be recovered from either voluntary contribution from customers or the Renewable Resource Fund. The Renewable Resource Fund is funded, in part, by a contribution from Midland Cogeneration Venture, LP in accordance with a Settlement Agreement filed and approved by the Commission in Case No. U-15320.

**Q. What level of RRP costs are reflected in this PSCR Plan?**

A. In accordance with the Commission's orders in Case No. U-13843, Consumers Energy has presented for recovery the average PSCR cost of energy delivered. The calculation of the average cost of energy delivered excludes the cost of RRP contracts. The remainder of the cost contracted to be paid to RRP suppliers will be recovered from contributions paid by customers who voluntarily participate in the RRP and then from the Renewable Resource Fund created in Case No. U-13843, *supra*. As the Commission explained in its May 18, 2004 Order in that case:

> Revenues collected from the monthly five-cent charge will be placed into a renewable resource program fund. The fund will be used to compensate Consumers for costs that are not recovered from customers who voluntarily choose the green power program or are not recovered through the PSCR process. Renewable energy contracts entered into by Consumers will be included in its PSCR factor at the average PSCR cost so that inclusion of these contracts will have no effect on the PSCR factor. The difference between the contract price and the average PSCR cost will be recovered through the fund, except for those costs that are being recovered from customers who voluntarily choose the green power program. Consumers should enter into renewable contracts commensurate with the anticipated amount of the fund. The Commission intends to review on a periodic basis the need to continue the fund. [May 18 Order, pages 20-21.]

By only recovering the average cost of energy delivered from the RRP contracts, the Company ensures these contracts will have no effect on the PSCR factor in accordance with the Commission's May 18, 2004 Order in Case No. U-13843.

**RE PLAN**

**Q. Please describe the history of the Company's RE Plan filings?**

A. The Company's original RE Plan was approved by the Commission in its May 26, 2009 Order in Case No. U-15805. The RE Plan was amended with the Commission's orders in Case Nos. U-16543, U-16581, U-17301, U-17752, U-17792, U-18345, U-18393, U-18231, U-20984, and U-21374. The RE Plan, as amended over the years, addresses the measures necessary to comply with MCL 460.1001 *et seq.*

**Q. How are RE Plan costs treated in this PSCR Plan?**

A. As discussed in Case No. U-21374, the Company recovers a portion of the expenses related to its RE Plan through the PSCR via the transfer price mechanism. At the time that an order is issued by the MPSC approving a RE Plan resource, the most recently Commission-approved transfer price schedule is assigned to the resource. The transfer price schedule serves as a point of reference for the expense that can be recovered through the PSCR for that resource. The transfer price schedule assigned to a resource remains with that resource through its useful life. All additional costs are expected to be recovered as Incremental Cost of Compliance and are not included in this PSCR.

**Q. Are there any limits to the amount of expense recovered through PSCR for the resources included in the Company's RE Plan?**

A. Yes. Expenses recovered from PPA resources are limited annually to the lower of the amount established by the Commission or the actual price paid to the supplier multiplied by the number of megawatt hours of renewable energy purchased. When the Company does not project a resulting regulatory asset position, expenses recovered for Company-owned resources can be limited to the lesser of the Levelized Cost of Energy ("LCOE") of the project or the amount established by the commission multiplied by the number of megawatt hours of renewable energy purchased.[1] Expenses recovered for Company-owned resources are otherwise limited to the Transfer Price, multiplied by the number of megawatt hours of renewable energy produced, without limiting the Transfer Price to the project's LCOE.[1]

## SUMMARY

**Q. Please summarize your direct testimony.**

A. My direct testimony explains the portion of expenses associated with the Company's RRP and RE Plan included in this PSCR Plan.

**Q. Does this complete your direct testimony?**

A. Yes, it does.

[1] Expenses for Lake Winds Energy Park are always recovered at the amount established by the Commission multiplied by the number of renewable megawatt hours.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | 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.

**<u>QUALIFICATIONS</u>**

**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.

**<u>POWER SUPPLY COSTS</u>**

**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).

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[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.

**<u>POWER PURCHASE AGREEMENTS</u>**

**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.

**<u>NET INTERCHANGE POWER</u>**

**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.

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 |

**EXHIBITS**

**OF**

**JOSHUA W. HAHN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-7 (JWH-1)

Witness: JWHahn
Date: September 2024

SUMMARY BY SOURCE

| YEAR | | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **ENERGY (MWH)** | | | | | | | | | | | | | |
| 1 | COAL STEAM | 877,739 | 792,796 | 877,739 | 685,502 | 538,736 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,772,513 |
| 2 | GAS & OIL | 1,365,116 | 1,216,262 | 1,014,075 | 934,681 | 1,162,146 | 1,298,000 | 1,415,171 | 1,351,974 | 1,203,701 | 1,015,705 | 1,259,441 | 1,441,501 | 14,677,773 |
| 3 | NUCLEAR PPA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4 | STATION POWER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 5 | CE OWNED RENEWABLES | 199,168 | 229,455 | 259,632 | 217,642 | 170,022 | 143,115 | 122,840 | 115,986 | 134,651 | 191,450 | 241,135 | 225,213 | 2,250,309 |
| 6 | LCREP RENEWABLES | 35,164 | 39,973 | 38,659 | 33,052 | 26,998 | 24,003 | 20,293 | 19,474 | 21,046 | 31,062 | 43,028 | 38,696 | 371,448 |
| 7 | PEAKERS | 50,490 | 175,364 | 98,464 | 125,539 | 108,008 | 93,381 | 222,523 | 224,486 | 94,214 | 108,202 | 29,348 | 5,459 | 1,335,478 |
| 8 | PUMPED STORAGE | 55,953 | 54,246 | 31,009 | 20,850 | 21,379 | 36,708 | 48,669 | 72,643 | 41,021 | 17,983 | 29,016 | 70,531 | 500,009 |
| 9 | TOTAL GENERATED | 2,583,630 | 2,508,096 | 2,319,578 | 2,017,266 | 2,027,290 | 1,595,207 | 1,829,496 | 1,784,563 | 1,494,633 | 1,364,402 | 1,601,968 | 1,781,400 | 22,907,530 |
| 10 | LESS : PUMPING | -77,981 | -60,118 | -40,328 | -27,169 | -38,237 | -47,942 | -53,071 | -94,547 | -53,496 | -34,092 | -37,861 | -86,776 | -651,618 |
| 11 | TOTAL GENERATED | 2,505,649 | 2,447,978 | 2,279,250 | 1,990,097 | 1,989,053 | 1,547,265 | 1,776,425 | 1,690,016 | 1,441,137 | 1,330,310 | 1,564,107 | 1,694,625 | 22,255,912 |
| 12 | PURCHASED (NUGs) | 497,464 | 651,191 | 605,123 | 538,158 | 505,103 | 756,348 | 920,758 | 863,435 | 609,204 | 543,088 | 428,728 | 367,266 | 7,285,866 |
| 13 | NET INTERCHANGE | 158,150 | -219,694 | 11,437 | 135,424 | 274,704 | 734,921 | 700,683 | 739,888 | 809,199 | 876,692 | 796,156 | 987,127 | 6,004,687 |
| 14 | **TOTAL SYSTEM REQUIREMENTS** | 3,161,263 | 2,879,475 | 2,895,810 | 2,663,679 | 2,768,860 | 3,038,534 | 3,397,866 | 3,293,339 | 2,859,540 | 2,750,090 | 2,788,991 | 3,049,018 | 35,546,465 |
| | **VARIABLE EXPENSES ($*1000)** | | | | | | | | | | | | | |
| 15 | COAL STEAM | 24,744 | 22,859 | 25,942 | 20,067 | 15,731 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 109,343 |
| 16 | GAS & OIL | 35,078 | 30,081 | 23,513 | 19,346 | 24,441 | 29,519 | 35,071 | 33,890 | 27,817 | 24,427 | 32,598 | 43,309 | 359,091 |
| 17 | NUCLEAR PPA VARIABLE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | STATION POWER | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | CE OWNED RENEWABLES | 6,994 | 8,353 | 8,765 | 6,950 | 5,287 | 4,773 | 4,913 | 4,775 | 4,834 | 6,685 | 8,606 | 7,270 | 78,205 |
| 20 | PEAKERS | 2,073 | 5,987 | 3,237 | 3,562 | 3,167 | 3,172 | 7,413 | 7,561 | 3,236 | 3,616 | 1,343 | 1,014 | 45,381 |
| 21 | PUMPED STORAGE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | TOTAL GENERATED | 68,889 | 67,280 | 61,458 | 49,925 | 48,627 | 37,463 | 47,396 | 46,226 | 35,888 | 34,727 | 42,547 | 51,594 | 592,020 |
| 23 | LESS : PUMPING | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | TOTAL GENERATED | 68,889 | 67,280 | 61,458 | 49,925 | 48,627 | 37,463 | 47,396 | 46,226 | 35,888 | 34,727 | 42,547 | 51,594 | 592,020 |
| 25 | PURCHASED (PPAs) VARIABLE COST[1] | 24,491 | 29,316 | 27,194 | 24,150 | 22,450 | 32,017 | 41,337 | 39,048 | 25,937 | 21,560 | 16,536 | 14,059 | 318,097 |
| 26 | NET INTERCHANGE, EXCLUDING ZRC | 2,602 | -10,691 | -970 | 2,807 | 7,105 | 21,931 | 19,379 | 22,402 | 23,833 | 26,603 | 25,026 | 31,849 | 171,875 |
| **27** | **TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE** | **95,982** | **85,904** | **87,682** | **76,883** | **78,181** | **91,412** | **108,112** | **107,676** | **85,658** | **82,890** | **84,109** | **97,503** | **1,081,992** |
| 28 | ZONAL RESOURCE CREDIT PURCHASE | 0 | 0 | 0 | 0 | 0 | 1,977 | 2,043 | 2,043 | 3,067 | 3,169 | 3,067 | 1,233 | 16,598 |
| 29 | OWNED RENEWABLE CAPACITY | 4,074 | 4,866 | 5,106 | 4,048 | 3,080 | 2,780 | 2,862 | 2,781 | 2,816 | 3,894 | 5,013 | 4,235 | 45,557 |
| 30 | NUCLEAR PPA CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | PURCHASED (PPA) CAPACITY | 17,405 | 17,466 | 18,948 | 18,716 | 19,029 | 19,370 | 19,123 | 19,005 | 17,343 | 17,003 | 16,360 | 14,443 | 214,211 |
| 32 | PURCHASED (PPA) FIXED ENERGY | 6,908 | 6,640 | 7,308 | 7,250 | 7,615 | 7,442 | 7,352 | 7,308 | 7,001 | 7,002 | 6,721 | 6,650 | 85,195 |
| 33 | INDEPENDENT ADMINISTRATOR EXPENSE | 50 | 50 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 250 |
| 34 | **TOTAL CAPACITY AND NUG FIXED COSTS** | **28,437** | **29,021** | **31,362** | **30,014** | **29,724** | **31,569** | **31,379** | **31,138** | **30,227** | **31,118** | **31,211** | **26,611** | **361,811** |
| 35 | TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION | 45,772 | 43,181 | 42,290 | 38,960 | 46,108 | 57,589 | 62,051 | 61,288 | 52,922 | 42,489 | 43,780 | 47,568 | 583,999 |
| 36 | ACTIVATED CARBON | 163 | 163 | 163 | 163 | 163 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 813 |
| 37 | MISO - SCHEDULE 2 (REACTIVE) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 38 | AQUEOUS AMMONIA EXPENSE | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 178 | 2,138 |
| 39 | UREA EXPENSE | 316 | 316 | 316 | 316 | 316 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1,579 |
| 40 | LIME EXPENSE | 796 | 796 | 796 | 796 | 796 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3,979 |
| 41 | NOX ALLOWANCE | 200 | 200 | 200 | 200 | 200 | 100 | 0 | 0 | 0 | 0 | 0 | 0 | 1,100 |
| 42 | **TOTAL POWER SUPPLY COSTS** | **171,843** | **159,760** | **162,986** | **147,510** | **155,666** | **180,848** | **201,721** | **200,280** | **168,985** | **156,676** | **159,278** | **171,860** | **2,037,413** |
| 43 | LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR) | 9,264 | 9,703 | 7,491 | 7,666 | 8,482 | 8,152 | 7,871 | 8,430 | 8,374 | 8,677 | 9,059 | 10,080 | 103,249 |
| 44 | LARGE ECONOMIC DELVEOPMENT RATE | 0 | 80 | 65 | 66 | 140 | 162 | 416 | 1,270 | 1,132 | 1,053 | 1,903 | 2,569 | 8,856 |
| 45 | **TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS** | **162,580** | **149,976** | **155,431** | **139,777** | **147,044** | **172,534** | **193,434** | **190,580** | **159,479** | **146,946** | **148,316** | **159,211** | **1,925,308** |

[1] Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energy plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-7 (JWH-1)
Page: 2 of 3
Witness: JWHahn
Date: September 2024

PURCHASED AND INTERCHANGE POWER REPORT

| YEAR | | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)** | **(h)** | **(i)** | **(j)** | **(k)** | **(l)** | **(m)** | **(n)** | **(o)** |
| | **PURCHASED AND NET INTERCHANGE RECEIVED (MWH)** | | | | | | | | | | | | | |
| 46 | MARKET ON PEAK | 85,469 | 39,078 | 60,424 | 57,841 | 127,782 | 192,592 | 229,955 | 157,834 | 257,510 | 366,602 | 260,780 | 399,940 | 2,235,807 |
| 47 | MARKET OFF PEAK | 315,680 | 169,922 | 213,447 | 260,471 | 272,136 | 609,089 | 551,231 | 694,419 | 609,496 | 524,341 | 557,437 | 660,164 | 5,437,835 |
| 48 | PURCHASED (PPAs) | 490,886 | 626,190 | 571,084 | 496,855 | 448,313 | 664,416 | 829,761 | 777,566 | 540,578 | 494,500 | 392,704 | 360,667 | 6,693,520 |
| 49 | TOTAL RECEIVED | 892,035 | 835,190 | 844,955 | 815,168 | 848,231 | 1,466,097 | 1,610,948 | 1,629,819 | 1,407,584 | 1,385,444 | 1,210,921 | 1,420,771 | 14,367,162 |
| | **NET INTERCHANGE DELIVERED (MWH)** | | | | | | | | | | | | | |
| 50 | EXTERNAL SALES | 242,999 | 428,695 | 262,433 | 182,889 | 125,214 | 66,759 | 80,506 | 112,365 | 57,808 | 14,252 | 22,062 | 72,977 | 1,668,960 |
| 51 | MISO RAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 52 | TOTAL DELIVERED | 242,999 | 428,695 | 262,433 | 182,889 | 125,214 | 66,759 | 80,506 | 112,365 | 57,808 | 14,252 | 22,062 | 72,977 | 1,668,960 |
| 53 | NET (MWH) | 649,036 | 406,495 | 582,522 | 632,278 | 723,017 | 1,399,338 | 1,530,442 | 1,517,454 | 1,349,776 | 1,371,192 | 1,188,859 | 1,347,794 | 12,698,202 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-7 (JWH-1)
Page: 3 of 3
Witness: JWHahn
Date: September 2024

PURCHASED AND INTERCHANGE POWER REPORT

| YEAR | | JAN | FEB | MAR | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)** | | | | | | | | | | | | | |
| 54 | MARKET ON PEAK ENERGY | 2,894 | 1,358 | 1,921 | 1,753 | 3,823 | 6,497 | 8,347 | 5,917 | 8,597 | 11,817 | 8,833 | 14,236 | 75,993 |
| 55 | MARKET OFF PEAK ENERGY | 9,921 | 5,480 | 6,263 | 6,915 | 7,287 | 17,939 | 17,667 | 21,583 | 17,614 | 15,266 | 17,043 | 21,032 | 164,011 |
| 56 | PURCHASED (PPAs) ENERGY | 23,040 | 27,865 | 25,743 | 22,700 | 20,999 | 30,814 | 40,420 | 38,143 | 25,091 | 20,692 | 15,695 | 13,181 | 304,384 |
| 57 | CASE NO. U-16048 COST RECOVERY | 1,451 | 1,451 | 1,451 | 1,451 | 1,451 | 1,203 | 917 | 905 | 847 | 869 | 841 | 878 | 13,714 |
| 58 | TOTAL EXPENSE | 37,307 | 36,154 | 35,378 | 32,819 | 33,560 | 56,453 | 67,351 | 66,548 | 52,148 | 48,643 | 42,412 | 49,327 | 558,100 |
| | **NET INTERCHANGE CREDIT ($*1000)** | | | | | | | | | | | | | |
| 59 | EXTERNAL SALE ENERGY | 10,213 | 17,531 | 9,154 | 5,861 | 4,005 | 2,506 | 6,635 | 5,099 | 2,378 | 480 | 848 | 3,419 | 68,129 |
| 60 | EXTERNAL SALE CAPACITY | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 61 | MISO RAC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 62 | TOTAL CREDIT | 10,213 | 17,531 | 9,154 | 5,861 | 4,005 | 2,506 | 6,635 | 5,099 | 2,378 | 480 | 848 | 3,419 | 68,129 |
| 63 | NET EXPENSE | 27,093 | 18,623 | 26,225 | 26,958 | 29,555 | 53,948 | 60,715 | 61,449 | 49,770 | 48,163 | 41,564 | 45,908 | 489,972 |

CONSUMERS ENERGY COMPANY
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| YEAR | | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|
| | | SUMMARY BY SOURCE | | | | |
| (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | **ENERGY (MWH)** | | | | | |
| 1 | COAL STEAM | 3,772,513 | 0 | 0 | 0 | 0 |
| 2 | GAS & OIL | 14,677,773 | 13,608,850 | 14,889,146 | 13,834,880 | 14,212,709 |
| 3 | NUCLEAR PPA | 0 | 0 | 0 | 0 | 0 |
| 4 | STATION POWER | 0 | 0 | 0 | 0 | 0 |
| 5 | CE OWNED RENEWABLES | 2,250,309 | 2,900,208 | 4,329,398 | 4,712,908 | 5,600,431 |
| 6 | LCREP RENEWABLES | 371,448 | 873,925 | 448,229 | 871,729 | 870,261 |
| 7 | PEAKERS | 1,335,478 | 825,016 | 574,821 | 577,004 | 627,996 |
| 8 | PUMPED STORAGE | 500,009 | 228,372 | 269,147 | 270,788 | 355,972 |
| 9 | TOTAL GENERATED | 22,907,530 | 18,436,371 | 20,510,741 | 20,267,309 | 21,667,369 |
| 10 | LESS : PUMPING | -651,618 | -301,610 | -361,099 | -368,771 | -480,192 |
| 11 | TOTAL GENERATED | 22,255,912 | 18,134,761 | 20,149,642 | 19,898,538 | 21,187,177 |
| 12 | PURCHASED (NUGs) | 7,285,866 | 7,263,041 | 7,233,188 | 8,336,797 | 8,921,500 |
| 13 | NET INTERCHANGE | 6,004,687 | 11,386,539 | 10,829,623 | 10,634,129 | 10,366,479 |
| 14 | **TOTAL SYSTEM REQUIREMENTS** | 35,546,465 | 36,784,341 | 38,212,453 | 38,869,464 | 40,475,157 |
| | **VARIABLE EXPENSES ($*1000)** | | | | | |
| 15 | COAL STEAM | 109,343 | 301 | 301 | 0 | 0 |
| 16 | GAS & OIL | 359,091 | 375,074 | 411,246 | 379,729 | 386,443 |
| 17 | NUCLEAR PPA VARIABLE | 0 | 0 | 0 | 0 | 0 |
| 18 | STATION POWER | 0 | 0 | 0 | 0 | 0 |
| 19 | CE OWNED RENEWABLES | 78,205 | 78,829 | 78,865 | 78,770 | 52,824 |
| 20 | PEAKERS | 45,381 | 32,102 | 24,533 | 24,250 | 25,789 |
| 21 | PUMPED STORAGE | 0 | 0 | 0 | 0 | 0 |
| 22 | TOTAL GENERATED | 592,020 | 486,306 | 514,945 | 482,749 | 465,056 |
| 23 | LESS : PUMPING | 0 | 0 | 0 | 0 | 0 |
| 24 | TOTAL GENERATED | 592,020 | 486,306 | 514,945 | 482,749 | 465,056 |
| 25 | PURCHASED (PPAs) VARIABLE COST[1] | 318,097 | 339,736 | 362,261 | 392,241 | 423,824 |
| 26 | NET INTERCHANGE, EXCLUDING ZRC | 171,875 | 381,261 | 361,698 | 345,865 | 313,906 |
| 27 | **TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE** | **1,081,992** | **1,207,303** | **1,238,903** | **1,220,855** | **1,202,786** |
| 28 | ZONAL RESOURCE CREDIT PURCHASE | 16,598 | 19,017 | 10,362 | 3,227 | 0 |
| 29 | OWNED RENEWABLE CAPACITY | 45,557 | 45,920 | 45,941 | 45,886 | 30,772 |
| 30 | NUCLEAR PPA CAPACITY | 0 | 0 | 0 | 0 | 0 |
| 31 | PURCHASED (PPA) CAPACITY | 214,211 | 207,581 | 206,889 | 196,059 | 190,640 |
| 32 | PURCHASED (PPA) FIXED ENERGY | 85,195 | 77,129 | 76,658 | 79,253 | 78,601 |
| 33 | INDEPENDENT ADMINISTRATOR EXPENSE | 250 | 250 | 250 | 250 | 250 |
| 34 | **TOTAL CAPACITY AND NUG FIXED COSTS** | **361,811** | **349,896** | **340,100** | **324,674** | **300,262** |
| 35 | TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION | 583,999 | 619,362 | 660,455 | 700,501 | 752,371 |
| 36 | ACTIVATED CARBON | 813 | 0 | 0 | 0 | 0 |
| 37 | MISO - SCHEDULE 2 (REACTIVE) | 0 | 0 | 0 | 0 | 0 |
| 38 | AQUEOUS AMMONIA EXPENSE | 2,138 | 2,301 | 2,462 | 2,385 | 2,622 |
| 39 | UREA EXPENSE | 1,579 | 0 | 0 | 0 | 0 |
| 40 | LIME EXPENSE | 3,979 | 0 | 0 | 0 | 0 |
| 41 | NOX ALLOWANCE | 1,100 | 0 | 0 | 0 | 0 |
| 42 | **TOTAL POWER SUPPLY COSTS** | **2,037,413** | **2,178,863** | **2,241,920** | **2,248,415** | **2,258,041** |
| 43 | LONG-TERM INDUSTRIAL LOAD RETENTION RATE (LTILRR) | 103,249 | 113,045 | 117,250 | 123,585 | 122,386 |
| 44 | LARGE ECONOMIC DELVEOPMENT RATE | 8,856 | 60,467 | 114,293 | 134,800 | 146,897 |
| 45 | **TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS** | **1,925,308** | **2,005,351** | **2,010,377** | **1,990,030** | **1,988,759** |

[1]Purchased (NUG) variable costs include costs associated with PURPA variable energy payments, non-capacity renewable energy plan transfer costs, the green generation program, energy only NUGs and certain hydro plant contract costs

CONSUMERS ENERGY COMPANY
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PURCHASED AND INTERCHANGE POWER REPORT

| YEAR | | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|
| **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)** |
| | **PURCHASED AND NET INTERCHANGE RECEIVED (MWH)** | | | | | |
| 46 | MARKET ON PEAK | 2,235,807 | 4,163,634 | 3,823,048 | 3,982,935 | 4,092,758 |
| 47 | MARKET OFF PEAK | 5,437,835 | 7,826,908 | 8,015,600 | 8,290,258 | 8,769,325 |
| 48 | PURCHASED (PPAs) | 6,693,520 | 6,338,893 | 6,258,801 | 6,441,389 | 6,332,712 |
| 49 | TOTAL RECEIVED | 14,367,162 | 18,329,435 | 18,097,449 | 18,714,581 | 19,194,795 |
| | **NET INTERCHANGE DELIVERED (MWH)** | | | | | |
| 50 | EXTERNAL SALES | 1,668,960 | 604,008 | 1,009,019 | 1,639,062 | 2,495,606 |
| 51 | MISO RAC | 0 | 0 | 0 | 0 | 0 |
| 52 | TOTAL DELIVERED | 1,668,960 | 604,008 | 1,009,019 | 1,639,062 | 2,495,606 |
| 53 | NET (MWH) | 12,698,202 | 17,725,427 | 17,088,430 | 17,075,519 | 16,699,190 |

CONSUMERS ENERGY COMPANY
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PURCHASED AND INTERCHANGE POWER REPORT

| YEAR | | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | **VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)** | | | | | |
| 54 | MARKET ON PEAK ENERGY | 75,993 | 150,608 | 139,255 | 142,336 | 140,340 |
| 55 | MARKET OFF PEAK ENERGY | 164,011 | 257,123 | 266,334 | 266,798 | 265,534 |
| 56 | PURCHASED (PPAs) ENERGY | 304,384 | 327,133 | 355,851 | 389,132 | 422,769 |
| 57 | CASE NO. U-16048 COST RECOVERY | 13,714 | 12,603 | 6,410 | 3,109 | 1,055 |
| 58 | TOTAL EXPENSE | 558,100 | 747,467 | 767,850 | 801,375 | 829,698 |
| | **NET INTERCHANGE CREDIT ($*1000)** | | | | | |
| 59 | EXTERNAL SALE ENERGY | 68,129 | 26,475 | 43,890 | 63,273 | 91,970 |
| 60 | EXTERNAL SALE CAPACITY | 0 | 0 | 0 | 0 | 0 |
| 61 | MISO RAC | 0 | 0 | 0 | 0 | 0 |
| 62 | TOTAL CREDIT | 68,129 | 26,475 | 43,890 | 63,273 | 91,970 |
| 63 | NET EXPENSE | 489,972 | 720,992 | 723,960 | 738,102 | 737,728 |

PROJECTED 2023 RATES

| Line | EXISTING ENERGY - ONLY AGREEMENTS | Energy | Administrative Charge | Capacity | Termination of Agreement |
|---|---|---|---|---|---|
| 1 | Cheboygan Hydro Plant | Three-month rolling average incremental running cost | 0.10¢/kWh | None | Terminated by mutual consent or by either party giving the other at least six months' written notice of its desire to terminate the Agreement at the end of any yearly period. |
| 2 | Jackson County | Agreement Terminated | | | |
| 3 | T.B. Simon Power Plant | Three-month rolling average incremental running cost | 0.10¢/kWh (not to exceed $200/month) | None | Terminated by mutual consent or by either party giving the other at least 30 days' written notice of its desire to terminate the Agreement at the end of any yearly period. |
| 4 | The Power Plant - WMU | Hourly incremental running cost | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 5 | The Michigan Alternative and Renewable Energy Center | 90% of the hourly incremental running cost | None | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 6 | Midland Gas to Energy Plant | 90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh) | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 7 | North American Biofuels – Green Meadow Farms | Agreement Terminated | | | |
| 8 | Muskegon Tech Center Plant | 90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh) | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 9 | Grand Rapids Water Resource Recovery Facility | Real-time LMP | $1/MWh for Delivered Energy | None | Automatic renew for subsequent (1) month periods and shall continue in effect unless and until terminated by mutual agreement or by either party giving the other Party at least one (1) month's written notice |
| 10 | Autocam Medical Solar | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 11 | Cascade Engineering North Plant | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 12 | Gernaat Dairy Meyering Rd | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 13 | Gernaat Dairy Mulder Rd | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 14 | Hearty Fresh Solar | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 15 | Isakson, Raymond | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 16 | Prairie View Solar Farm | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 17 | Ryzebol Dairy, LLC West Mooore Rd | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 18 | Woelfel Solar | Real-time LMP | $1/MWh for Delivered Energy | None | Terminated by mutual consent or by either party giving the other at least one month's written notice of its desire to terminate the Agreement at the end of any monthly period. |
| 19 | Otsego Paper Inc. | Real-time LMP | $1/MWh for Delivered Energy | None | Automatic renew for subsequent (1) month periods and shall continue in effect unless and until terminated by mutual agreement or by either party giving the other Party at least one (1) month's written notice |
| **Line** | **GREEN GENERATION PROGRAM AGREEMENTS** | **Energy** | **Administrative Charge** | **Capacity** | **Termination of Agreement** |
| 1 | Michigan Wind I LLC (Wind) (PPA 1) | Agreement Terminated. | | | |
| 2 | Michigan Wind I LLC (Wind) (PPA 2) | Average PSCR rate | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | December 18, 2028. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination. |
| 3 | Rathbun Generating Station (Landfill Gas) | Agreement Terminated. | | | |
| 4 | Venice Park Generating Facility | Average PSCR rate | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | February 10, 2026. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination. |
| 5 | Zeeland Farm Services, Inc. (Landfill Gas) | Agreement Terminated | | | |
| 6 | C&C Electric 2 Plant | Average PSCR rate | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | None | February 28, 2027. After this date, the agreement shall continue in effect until terminated by mutual agreement or by either party giving the other party at least 365 days' written notice of termination. |

| Line | EXISTING ENERGY & CAPACITY AGREEMENTS | Energy | Administrative Charge | Capacity | Termination of Agreement |
|---|---|---|---|---|---|
| 1 | Ada Cogeneration Ltd Partnership | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 4.024¢/kWh On-Peak, 3.822¢/kWh Off-Peak | January 5, 2026. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 2 | Adrian Energy Associates | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 4.476¢/kWh On-Peak, 4.253¢/kWh Off-Peak | December 13, 2029. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 3 | C&C Energy, formerly Gas Recovery Systems | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | 4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak | February 20, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination. |
| 4 | Cadillac Renewable Energy | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 4.320¢/kWh On-Peak, 4.110¢/kWh Off-Peak | June 15, 2028 |
| 5 | Granger Venice Park | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month) | 4.19¢/kWh On-Peak, 3.98¢/kWh Off-Peak | May 4, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period. |
| 6 | Alverno Hydro Plant | 6.865¢/kWh | 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month) | $11,708.75/ZRC-month | May 31, 2039 |
| 7 | Beaverton, City of | 6.865¢/kWh | 0.10¢/kWh | $11,708.75/ZRC-month | May 31, 2039 |
| 8 | Hope Renewable Energy – Hubbardston | Agreement Terminated. | | | |
| 9 | Irving Hydroelectric | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 4.034¢/kWh On-Peak, 3.832¢/kWh Off-Peak | August 25, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 10 | Commonwealth Power Company – LaBarge | 5.4¢/kWh | 0.10¢/kWh | $8,768.50/ZRC-month | May 31, 2039 |
| 11 | Commonwealth Power Company – Middleville | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 4.034¢/kWh On-Peak, 3.832¢/kWh Off-Peak | January 1, 2031. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 12 | Genesee Power Station Limited Partnership | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (minimum of $200/month, but not to exceed $2,000/month) | 4.65¢/kWh On-Peak, 4.42¢/kWh Off-Peak | December 13, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of any yearly period. |
| 13 | Energy Developments (Byron Center) | 6.396¢/kWh | None | $11,708.75/ZRC-month | May 31, 2039 |
| 14 | Energy Developments (Coopersville) | 6.396¢/kWh | None | $11,708.75/ZRC-month | May 31, 2039 |
| 15 | Energy Developments (Grand Blanc) | 6.396¢/kWh | None | $11,708.75/ZRC-month | May 31, 2039 |
| 16 | Energy Developments (Pinconning) | 6.396¢/kWh | None | $11,708.75/ZRC-month | May 31, 2039 |
| 17 | Grayling Generating Station Limited Partnership | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | 4.18¢/kWh On-Peak, 3.97¢/kWh Off-Peak | December 31, 2027. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of its desire to terminate the Agreement at the end of any yearly period. |
| 18 | Belding Plant | 5.405¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $8,768.50/ZRC-month | May 31, 2039. |
| 19 | Hillman Power Company LLC | Agreement Terminated. | | | |
| 20 | Mass Burn Incinerator Plant | 6.315¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $11,708.75/ZRC-month | May 31, 2039. |
| 21 | Michiana Hydroelectric Co Bellevue | 7.068¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $11,708.75/ZRC-month | May 31, 2039. |
| 22 | Michigan Power Limited Partnership | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 3.880¢/kWh On-Peak, 3.686¢/kWh Off-Peak | October 23, 2030. After this date, the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 23 | Midland Cogeneration Venture Limited Partnership | Cost of Production | 0.10¢/kWh (not to exceed $2,000/month) | 1.014¢/kWh | May 31, 2030. Thereafter, the Agreement shall continue in effect unless and until terminated by mutual agreement or by either Party giving the other Party at least one year's written notice of termination to be effective on May 31, 2030, or at the end of any Planning Period thereafter. |
| 24 | North American Natural Resources, Inc.- (Peoples) | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (minimum of $442/month, but not to exceed $4,421/month) | 4.374¢/kWh On-Peak, 4.155¢/kWh Off-Peak | September 8, 2030. After this date, the Agreement may continue until terminated by mutual consent or by either party giving the other at least 365 day's written notice of termination. |
| 25 | Rathbun Generating Station (Landfill Gas) | 4.76¢/kWh | 0.10¢/kWh - applied to rate in Exhibit A | $8,768.50/ZRC-month | May 31, 2039 |
| 26 | STS Hydropower Ltd – Cascade Hydro Plant | 5.335¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $8,768.50/ZRC-month | May 31, 2039 |

| | | | | | |
|---|---|---|---|---|---|
| 27 | STS Hydropower Ltd – Morrow Hydro Plant | 3.978¢/kWh | 0.10¢/kWh | $5,551.92/ZRC-month | May 31, 2027 |
| 28 | T.E.S. Filer City Station Limited Partnership | Twelve-month rolling average cost of CE coal generation | 0.10¢/kWh (not to exceed $2,000/month) | 6.24¢/kWh On-Peak, 5.30¢/kWh Off-Peak | June 17, 2025. After this date the Agreement may continue from year to year until terminated by mutual consent or by either party giving the other at least one year's written notice of termination to be effective at the end of a calendar year. |
| 29 | STS Hydropower Ltd – Fallasburg Hydro Plant | 5.4¢/kWh | None | $8,768.50/ZRC-month | May 31, 2039. |
| 30 | Viking Energy of Lincoln Limited Partnership | Agreement Terminated. | | | |
| 31 | Viking Energy of McBain Limited Partnership | 4.564¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $11,708.75/ZRC-month | May 31, 2027 The term of this Agreement shall be the period commencing on the Commercial Operation Date of the McBain Michigan Plant and continuing until May 31, 2029 |
| 32 | White's Bridge Hydro Company | 7.068¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $11,708.75/ZRC-month | May 31, 2039. |
| 33 | Boyce Hydro (formerly Wolverine Power Corporation) | Agreement Terminated | | | |
| 34 | STS Hydropower Ltd – Thornapple Ada Hydro Plant | 4.076¢/kWh | None | $11,708.75/ZRC-month | May 31, 2025. |
| 35 | Kleber Hydro | 6.607¢/kWh | None | None | May 31, 2039. |
| 36 | Tower Hydro | 6.607¢/kWh | None | None | May 31, 2039. |
| 37 | Good Fruits Storage, LLC | 3.6¢/kWh On-peak 3.058¢/kWh Off-peak | None | PRA | May 31, 2031. |
| 38 | Hazel Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 39 | Bingham Solar, LLC | 4.538¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 40 | Temperance Solar, LLC | 4.538¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 41 | 13 Mile Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 42 | Captain Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 43 | Coldwater Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 44 | Geddes 1 Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 45 | Interchange Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 46 | Jack Francis Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 47 | May Shannon Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 48 | Stoneheart Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 49 | Workman Road Solar | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 50 | Arthur Solar Farm | Agreement Terminated | | | |
| 51 | Golden Solar Farm | Agreement Terminated | | | |
| 52 | Robert Swift Solar Farm | Agreement Terminated | | | |
| 53 | Angola Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 54 | Geddes 2 Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 55 | Bullhead Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 56 | Hendershot Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2041. |
| 57 | Hogan Solar | 4.579¢/kWh | None | PRA | November 28, 2044. |
| 58 | Entergy Nuclear Power Marketing, LLC | Agreement Terminated | | | |
| 59 | Allegheny Solar | 4.579¢/kWh | None | PRA | July 29, 2044. |
| 60 | Aluminum Solar | 4.579¢/kWh | None | PRA | November 28, 2044. |
| 61 | Blue Elk Solar I | 4.538¢/kWh | None | PRA | May 1, 2044. |
| 62 | Blue Elk Solar III | 4.538¢/kWh | None | PRA | May 5, 2043. |
| 63 | Blue Elk Solar IV | 4.538¢/kWh | None | PRA | May 31, 2043. |
| 64 | Blue Elk Solar VII | 4.538¢/kWh | None | PRA | May 31, 2043. |
| 65 | Calhoun Solar Energy LLC | 3.965¢/kWh | None | $2,775.83/ZRC-month | November 30, 2046 |
| 66 | Cement City Solar, LLC | 4.415¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 67 | Greenstone Solar | 4.538¢/kWh | None | PRA | May 31, 2043. |
| 68 | Johnsfield Solar | 4.579¢/kWh | None | PRA | May 31, 2042. |

| | | | | | |
|---|---|---|---|---|---|
| 69 | Letts Creek Solar, LLC | 4.415¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 70 | Lightfoot Solar | 4.579¢/kWh | None | PRA | May 31, 2043. |
| 71 | Lyons Road Solar | 4.538¢/kWh | None | PRA | May 31, 2042. |
| 72 | Macbeth Solar, LLC | 4.538¢/kWh | None | $11,708.75/ZRC-month | May 31, 2042. |
| 73 | Midcontinent Solar | 4.538¢/kWh | None | PRA | May 31, 2043. |
| 74 | Lake City Solar | 4.155¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 75 | Morey Road Solar | 4.155¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 76 | Surrey Road Solar | 4.155¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 77 | Pullman Solar, LLC | 4.415¢/kWh | None | $11,708.75/ZRC-month | May 31, 2043. |
| 78 | Shipsterns Solar | 4.538¢/kWh | None | PRA | July 1, 2043. |
| 79 | Surbrook Solar | 4.538¢/kWh | None | PRA | January 30, 2044. |
| 80 | TART Solar | Agreement Terminated. | | | |
| 81 | Thorn Lake Solar, LLC | Agreement Terminated | | | |
| 82 | Topanga Solar | 4.538¢/kWh | None | PRA | January 30, 2044. |
| 83 | Wilford Solar | 4.538¢/kWh | None | PRA | September 1, 2043. |
| 84 | Woodley Solar, LLC | 4.479¢/kWh | None | $11,708.75/ZRC-month | May 31, 2042. |
| 85 | Elk Rapids Hydroelectric Power LLC | 7.068¢/kWh | None | $11,708.75/ZRC-month | May 31, 2039. |
| 86 | Bay Windpower I, Mackinaw City, LLC. (Wind) | 3.876¢/kWh | 0.10¢/kWh (not to exceed $2,000/month) | $5,551.92/ZRC-month | May 31, 2024. |
| 87 | Addle Solar, LLC | Agreement Terminated | | | |
| 88 | Byrne Solar | 4.579¢/kWh | None | PRA | May 1, 2043. |
| 89 | Cereal City Solar | 3.526¢/kWh | None | $4,308.33/ZRC-month | May 31, 2048. |
| 90 | Confluence Solar Project | Agreement Terminated | | | |
| 91 | Copenhagen Solar, LLC | 4.538¢/kWh | None | PRA | July 4, 2044. |
| 92 | DSC Corp Center Solar | 3.978¢/kWh | None | $5,551.92/ZRC-month | May 31, 2032. |
| 93 | Heartwood Solar, LLC | 4.985¢/kWh | None | None | December 31, 2049. |
| 94 | Holly Solar, LLC | 4.479¢/kWh | None | PRA | April 4, 2045. |
| 95 | Jackson County Solar Project | 3.823¢/kWh | None | $14,228.8/ZRC-month | May 31, 2040 |
| 96 | Michigan Apple Packers Cooperative, Inc | 3.6¢/kWh On-peak 3.058¢/kWh Off-peak | None | PRA | May 31, 2030. |
| 97 | Olivier Solar, LLC | Agreement Terminated | | | |
| 98 | Puck Solar, LLC | Agreement Terminated | | | |
| 99 | Shoreline Solar, LLC | 4.538¢/kWh | None | PRA | April 5, 2045. |
| 100 | South Christian High School | 3.6¢/kWh On-peak 3.058¢/kWh Off-peak | None | PRA | May 31, 2032. |
| 101 | Sunbelievable Solar, LLC | Agreement Terminated | | | |
| 102 | Superior Sales Inc. | Actual MISO Day Ahead LMP | None | | September 6, 2037 |
| 103 | Heathlands Solar LLC | Agreement Terminated. | | | |

| Line | RENEWABLE ENERGY PLAN AGREEMENTS | Energy | Administrative Charge | Capacity | Termination of Agreement |
|---|---|---|---|---|---|
| 1 | River Fork Solar | Monthly Transfer Rate | None | | May 31, 2042. |
| 2 | Fremont Community Digestor LLC (Anaerobic Digestor) | Monthly Transfer Rate | None | | December 26, 2032. |
| 3 | WM Renewable Energy LLC, Northern Oaks Landfill Plant (Landfill Gas) | Monthly Transfer Rate | None | | November 10, 2030. |
| 4 | North American Natural Resources Inc, Lennon Generating Station (Landfill Gas) | Monthly Transfer Rate | None | | December 15, 2030. |
| 5 | Michigan Wind 2 (Wind) | Monthly Transfer Rate | None | | December 31, 2031. |
| 6 | Harvest II Wind Farm (Wind) | Monthly Transfer Rate | None | | October 31, 2032. |
| 7 | Beebe Renewable Energy, formerly Blissfield Energy (Wind) | Monthly Transfer Rate | None | | December 17, 2032. |
| 8 | WM Renewable Energy LLC, Pine Tree Acres Landfill Plant (Landfill Gas) | Monthly Transfer Rate | None | | February 28, 2032. |
| 9 | Heritage Stoney Corners Wind Farm I, LLC, Phase 2 (Wind) | Monthly Transfer Rate | None | | December 31, 2031. |
| 10 | Heritage Stoney Corners Wind Farm I, LLC, Phase 3 (Wind) | Monthly Transfer Rate | None | | December 31, 2031. |
| 11 | Heritage Garden Wind Farm I, LLC (Wind) | Monthly Transfer Rate | None | | September 13, 2032. |
| 12 | Geronimo Apple Blossom Wind Farm | Monthly Transfer Rate | None | | October 31, 2032. |
| 13 | Experimental Advanced Renewable Program (EARP) (Solar) | Monthly Transfer Rate | None | | Individual contracts have specific termination dates. All agreements will terminate by April 30, 2023. |
| 14 | Experimental Advanced Renewable Program (EARP) Expansion (Solar) | Monthly Transfer Rate | None | | Individual contracts have specific termination dates. All agreements will terminate by August 31, 2029. |
| 15 | Experimental Advanced Renewable Program (EARP) FiT (Anaerobic Digester) | Monthly Transfer Rate | None | | Individual contracts have specific termination dates. All agreements will terminate by June 30, 2036. |

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<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**DIRECT TESTIMONY**

**OF**

**NATHAN J. HOFFMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Nathan J. Hoffman, and my business address is One Energy Plaza, Jackson, Michigan 49201.

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

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director Fossil Generation.

**Q. Please describe your educational background.**

A. In 2003, I received a Bachelor of Science degree in Welding Engineering Technology from Ferris State University. In 2017, I received a Master of Business Administration with a concentration in Advanced Management Tools and Concepts from Ferris State University.

**Q. Please describe your business experience.**

A. In 2005, I joined Consumers Energy at the J.H. Campbell ("Campbell") Generating Complex and progressed through positions from Engineering Technical Analyst to Director Plant Operations, and now hold the position of Executive Director Fossil Generation. In my various roles at Consumers Energy, I served as subject matter expert for boiler and piping systems and was an embedded engineering resource in the operations department, responsible for monitoring and troubleshooting plant performance. I also planned and executed outages to ensure that they were performed in a prudent and expeditious manner, as well as managed the site maintenance organization tasked with maintaining the plant systems and equipment. As the Executive Director of Fossil Generation, I have the overall responsibility for the safe and excellent operations of the Company's Fossil Generation Fleet managing the overall Operating and Maintenance and Capital budgets, developing staffing plans, and strategies to meet Company objectives, while instilling a culture of continuous improvement. Additionally, I oversee the performance of the Fleet's Operations, Maintenance, Fuel Handling, and Environmental and Technical Services departments.

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

A. Yes, I provided testimony in the following MPSC Cases:

- Case No. U-21049: the Company's 2022 Power Supply Cost Recovery ("PSCR") Reconciliation Case;
- Case No. U-21257: the Company's 2023 PSCR Plan Case;
- Case No. U-21423: the Company's 2024 PSCR Plan Case;
- Case No. U-21258: the Company's 2023 PSCR Reconciliation Case.

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

A. The purpose of my direct testimony is to: (i) identify and explain the major fossil and Ludington Pumped Storage Plant ("Ludington") outages that are planned for this period; (ii) identify and support Consumers Energy's periodic outage plans and Random Outage Rate ("ROR") projections for the 2025 PSCR Plan year; (iii) compare the projected ROR for fossil, hydro, Ludington, and peaker units with actual ROR experienced in the five-year historical period 2019 through 2023; (iv) address availability of generating units for the five-year forecast period; (v) identify forecasted urea expenses for the 2025 PSCR Plan year, as well as the forecast period 2026 through 2029; (vi) identify forecasted aqueous ammonia expenses for the 2025 PSCR Plan year, as well as the forecast period 2026 through 2029; (vii) identify forecasted lime expenses for the 2025 PSCR Plan year, as well as the forecast period 2026 through 2029; and (viii) identify forecasted activated carbon expenses for the 2025 PSCR Plan year, as well as the forecast period 2026 through 2029.

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

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-10 (NJH-1) | Major Outages in the 2025 PSCR Plan; |
| Exhibit A-11 (NJH-2) | 2025 PSCR Random Outage Rate Projections; |
| Exhibit A-12 (NJH-3) | 2025-2029 Urea Expense; |
| Exhibit A-13 (NJH-4) | 2025-2029 Aqueous Ammonia Expense; |
| Exhibit A-14 (NJH-5) | 2025-2029 Lime Expense; and |
| Exhibit A-15 (NJH-6) | 2025-2029 Activated Carbon Expense. |

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

A. Yes.

**<u>Major Generating Plant Outages for 2025</u>**

**Q. Please define major generating plant outages.**

A. Major generating plant outages are defined as outages that last 28 days or more. These outages generally deal with major pieces of equipment that require disassembly and repair and/or replacement.

**Q. Please summarize the major outages.**

A. Exhibit A-10 (NJH-1) summarizes the major outages. Company witness Joshua W. Hahn includes these major outages in his modeling of the dispatch of the Company's generating plants in this case.

**Q. Please describe the major outages listed on Exhibit A-10 (NJH-1).**

A. I describe the individual outages, including planned start dates, duration, and significant work scope in the following testimony.

**<u>Ludington Unit 3</u>**

The outage at Ludington Unit 3 is scheduled to begin February 10, 2025 and is projected to last for 41 days – concluding March 23, 2025. The purpose of this periodic outage is for parking ledge and discharge ring condition inspection, penstock, governor controls upgrade, #2 MTB deluge test & electrical testing, oil cooler cleaning, and cooling water strainer cleaning.

**<u>Ludington Unit 4</u>**

The outage at Ludington Unit 4 is scheduled to begin February 10, 2025 and is projected to last for 41 days – concluding March 23, 2025. The purpose of this periodic outage is for parking ledge and discharge ring condition inspection, penstock, governor controls upgrade, #2 MTB deluge test & electrical testing, oil cooler cleaning, and cooling water strainer cleaning.

**<u>Zeeland Unit 1</u>**

The outage at Zeeland Unit 1 is scheduled to begin April 21, 2025 and is projected to last for 34 days – concluding May 25, 2025. The periodic outage is for water wash and major periodic outage inspections.

**<u>Zeeland Unit 2</u>**

The outage at Zeeland Unit 2 is scheduled to begin March 10, 2025 and is projected to last for 34 days – concluding April 13, 2025. The periodic outage is for water wash and major periodic outage inspections.

**Karn Unit 3**

The outage at Karn Unit 3 is scheduled to begin April 16, 2025 and is projected to last for 29 days – concluding May 15, 2025. The periodic outage is for ID fan damper replacement and winter readiness, including inspections and cleaning major components.

**Karn Unit 4**

There is one planned outage at Karn Unit 4 scheduled for 2025. The periodic outage is scheduled to begin October 3, 2025 and is projected to last for 29 days – concluding November 1, 2025. The periodic outage is for Combustion Air Heater and ID/FD dan damper repairs.

**Covert Unit 2**

The outage at Covert Unit 2 is scheduled to begin March 1, 2025 and is projected to last for 59 days – concluding April 29, 2025. The periodic outage is for major inspection of combustion turbine, Balance of Plant (BOP) tasks, and water wash.

**Campbell Units Retirement**

Per the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090, Campbell Units 1, 2, and 3 will be retired as of June 1, 2025.

**Ludington Outages**

**Q. Do any of the Ludington unit outages planned for 2025 reflect work related to Toshiba's defective work?**

A. Yes. Certain limited outages include the performance of work that would have been avoided but for Toshiba workmanship. As discussed in the direct testimony of Consumers Energy witness Hahn, the Company has removed projected power supply costs associated with the procurement of replacement power during these Ludington unit outages. As a result, the maximum PSCR factor requested in this case will not reflect replacement power costs that may ultimately be recorded to a regulatory account pursuant to the Orders in MPSC Case No. U-21310.

**Q. Does the 5-year forecast reflect all of the Ludington unit outages being considered for 2026 through 2029?**

A. No. As discussed in Consumers Energy witness Hahn's direct testimony, the modeling of certain anticipated future outages to correct the Toshiba workmanship on various Ludington units has not yet been performed for purposes of this filing. However, the Company intends to model these outages in its subsequent PSCR Plan filings and anticipates that it will remove replacement power costs to ensure that these costs are similarly moved to a regulatory asset account pursuant to the Orders in MPSC Case No. U-21310.

**Miscellaneous Outages**

**Q. Are other outages projected for 2025?**

A. Yes. In addition to the major outages which I have just discussed, there are other planned outages scheduled for various generating plants with planned durations of less than 28 days. These outages are scheduled to remove zebra mussels from raw water piping, and to perform work on other equipment that will not operate for extended periods without maintenance. To the extent possible, all these planned outages have been scheduled during periods in which the forward market pricing used in modeling of the PSCR Plan is projected to be low.

**ROR Projections**

**Q. How are the ROR projections for the fossil, hydro, and peaker units in this case developed?**

A. The ROR projections in this case are developed using a five-year average (2019 through 2023) and are modified to reflect current operating conditions and recent investments. This is shown in Exhibit A-11 (NJH-2). Generating units which have a projected ROR that varies from their five-year average ROR by more than 10% are described below.

**Karn Unit 3**

The 2025 ROR for Karn Unit 3 is projected to be 18%, lower than the five-year average of 38.7%. The reduction in projected ROR is the result of recent investment in the unit to improve unit availability. The five-year average ROR was elevated due to failure of the Karn Unit 4 induced draft fan 4B (requiring Unit 3 to go offline due to the sharing of a common duct) and the COVID 19 pandemic in 2020.

**Campbell Unit 2**

The 2025 ROR for Campbell Unit 2 is projected to be 15%, as compared to the five-year historical average of 30.27%. The five-year average ROR was elevated primarily due to the failure of the start-up boiler feed pump in August of 2023. The unit was out for the balance of the year.

**Availability**

**Q. Do you provide projections for availability of the generating units?**

A. Yes. The 2025 projected availability for each of the generating units is shown in Exhibit A-11 (NJH-2), column (b).

<u>**Oxides of Nitrogen Emission Allowances**</u>

**Q. Does Consumers Energy expect to incur expenses in 2025 related to the Oxides of Nitrogen ("$NO_x$") emission allowance program?**

A. Yes. Currently the Company is not planning to incur expenses in 2025 under the current NOx emission allowance program for its owned assets, however it does project that it will incur NOx emission allowance expenses for contracted resources. In March 2023, the Environmental Protection Agency ("EPA") finalized the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard."

**Q. Please explain why Consumers Energy does not expect to incur expenses in 2025 related to the $NO_x$ emission allowance program for its owned assets.**

A. The Company has installed Selective Catalytic Reduction ("SCR") units which have significantly reduced $NO_x$ emissions and the associated need to purchase $NO_x$ emissions allowances under the current Cross-State Air Pollution Rule ("CSAPR"). These SCRs were initially installed for compliance with the Clean Air Interstate Rule ("CAIR").

**Q. Please provide background on the status of CAIR.**

A. CAIR was finalized in March 2005 and governed the emission of sulfur dioxide ("$SO_2$") and $NO_x$ from fossil-fueled Electric Generating Units ("EGUs") using an allowance based "cap and trade" program. In this program, one $NO_x$ allowance permitted the emission of one ton of $NO_x$, with the emissions cap and number of allocated allowances decreasing over time. The program regulated $NO_x$ for both the ozone season (May through September) and on an annual basis. Phase I reductions began in 2009 for $NO_x$ emissions and in 2010 for $SO_2$ emissions. Phase II reductions were scheduled to begin in 2015 for both $NO_x$ and $SO_2$ emissions.

In July 2008, CAIR was vacated by the United States Court of Appeals for the District of Columbia ("DC Court of Appeals"), but on rehearing in December 2008, the DC Court of Appeals reinstated the regulation and remanded it back to the EPA to be revised. In August 2011, the EPA finalized the CAIR replacement rule, known as the CSAPR. Phase I of CSAPR was scheduled to take effect on January 1, 2012, and Phase II on January 1, 2014. However, on December 30, 2011, the DC Court of Appeals stayed the rule pending judicial review. As a result of that judicial review, CSAPR was ultimately vacated by the DC Court of Appeals on August 21, 2012. The case then went to the United States Supreme Court ("Supreme Court"). The Supreme Court granted an EPA petition for a rehearing in June 2013. On April 29, 2014, the Supreme Court reversed the DC Circuit Court's Opinion, and remanded the case back to the DC Court of Appeals for additional litigation proceedings. On October 23, 2014, the DC Court of Appeals ordered that the stay of CSAPR be lifted, meaning that Phase I took effect on January 1, 2015. CSAPR compliance levels for 2015-2016 were set at the 2012 through 2013 budget levels, as finalized in the original rule.

**Q. Please describe CSAPR.**

A. CSAPR is a cap and trade rule that is much like CAIR, which it replaced. CSAPR governs the emission of $SO_2$ and $NO_x$ from fossil-fueled EGUs through the use of an allowance-based cap and trade program, except that it restricts interstate trading for use only for addressing relatively small changes in year-to-year emissions variability. Under this program, $NO_x$ is regulated on both an annual basis and on a seasonal basis during the ozone season (May through September). Each allowance (annual or ozone) permits the emission of one ton of $NO_x$, with the emissions cap and number of allocated allowances decreasing over time. $SO_2$ is regulated on an annual basis only, with the emissions cap decreasing over time. Phase I of CSAPR was effective from January 1, 2015 through December 31, 2016, and Phase II became effective on January 1, 2017.

On March 15, 2023, the U.S. EPA issued its final Good Neighbor Plan ("GNP"). For sources in Michigan, the GNP replaced the CSAPR NOx Ozone Season Group 3 Trading starting in the 2023 ozone season control period. The Supreme Court issued a Stay of the GNP on June 27, 2024 and the EPA issued an August 5, 2024 memo stating that it would apply the Stay broadly, including Michigan. Thus, until a decision is provided on the merits of the case, Michigan is now subject to the prior requirements in the CSAPR rule that were in place before the GNP was finalized. We don't expect this to have a significant impact on our allowance availability or costs.

**Q. Is Consumers Energy's fossil generating fleet subject to the requirements of CSAPR?**

A. Yes. Consumers Energy's fossil generating fleet must comply with the requirements of CSAPR.

<u>**$SO_2$ Emission Allowances**</u>

**Q. Does Consumers Energy expect to incur expenses in 2025 related to the $SO_2$ emission allowance program?**

A. No. The Company does not expect to incur expenses related to the consumption of $SO_2$ emission allowances.

**Q. Please explain why Consumers Energy does not expect to incur expenses in 2025 related to the $SO_2$ emission allowance program.**

A. The Company has installed Flue Gas Desulfurization ("FGD") equipment in the form of SDAs and Dry Sorbent Injection ("DSI") at its Campbell site. The FGD units were installed to comply with the EPA's Mercury and Toxics Standards ("MATS"); however, an added co-benefit is the significant reduction in $SO_2$ emission levels.

**Q. Can you please describe MATS?**

A. Yes. MATS is another Federal rule that was finalized by the EPA in December 2011, and regulates emission of mercury, acid gases, certain metals, and organic constituents via emission rate limits or the use of work practices for coal- and oil-fired EGUs. Unlike prior regulations which permit allowance purchases or emission averaging over multiple units, MATS requires unit-by-unit control equipment. Compliance with MATS was required by April 16, 2015; however, the Company received an extension from the Michigan Department of Environment, Great Lakes, and Energy which pushed compliance to April 16, 2016. Consumers Energy has three coal-fired units and two oil-fired units subject to MATS.

**<u>Urea Expenses</u>**

**Q. Are there urea expenses for which Consumers Energy is seeking recovery in 2025?**

A. Yes. Exhibit A-12 (NJH-3) identifies the projected urea expenses from 2025 through 2029.

**Q. Please describe Exhibit A-12 (NJH-3).**

A. In 2025, Consumers Energy projects spending $1.6 million for urea as a necessary expense of operating Campbell Units 2 and 3. For the years 2026 and beyond, urea expenses are expected to drop to $0 due to the retirement of the Campbell Units.

**Q. What is urea and what does Consumers Energy use it for?**

A. Urea is a solid chemical that is converted into ammonia. The ammonia reacts with $NO_x$ gases in the SCR and reduces the amount of $NO_x$ emissions and the need to purchase $NO_x$ allowances.

**Q. How does the projected urea expense compare to the Company's 2024 PSCR Plan case (Case No. U-21423) projections?**

A. The overall decrease in urea expense in 2025 (versus 2024) can be attributed to the reduction in natural gas prices. The elimination of urea expense in 2026 and beyond is a result of the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 which reflects the retirement of Campbell Units 2 and 3 on May 31, 2025. Campbell Unit 1 will also be retired but does not consume urea.

**Q. Has the MPSC previously approved the inclusion of urea in the Company's PSCR?**

A. Yes. The Company requested and received approval to recover urea expenses as a PSCR expense in Case No. U-15415 (2008 PSCR Plan case) and in subsequent PSCR Plan cases.

<u>**Aqueous Ammonia Expenses**</u>

**Q. Are there Aqueous Ammonia expenses for which you are seeking recovery in 2025?**

A. Yes. Exhibit A-13 (NJH-4) identifies the projected aqueous ammonia expenses for the years 2025 through 2029.

**Q. Please describe Exhibit A-13 (NJH-4).**

A. In 2025, Consumers Energy projects spending \$2.1 million for aqueous ammonia as a necessary expense of operating Covert and Zeeland Units 3 and 4 (the Combined Cycle units). In 2026, Consumers Energy expects to spend \$2.3 million for aqueous ammonia associated with the operation of Covert and Zeeland Units 3 and 4. For each of the years

2027 through 2029, expenses are projected to fluctuate slightly from \$2.5 million in 2027 to \$2.4 million in 2028 and then \$2.6 million in 2029.

**Q. How is aqueous ammonia used?**

A. Aqueous ammonia performs the same function as urea, reducing the amount of $NO_x$ emissions and the need to purchase $NO_x$ emission allowances. Both the Covert and Zeeland sites employ SCRs to accomplish $NO_x$ emission reductions.

**Q. How does the projected aqueous ammonia expense compare to the Company's 2024 PSCR Plan case (Case No. U-21423) projections?**

A. The projected expense for aqueous ammonia has increased for the 2025 Plan year as well as the five-year forecast period, due to inflationary escalation of January 2024 actual costs. While the Company retired Karn Units 1 and 2 on May 31, 2023,[1] it also acquired Covert generating station effective June 1, 2023. The amount of aqueous ammonia consumed by Covert for environmental controls far exceeds that of Karn Units 1 and 2, as does the projected generation from Covert. The addition of the Covert site to the Company's generation portfolio was approved in the Company's 2021 IRP, Case No. U-21090.

**Q. Has the Commission previously approved the inclusion of aqueous ammonia in the Company's PSCR?**

A. Yes. The Company requested and received approval to recover aqueous ammonia expense as a PSCR expense in Case No. U-17095 (2013 PSCR Plan case) and in subsequent PSCR Plan cases.

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[1] The June 7, 2019 Order in Case No. U-20165 approved a contested settlement agreement in the Company's 2018 IRP under MCL 460.6t. Consistent with the Company's IRP, the settlement agreement included the provision to retire Karn Units 1 and 2 on May 31, 2023 at the end of the 2022/2023 Midcontinent Independent System Operator, Inc. Planning Year.

**Lime Expenses**

**Q. Are there lime expenses for which you are seeking recovery in 2025?**

A. Yes. Exhibit A-14 (NJH-5) identifies the projected lime expenses for the years from 2025 through 2029.

**Q. Please describe Exhibit A-14 (NJH-5).**

A. In 2025, Consumers Energy projects spending $4 million for lime. For the years 2026 and beyond, lime expenses are expected to drop to $0, due to the retirement of the Campbell units in 2025.

**Q. How will lime be used?**

A. The Company has installed FGD units (a.k.a. SDA and DSI) at its Campbell site. An SDA was installed at Campbell Unit 3 in early 2016; this unit consumes pebble lime. DSI was installed at Campbell Units 1 and 2 in early 2016; these units consume hydrated lime. Lime will be injected into the SDA/DSI where it will react with $SO_2$ and heavy metals found in the exhaust gases. When used in combination with Pulse Jet Fabric Filters ("PJFFs"), $SO_2$ and heavy metal emissions are reduced, allowing the Company to comply with the current emission standards.

**Q. Has the Commission previously approved the inclusion of lime in the Company's PSCR?**

A. Yes. The Company requested and received approval to recover lime expenses as a PSCR expense in Case No. U-17317 (2014 PSCR Plan case) and in subsequent PSCR Plan cases.

**Q. How does the projected lime expense compare to the Company's 2024 PSCR Plan case (Case No. U-21423) projections?**

A. The projected per unit expense for lime reflects an increase for both pebble and hydrated lime, based on inflationary escalation of January 2024 actual costs. Campbell Unit 2 will see an increase in hydrated lime expense due to the plan of burning a 40/60 PRB/Western Bituminous coal blend for 90 days in 2025, before going to zero in 2026 and beyond. The 2025 projected lime expense projected in the Company's 2024 PSCR Plan case (Case No. U-21423) was $8.4 million. The unit costs for pebble and hydrated lime have increased approximately 9% and 29% respectively in the past year, including transportation costs.

The elimination of lime expense in 2026 and beyond is a result of the June 23, 2022 Order Approving Settlement Agreement in IRP Case No. U-21090 which reflects the retirement of Campbell Units 1 through 3 on May 31, 2025.

**<u>Activated Carbon Expenses</u>**

**Q. Are there Activated Carbon expenses for which you are seeking recovery in 2025?**

A. Yes. Exhibit A-15 (NJH-6) identifies the projected activated carbon expenses for the years from 2025 through 2029.

**Q. Please describe Exhibit A-15 (NJH-6).**

A. In 2025, Consumers Energy projects spending $0.8 million for activated carbon as a necessary expense of operating Campbell Units 1 through 3. In the years from 2026 through 2029, no activated carbon expense is forecasted due to the retirement of the Campbell Units.

**Q. How will activated carbon be used?**

A. Activated carbon will be used at the Campbell site. Activated carbon will be housed in a silo, metered, and blown into the flue gas duct through a series of injection lances for in-flight capture of mercury. The collective equipment is known as the activated carbon injection system. The mercury-laden carbon is captured in the PJFF and disposed with the fly ash. Activated carbon reduces mercury emissions, allowing the Company to comply with standards set forth in MATS.

**Q. Has the Commission previously approved the inclusion of activated carbon in the Company's PSCR?**

A. Yes. The Company requested and received approval to recover activated carbon expenses as a PSCR expense in Case No. U-17678 (2015 PSCR Plan case) and in subsequent PSCR Plan cases.

**Q. How does the projected activated carbon expense compare to the Company's 2024 PSCR Plan case (Case No. U-21423) projections?**

A. The projected expense for activated carbon reflects a significant decrease in cost as a result of the Campbell Units retiring in May, 2025. The elimination of activated carbon expense in 2026 reflects the first full year of retirement of the Campbell site as a result of the June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 which reflects the retirement of Campbell Units 1 through 3 on May 31, 2025.

**Q. Does this conclude your direct testimony?**

A. Yes, it does.

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**EXHIBITS**

**OF**

**NATHAN J. HOFFMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

## Major Outages in the 2025 PSCR Plan

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| **Line No.** | **Unit** | **Days in 2025** | **Start Date** | **End Date** |
| 1 | Ludington 3 | 41 | 2/10/2025 | 3/23/2025 |
| 2 | Ludington 4 | 41 | 2/10/2025 | 3/23/2025 |
| 3 | Karn 3 | 29 | 4/16/2025 | 5/15/2025 |
| 4 | Karn 4 | 29 | 10/3/2025 | 11/1/2025 |
| 5 | Covert 2 | 59 | 3/1/2025 | 4/29/2025 |
| 6 | Zeeland 1 | 34 | 4/21/2025 | 5/25/2025 |
| 7 | Zeeland 2 | 34 | 3/10/2025 | 4/13/2025 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-11 (NJH-2)
Page: 1 of 1
Witness: NJHoffman
Date: September 2024

# 2025 PSCR Random Outage Rate Projections

| Line No. | (a) Unit | (b) Availability | (c) Periodic Factor | (d) 2025 Projected ROR | (e) Actual ROR 2019-2023 |
|---|---|---|---|---|---|
| 1 | **Campbell 1** | 84.00% | 0.00% | 16.00% | 16.89% |
| 2 | **Campbell 2** | 85.00% | 0.00% | 15.00% | 30.27% |
| 3 | **Campbell 3** | 92.00% | 0.00% | 8.00% | 14.29% |
| 4 | **Karn 3** | 72.34% | 11.78% | 18.00% | 38.70% |
| 5 | **Karn 4** | 71.44% | 12.88% | 18.00% | 24.76% |
| 6 | **Ludington 1** | 78.85% | 18.29% | 3.50% | 5.06% |
| 7 | **Ludington 2** | 75.78% | 21.47% | 3.50% | 4.94% |
| 8 | **Ludington 3** | 85.55% | 11.35% | 3.50% | 6.81% |
| 9 | **Ludington 4** | 80.26% | 16.83% | 3.50% | 7.75% |
| 10 | **Ludington 5** | 82.88% | 14.11% | 3.50% | 7.34% |
| 11 | **Ludington 6** | 88.48% | 8.31% | 3.50% | 4.97% |
| 12 | **Hydros** | 79.16% | 16.14% | 5.60% | 9.48% |
| 13 | **Zeeland CC** | 88.64% | 7.67% | 4.00% | 7.48% |
| 14 | **Zeeland 1A** | 86.79% | 9.59% | 4.00% | 3.89% |
| 15 | **Zeeland 1B** | 86.79% | 9.59% | 4.00% | 4.45% |
| 16 | **Jackson 1** | 81.11% | 15.07% | 4.50% | 8.22% |
| 17 | **Covert 1** (1) | 88.42% | 4.93% | 7.00% | 4.09% |
| 18 | **Covert 2** (1) | 75.42% | 18.90% | 7.00% | 6.25% |
| 19 | **Covert 3** (1) | 88.42% | 4.93% | 7.00% | 6.08% |

(1) Units acquired June 1, 2023

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-12 (NJH-3)
Page: 1 of 1
Witness: NJHoffman
Date: September 2024

## 2025-2029 Urea Expense

| Line No. | (a) Unit | (b) 2025 | (c) 2026 | (d) 2027 | (e) 2028 | (f) 2029 |
|---|---|---|---|---|---|---|
| 1 | **Campbell 2** | $ 226,245 | $ - | $ - | $ - | $ - |
| 2 | **Campbell 3** | $ 1,353,244 | $ - | $ - | $ - | $ - |
| 3 | **Total** | $ 1,579,489 | $ - | $ - | $ - | $ - |

## 2025-2029 Aqueous Ammonia Expense

| | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| **Line No.** | **Unit** | **2025** | **2026** | **2027** | **2028** | **2029** |
| 1 | **Zeeland** | $ 219,570 | $ 226,930 | $ 233,086 | $ 211,243 | $ 264,725 |
| 2 | **Covert** | $ 1,918,723 | $ 2,074,415 | $ 2,229,204 | $ 2,173,483 | $ 2,356,822 |
| 3 | **Total** | $2,138,293 | $2,301,345 | $2,462,290 | $2,384,726 | $ 2,621,547 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-14 (NJH-5)
Page: 1 of 1
Witness: NJHoffman
Date: September 2024

## 2024-2028 Lime Expense

| Line No. | (a) Unit | (b) 2025 | (c) 2026 | (d) 2027 | (e) 2028 | (f) 2029 |
|---|---|---|---|---|---|---|
| 1 | **Campbell 1** | $ 711,934 | $ - | $ - | $ - | $ - |
| 2 | **Campbell 2** | $ 1,154,215 | $ - | $ - | $ - | $ - |
| 3 | **Campbell 3** | $ 2,113,099 | $ - | $ - | $ - | $ - |
| 4 | **Total** | $ 3,979,248 | $ - | $ - | $ - | $ - |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-15 (NJH-6)

Witness: NJHoffman
Date: September 2024

# 2025-2029 Activated Carbon Expense

| | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| **Line No.** | **Unit** | **2025** | **2026** | **2027** | **2028** | **2029** |
| 1 | **Campbell 1** | $ 273,998 | $ - | $ - | $ - | $ - |
| 2 | **Campbell 2** | $ 166,779 | $ - | $ - | $ - | $ - |
| 3 | **Campbell 3** | $ 372,340 | $ - | $ - | $ - | $ - |
| 4 | **Total** | $ 813,117 | $ - | $ - | $ - | $ - |

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**DIRECT TESTIMONY**

**OF**

**KEVIN C. LOTT, PE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**Q. Would you please state your name and business address?**

A. My name is Kevin C. Lott, and my business address is 1945 Parnall Road, 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 a Principal Electrical Engineer in the Electric Supply Operations – Forecasting group.

**QUALIFICATIONS**

**Q. Would you please describe your educational background and business experience?**

A. I graduated in 2002 with a Bachelor of Science in Electrical Engineering from Michigan State University. I have been employed by Consumers Energy since 2002. Since joining the Company, I have held a variety of engineering and supervisory positions. In 2017, I joined what is now called the Electric Supply Operations ("ESO") organization as the Railcar Fleet Manager in the Fossil Fuel Supply group. In 2018, I was promoted to Fuels Transportation & Planning Director. In 2023, I started a new role in the ESO-Forecasting group as a Principal Electrical Engineer.

**Q. What are your duties as a Principal Electrical Engineer in the ESO-Forecasting group that are relevant to this case?**

A. I am responsible for maintaining Consumers Energy's seasonal capacity data and capacity position forecast, as well as preparing related testimony and filing materials for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission") and Midcontinent Independent System Operator, Inc. ("MISO"). In addition, I continue to be responsible for the following Fuels Transportation & Planning Director duties:

- the preparation of short- and long-term projections specifying fuel purchase volumes;
- the optimization of the distribution of coal to the generating plants to minimize the delivered cost of coal;
- managing plant fuel inventories;
- administering the coal transportation contracts;
- managing the projection of volumes of No. 6 fuel oil for D.E. Karn ("Karn") 3 & 4; and natural gas for Zeeland, Jackson, Covert, and Karn 3 & 4 Plants; and
- preparing testimony and filings for presentation before the MPSC.

**Q. Have you testified in other cases?**

A. Yes. I provided testimony in:

- MPSC Case No. U-20219 (direct and rebuttal), the Company's 2019 Power Supply Cost Recovery ("PSCR") Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2019.
- MPSC Case No. U-20525 (direct and rebuttal), the Company's 2020 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2020.
- MPSC Case No. U-20802 (direct), the Company's 2021 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2021.
- MPSC Case No. U-21048 (direct), the Company's 2022 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2022.
- MPSC Case No. U-21049 (direct), reconciliation of the Company's 2022 PSCR Plan regarding actual as-burned costs and volumes of coal used for electric generation in 2022.

- MPSC Case No. U-21257 (direct), the Company's 2023 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2023.
- MPSC Case No. U-21423 (direct), the Company's 2024 PSCR Plan regarding projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation in 2024.

## STRUCTURE AND PURPOSE OF TESTIMONY

**Q. What is the structure and purpose of your testimony?**

A. My testimony is organized into two sections: Section 1 deals with matters related to fuel for electric generation and Section 2 covers electric generation capacity planning topics. More specifically, in Section 1, I am sponsoring testimony with respect to the Company's projected as-burned costs and volumes of coal, oil, and natural gas used for electric generation. In Section 2, I am sponsoring testimony regarding the forecasted resources that will be used to meet the Company's projected demand and capacity requirements.

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

A. Yes, I am sponsoring the following exhibits that were prepared by me or under my supervision:

| | |
|---|---|
| Exhibit A-16 (KCL-1) | Projected As-Burned Coal Costs (2025-2029); |
| Exhibit A-17 (KCL-2) | Projected As-Burned Oil & Gas Costs (2025-2029); |
| Exhibit A-18 (KCL-3) | Planning Reserve Margin Requirements and Planning Resources to be Acquired – Summer Season; |
| Exhibit A-19 (KCL-4) | Planning Reserve Margin Requirements and Planning Resources to be Acquired – Fall Season; |
| Exhibit A-20 (KCL-5) | Planning Reserve Margin Requirements and Planning Resources to be Acquired – Winter Season; and |

| | |
|---|---|
| Exhibit A-21 (KCL-6) | Planning Reserve Margin Requirements and Planning Resources to be Acquired – Spring Season. |

**<u>SECTION 1: FUEL FOR GENERATION</u>**

**<u>AS-BURNED COAL COSTS</u>**

**Q. Please explain Exhibit A-16 (KCL-1).**

A. Exhibit A-16 (KCL-1) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the years 2025 - 2029. The total annual costs include primary fuel, auxiliary fuel, dust inhibiting treatments, and state air emission fees. It is worth noting that given the planned closure of the remaining coal units in 2025, this exhibit shows that the only as-burned coal costs projected after 2025 are the state air emission fees in 2026 and 2027, which correspond with the emissions from plant operations during 2024 and 2025, respectively.

**Q. How were the as-burned coal costs developed?**

A. The as-burned cost of coal is determined based on the cost of coal in inventory multiplied by the amount of coal projected to be burned during a particular period. Specifically, for each month and each plant inventory location, the delivered cost of coal is added to the cost in inventory at the end of the previous month and divided by the sum of the delivered coal volume for the present month and the volume in inventory at the end of the previous month. This average cost of fuel in inventory is then multiplied by the given burn volume for this inventory location to arrive at the as-burned cost. The month ending inventory is then calculated by subtracting the burn cost and volume, respectively, from the sum of delivered coal values for the month and the starting inventory values. It is important to note that although the coal costs for this case are developed based on as-burned costs, the generation units are dispatched based on the replacement cost of fuel. The reason for this is that once coal is purchased, it becomes a fixed expense for PSCR and economic dispatch purposes. In economic dispatch, only the variable expense relating to coal is included, and is represented by spot coal that will be purchased at the next opportunity, when necessary. coal units are dispatched at this spot coal price so that their production at this price can be compared to the market price for power. This methodology enables the market to help determine whether or not additional coal purchases are necessary throughout the year.

**Q. What is included in the total monthly delivered cost of coal?**

A. The total monthly delivered cost of coal for each generating plant is determined based on the cost of contract and spot coal purchases allocated to the plant, the application of any necessary dust inhibitors to ensure compliance with railroad operating rules and tariffs, as well as the cost of transporting the coal to the plant.

**<u>COAL PRICE DETERMINATION</u>**

**Q. What is the source of the projected coal commodity prices that are included in the as-burned coal cost calculations?**

A. Company witness Angela K. Rissman provided the pricing for all coal contracts as well as projected future market and spot coal purchases.

**<u>COAL TRANSPORTATION CONTRACTS</u>**

**Q. What arrangements does the Company have for the transportation of coal that is purchased for its generating facilities?**

A. Coal is transported by rail from the mines directly to the generating plant sites. During 2025, the Company expects to have in effect two contracts that will provide for the shipment of coal on railroads.

**COAL TRANSPORTATION RATE DETERMINATION**

**Q. What process was used to determine coal transportation rates?**

A. Coal transportation rates were determined by contract pricing, including forecasted periodic adjustments per the terms of each respective contract. Additionally, forecasted fuel surcharges were included according to the terms of the transportation contracts.

**COAL TONNAGE DETERMINATION**

**Q. How were the coal tonnages determined for 2025?**

A. As described in Company witness Joshua W. Hahn's testimony, a computer model is used to determine production estimates (i.e. - MWh production and hence MMBtu coal burn requirements to enable that production) for each generating unit. This model uses a variety of inputs, but those most closely related to fuel quantity determination include fuel price, fuel mix, coal quality, and generating unit efficiency. Using the MMBtu coal burn requirements determined from the model, along with inventory and rail deliverability considerations, the monthly purchase quantities of coal are determined for each plant. A comparison of these purchase requirements with the amount of coal available under contract determines the need for spot coal purchases.

**Q. How many tons of coal has the Company purchased under contract for delivery in 2025 and do you expect to purchase more?**

A. The Company presently has approximately 156,000 tons of coal committed for delivery in 2025 from the multiyear or annual purchases shown in Company witness Rissman's Exhibit A-22 (AKR-1). Currently the Company does anticipate purchasing additional coal in 2024 for 2025 delivery, but the quantity has yet to be determined.

**SPOT COAL PURCHASES**

**Q. How much coal do you expect to purchase on a spot basis during 2025?**

A. Currently, approximately 1.5 million tons of coal are projected to be purchased on a spot basis in 2025; however, this number will be reduced by any amount that is purchased yet in 2024 for 2025 delivery.

**Q. Are any new coal contracts anticipated beyond 2025?**

A. No.

**OIL AND NATURAL GAS PROJECTIONS**

**Q. To which generating plants do your oil and natural gas projections apply?**

A. I am supplying the oil and gas fuel cost projections for the Company's oil-fired and gas-fired generating units, which are the Karn 3 & 4 plants, the Zeeland plant, the Jackson plant, and the Covert plant.

**Q. Please explain Exhibit A-17 (KCL-2).**

A. Exhibit A-17 (KCL-2) summarizes the projected as-burned fuel costs and volumes for the Company's oil-fired and natural gas-fired generating plants for the years 2025 - 2029. The total annual costs include primary fuel, auxiliary fuel, and state air emission fees.

**Q. What is the source of the projected oil and gas commodity prices that are used in these projections?**

A. Company witness Rissman provided these fuel price projections.

**SECTION 2: GENERATION CAPACITY PLANNING**

**CAPACITY PLANNING RESERVE MARGIN REQUIREMENT**

**Q. What is a Planning Reserve Margin Requirement ("PRMR")?**

A. PRMR values, in units of Zonal Resource Credits ("ZRCs"), represent the amount of planned capacity resources that MISO determines each Load Serving Entity ("LSE") (such as Consumers Energy) must have to reliably serve load for the applicable season. A ZRC is a measure of a resource's available capacity after accounting for its outage and operational data; one ZRC of capacity is expected to be sufficient to serve one MW of forecasted demand, providing an appropriate discount for generator operation or effective load carrying capability. As such, each PRMR value is developed to account for generator outages and derates, as well as demand forecast variances, transmission import limitations, weather, and economic uncertainty.

**Q. How are the PRMR values determined?**

A. MISO determines the Company's PRMR for each season of the prompt Planning Year ("PY") using the peak demand forecast and load diversity factor (or coincidence factor) provided by the Company. Among the other inputs that MISO uses to derive these values are the transmission loss factors and Planning Reserve Margin ("PRM") Unforced Capacity ("UCAP") factors for each season. The seasonal transmission loss factors[1] for the prompt PY are calculated by MISO per the process described in Appendix L of its "Resource Adequacy Business Practice Manual" (BPM-011).[2] The seasonal PRM UCAP factors for the prompt PY (as well as future PYs) are among the outputs from a Loss of Load Expectation ("LOLE") study that MISO performs annually.[3] This LOLE study analyzes the probability that various amounts of generation will be adequate to serve firm demand within the MISO footprint. The study results identify the probable amount of generating resources needed to meet the industry standard risk target, which is to limit the expected

[1] 2024-25 Transmission Losses: 2024-2025 Transmission Losses630051.pdf (misoenergy.org)
[2] MISO BPM 11: MISO Business Practices Manuals (misoenergy.org).
[3] April 2024 LOLE report: LOLE Study Report PY 2024-2025631112.pdf (misoenergy.org)

frequency of firm load interruption due to insufficient generation to no more than one day every 10 years (or 0.1 days per year).

**Q. Please explain Exhibits A-18 (KCL-3) through A-21 (KCL-6).**

A. These Exhibits show the Company's electric generation capacity position (line 35) relative to the PRMR (line 8) for each season of each PY shown. In June 2023, MISO changed from an annual to a seasonal construct, which created a PRMR for each of the Summer, Fall, Winter, and Spring seasons; each exhibit represents one of these four seasons.

For the current MISO PY ("PY 2024-25"), lines 1 – 7 on each exhibit show the Company's derivation of the PRMR that was provided by MISO. For the five subsequent PYs, these exhibits show how this same methodology is used to project future PRMR values. More specifically, the Company references the demand forecast discussed in the direct testimony of Company witness Breuring to derive the non-coincident seasonal peak demand values (line 1), as well as the values of the Company's projected peak demand adjustments (line 2), which Mr. Breuring references in his testimony (e.g. – EWR, DPP, CVR, RSP). Since the Company's peak demand has historically occurred at a different time than MISO's peak demand, the Company's capacity requirements are reduced by the aforementioned load diversity factor (line 4). Lines 6 and 7 show the most recent MISO-provided transmission loss factors and PRM UCAP factors by PY, respectively. Lines 3, 5, and 8 are calculated values that are determined by the parameters just described and according to the formulas depicted in column (a) of the exhibits.

**RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT**

**Q. How is Consumers Energy planning to meet the seasonal PRMRs for PY 2025-26?**

A. On Exhibits A-18 (KCL-3) through A-21 (KCL-6), lines 17, 18 and 33 (which are summed on line 34) show the subtotals of ZRCs planned to be available from Company-owned generation, load-modifying resources, and Power Purchase Agreements ("PPAs"), respectively. On each exhibit, lines 9-16 and 19-32 show additional detail regarding the types of generation resources that contribute toward these subtotals. For PY 2025-26 specifically, these values can be found in column (c) of the exhibits.

**Q. What are some examples of load-modifying resources that are included in line 18 of the exhibits?**

A. The Company's load-modifying resources include Peak Power Savers Air Conditioning Peak Cycling ("ACPC"), Commercial and Industrial Demand Response ("C&I DR"), Smart Thermostat Program ("STP"), an Energy Intensive Primary Tariff ("Rate EIP") and an interruptible service provision ("Rate GI").

**Q. Does the Company have sufficient capacity resources to meet the seasonal PRMRs for PY 2025-26?**

A. On Exhibits A-18 (KCL-3) through A-21 (KCL-6) line 35 compares line 34 against line 8, which shows that Consumers Energy currently has sufficient planned resources to meet the projected PRMR (i.e. – line 35 has a positive value) in the Winter season of PY 2025-26; however, the Company does not currently have sufficient planned resources to meet the PRMRs (i.e. – line 35 has negative values) in the Summer, Fall and Spring seasons of PY 2025-26.

**Q. How does the Company plan to address the projected PRMR shortfalls in the Summer, Fall and Spring seasons of PY 2025-26?**

A. The Company is planning to purchase additional ZRCs either through one or more bilateral agreements, through the Planning Resource Auction ("PRA"), or some combination of both.

**<u>CHANGES IMPACTING CAPACITY PLANNING</u>**

**Q. Have there been any changes since filing last year's PSCR Plan (Case No. U-21423) that impact the Company's plans for meeting the PRMRs in PY 2025-26?**

A. Yes. One noteworthy change is an adjustment to MISO's calculation of Seasonal Accredited Capacity ("SAC") values for thermal resources. Per the process described in Appendix Y of its "Resource Adequacy Business Practice Manual" (BPM-011), the Tier-weighting of the final Intermediate SAC ("ISAC") values will change in PY 2025-26. For PY 2024-25 the Tier 1 / Tier 2 weighting was 30 / 70, whereas in PY 2025-26 it will become 20/80. This means that a thermal resource's capacity value for a given season will be more heavily influenced by its available capacity during Tier 2 hours (i.e. - Resource Adequacy ("RA") hours) than it was in the previous PY. RA hours represent the periods of highest risk and greatest need during a season and throughout the PY.

**Q. Are you aware of any other changes that may impact the Company's plans for meeting the PRMRs in future PYs?**

A. Yes. As discussed by Company witness Hahn, certain anticipated future outages to correct the Toshiba workmanship on various Ludington units have not been modeled for purposes of this filing because the outage dates and lengths have not been finalized. The Company expects that these planned outages will impact capacity accreditation in the corresponding planning seasons. The Company intends to reflect these outages and their projected capacity impact in its next State Reliability Mechanism capacity demonstration filing on February 24, 2025, in Case No. U-21775.

**RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION**

**Q. To what extent have the owned resources and PPA resources that are contributing to the Company's projected capacity position in PY 2025-26 been included in previous PSCR Plans and/or Integrated Resource Plans?**

A. The majority of the resources contributing to the values shown on lines 9 through 33 of Exhibits A-18 (KCL-3) through A-21 (KCL-6) were included as part of the Company's last PSCR plan case (Case No. U-21423). Any owned or PPA resources that have been added since that filing are outlined in the testimonies of Company witnesses Hahn and Beth A. Skowronski.

**MISO CAPACITY MARKET**

**Q. How will the costs and revenue associated with the MISO capacity market be treated in the PSCR cases?**

A. Capacity costs and revenues associated with the MISO capacity market are invoiced by MISO daily over the course of the year and are recovered through the annual PSCR reconciliation process.

**Q. Does this complete your prepared direct testimony?**

A. Yes, it does.

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| ______________________________ | ) | |

**EXHIBITS**

**OF**

**KEVIN C. LOTT, PE**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-16 (KCL-1)

Witness: KCLott
Date: September 2024

## Projected As-Burned Coal Costs
**2025 - 2029**

| Line | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | **Burn Volume (Tons)** | | | | | |
| | Plant | 2025 | 2026 | 2027 | 2028 | 2029 |
| 1 | JHCampbell 1-2 | 654,393 | 0 | 0 | 0 | 0 |
| 2 | JHCampbell 3 (CE Owned) | 1,468,050 | 0 | 0 | 0 | 0 |
| 3 | Total Burn Tonnage | 2,122,443 | 0 | 0 | 0 | 0 |
| | **Burn Dollars** | | | | | |
| | Plant | 2025 | 2026 | 2027 | 2028 | 2029 |
| 4 | JHCampbell 1-2 | $ 32,812,150 | $ - | $ - | $ - | $ - |
| 5 | JHCampbell 3 (CE Owned) | $ 74,105,469 | $ - | $ - | $ - | $ - |
| 6 | Total Primary Fuel | $ 106,917,619 | $ - | $ - | $ - | $ - |
| 7 | Total Primary Fuel | $ 106,917,619 | $ - | $ - | $ - | $ - |
| 8 | Total Auxiliary Fuel | $ 1,687,831 | $ - | $ - | $ - | $ - |
| 9 | Total Dust Treatment | $ 437,074 | $ - | $ - | $ - | $ - |
| 10 | State Air Emission Fees | $ 300,736 | $ 300,736 | $ 300,736 | $ - | $ - |
| 11 | Total Coal Burn Cost | $ 109,343,261 | $ 300,736 | $ 300,736 | $ - | $ - |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-17 (KCL-2)

Witness: KCLott
Date: September 2024

## Projected As-Burned Oil & Gas Costs
**2025 - 2029**

| Line | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | **Burn Volume (MCF, unless noted)** | | | | | |
| | Plant | 2025 | 2026 | 2027 | 2028 | 2029 |
| 1 | Zeeland Generating Station | 41,845,868 | 36,688,088 | 34,255,957 | 30,881,874 | 34,628,578 |
| 2 | Jackson Plant | 18,807,486 | 17,013,315 | 18,230,132 | 17,525,066 | 17,224,071 |
| 3 | DEKarn 3-4 - Oil (BBL) | 20,917 | 18,370 | 18,370 | 18,370 | 18,370 |
| 4 | DEKarn 3-4 - Gas | 103,731 | 103,731 | 103,731 | 103,731 | 103,731 |
| 5 | Covert Generating Station | 54,918,524 | 49,219,714 | 57,011,326 | 53,947,106 | 53,423,577 |
| | **Burn Dollars** | | | | | |
| | Plant | 2025 | 2026 | 2027 | 2028 | 2029 |
| 6 | Zeeland Generating Station | $ 137,120,882 | $ 135,149,707 | $ 129,890,142 | $ 117,652,323 | $ 128,364,627 |
| 7 | Jackson Plant | $ 66,442,653 | $ 66,330,416 | $ 70,691,299 | $ 67,000,918 | $ 65,881,015 |
| 8 | DEKarn 3-4 - Oil | $ 1,340,599 | $ 1,135,298 | $ 1,108,294 | $ 1,081,107 | $ 1,071,262 |
| 9 | DEKarn 3-4 - Gas | $ 5,935,170 | $ 5,966,056 | $ 5,967,514 | $ 5,976,489 | $ 5,962,641 |
| 10 | Covert Generating Station | $ 183,165,372 | $ 187,837,332 | $ 216,384,450 | $ 201,439,994 | $ 199,918,609 |
| 11 | Total Primary Fuel | $ 394,004,676 | $ 396,418,810 | $ 424,041,699 | $ 393,150,831 | $ 401,198,155 |
| 12 | Total Primary Fuel | $ 394,004,676 | $ 396,418,810 | $ 424,041,699 | $ 393,150,831 | $ 401,198,155 |
| 13 | Total Auxiliary Fuel | $ 10,348,708 | $ 10,639,058 | $ 11,618,224 | $ 10,709,773 | $ 10,915,415 |
| 14 | State Air Emission Fees | $ 118,535 | $ 118,535 | $ 118,535 | $ 118,535 | $ 118,535 |
| 15 | Total Oil & Gas Burn Cost | $ 404,471,918 | $ 407,176,402 | $ 435,778,458 | $ 403,979,139 | $ 412,232,105 |

## Planning Reserve Margin Requirements and Planned Capacity Resources (ZRC) - Summer Season

| Line | ( a ) | ( b ) PY 2024-25 | ( c ) PY 2025-26 | ( d ) PY 2026-27 | ( e ) PY 2027-28 | ( f ) PY 2028-29 | ( g ) PY 2029-30 |
|---|---|---|---|---|---|---|---|
| 1 | Forecasted Bundled Non-Coincident Peak Demand, MW | 8,009 | 7,960 | 8,131 | 8,328 | 8,412 | 8,436 |
| 2 | Internal Demand Response Programs, applied as adjustment to Peak forecast, MW | 980 | 1,020 | 1,140 | 1,154 | 1,182 | 1,174 |
| 3 | Adjusted Forecasted Bundled Non-Coincident Peak Demand, MW (Line 1 - Line 2) | 7,029 | 6,940 | 6,991 | 7,174 | 7,230 | 7,262 |
| 4 | Load Diversity Factor coincident to MISO, % | 96.32% | 96.32% | 96.32% | 96.32% | 96.32% | 96.32% |
| 5 | Adjusted Forecasted Bundled Coincident Peak Demand, MW (Line 3 x Line 4) | 6,770 | 6,685 | 6,733 | 6,910 | 6,964 | 6,995 |
| 6 | Transmission Loss factor, % | 3.60% | 3.60% | 3.60% | 3.60% | 3.60% | 3.60% |
| 7 | Planning Reserve Margin - UCAP Basis, % | 9.00% | 9.20% | 9.40% | 9.60% | 9.50% | 9.40% |
| 8 | Total Planning Reserve Margin Requirement, ZRC (Line 5 x (1 + Line 6) x (1 + Line 7)) | 7,645 | 7,563 | 7,632 | 7,846 | 7,901 | 7,928 |
| | | | | | | | |
| 9 | Company Owned, In-State, Non-Intermittent, ZRC | 5,407 | 4,292 | 4,494 | 4,537 | 4,683 | 4,808 |
| 10 | Company Owned, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 11 | Company Owned, In-State, Non-Intermittent (BTMG), ZRC | 17 | 17 | 17 | 17 | 17 | 17 |
| 12 | Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 13 | Company Owned, In-State, Intermittent, ZRC | 151 | 150 | 345 | 567 | 567 | 567 |
| 14 | Company Owned, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 15 | Company Owned, In-State, Intermittent (BTMG), ZRC | 13 | 13 | 16 | 16 | 16 | 16 |
| 16 | Company Owned, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 17 | Total Company Owned Generation, ZRC (sum of Lines 9-16) | 5,588 | 4,473 | 4,873 | 5,137 | 5,283 | 5,408 |
| | | | | | | | |
| 18 | Total Load Modifying Resources, Treated as Capacity, ZRC | 571.8 | 631.7 | 649.9 | 656.8 | 656.2 | 655.6 |
| | | | | | | | |
| 19 | PPA, In-State, Non-Intermittent, ZRC | 1,585 | 1,625 | 1,597 | 1,582 | 1,415 | 1,415 |
| 20 | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 21 | PPA, In-State, Non-Intermittent (BTMG), ZRC | 31 | 31 | 27 | 23 | 21 | 15 |
| 22 | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 23 | PPA, In-State, Intermittent, ZRC | 183 | 390 | 655 | 877 | 1,125 | 1,249 |
| 24 | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 25 | PPA, In-State, Intermittent (BTMG), ZRC | 3 | 3 | 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 | 10 | 19 |
| 28 | New Contracts w/ Solar PURPA QFs, ZRC - In-State | 206 | 242 | 277 | 277 | 277 | 277 |
| 29 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 30 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 31 | Net Load Switching, ZRC | - | - | - | - | - | - |
| 32 | Capacity Purchases, ZRC | - | 95 | 70 | - | - | - |
| 33 | Total PPA, ZRC (sum of Lines 19-32) | 2,009 | 2,390 | 2,637 | 2,773 | 2,852 | 2,978 |
| | | | | | | | |
| 34 | Total Planning Resources, ZRC (Line 17 + Line 18 + Line 33) | 8,169 | 7,494 | 8,160 | 8,566 | 8,791 | 9,041 |
| | | | | | | | |
| 35 | UCAP Surplus / (Shortfall), ZRC (Line 34 - Line 8) | 524 | (69) | 528 | 721 | 890 | 1,113 |

## Planning Reserve Margin Requirements and Planned Capacity Resources (ZRC) - Fall Season

| Line | (a) | (b) PY 2024-25 | (c) PY 2025-26 | (d) PY 2026-27 | (e) PY 2027-28 | (f) PY 2028-29 | (g) PY 2029-30 |
|---|---|---|---|---|---|---|---|
| 1 | Forecasted Bundled Non-Coincident Peak Demand, MW | 6,791 | 6,796 | 7,049 | 7,260 | 7,366 | 7,792 |
| 2 | Internal Demand Response Programs, applied as adjustment to Peak forecast, MW | 825 | 855 | 966 | 984 | 1,018 | 1,017 |
| 3 | Adjusted Forecasted Bundled Non-Coincident Peak Demand, MW (Line 1 - Line 2) | 5,966 | 5,941 | 6,083 | 6,276 | 6,347 | 6,776 |
| 4 | Load Diversity Factor coincident to MISO, % | 98.66% | 98.66% | 98.66% | 98.66% | 98.66% | 98.66% |
| 5 | Adjusted Forecasted Bundled Coincident Peak Demand, MW (Line 3 x Line 4) | 5,886 | 5,861 | 6,002 | 6,192 | 6,262 | 6,685 |
| 6 | Transmission Loss factor, % | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% |
| 7 | Planning Reserve Margin - UCAP Basis, % | 14.20% | 14.80% | 15.30% | 15.90% | 15.70% | 15.50% |
| 8 | Total Planning Reserve Margin Requirement, ZRC (Line 5 x (1 + Line 6) x (1 + Line 7)) | 6,916 | 6,924 | 7,121 | 7,385 | 7,456 | 7,945 |
| | | | | | | | |
| 9 | Company Owned, In-State, Non-Intermittent, ZRC | 5,269 | 4,028 | 4,209 | 4,334 | 4,479 | 4,604 |
| 10 | Company Owned, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 11 | Company Owned, In-State, Non-Intermittent (BTMG), ZRC | 17 | 17 | 17 | 17 | 17 | 17 |
| 12 | Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 13 | Company Owned, In-State, Intermittent, ZRC | 131 | 130 | 325 | 547 | 547 | 547 |
| 14 | Company Owned, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 15 | Company Owned, In-State, Intermittent (BTMG), ZRC | 14 | 13 | 16 | 16 | 16 | 16 |
| 16 | Company Owned, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 17 | Total Company Owned Generation, ZRC (sum of Lines 9-16) | 5,430 | 4,189 | 4,567 | 4,913 | 5,059 | 5,184 |
| | | | | | | | |
| 18 | Total Load Modifying Resources, Treated as Capacity, ZRC | 231.6 | 238.5 | 244.5 | 250.5 | 250.5 | 250.4 |
| | | | | | | | |
| 19 | PPA, In-State, Non-Intermittent, ZRC | 1,572 | 1,604 | 1,573 | 1,556 | 1,405 | 1,405 |
| 20 | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 21 | PPA, In-State, Non-Intermittent (BTMG), ZRC | 32 | 32 | 27 | 24 | 22 | 16 |
| 22 | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 23 | PPA, In-State, Intermittent, ZRC | 231 | 389 | 654 | 875 | 1,123 | 1,247 |
| 24 | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 25 | PPA, In-State, Intermittent (BTMG), ZRC | 3 | 3 | 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 | 10 | 19 |
| 28 | New Contracts w/ Solar PURPA QFs, ZRC - In-State | 166 | 196 | 231 | 231 | 231 | 231 |
| 29 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 30 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 31 | Net Load Switching, ZRC | - | - | - | - | - | - |
| 32 | Capacity Purchases, ZRC | - | 105 | 70 | - | - | - |
| 33 | Total PPA, ZRC (sum of Lines 19-32) | 2,003 | 2,331 | 2,566 | 2,699 | 2,794 | 2,920 |
| | | | | | | | |
| 34 | Total Planning Resources, ZRC (Line 17 + Line 18 + Line 33) | 7,665 | 6,758 | 7,377 | 7,862 | 8,103 | 8,354 |
| | | | | | | | |
| 35 | UCAP Surplus / (Shortfall), ZRC (Line 34 - Line 8) | 749 | (166) | 256 | 477 | 648 | 410 |

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-20 (KCL-5)

Witness: KCLott
Date: September 2024

## Planning Reserve Margin Requirements and Planned Capacity Resources (ZRC) - Winter Season

| Line | (a) | (b) PY 2024-25 | (c) PY 2025-26 | (d) PY 2026-27 | (e) PY 2027-28 | (f) PY 2028-29 | (g) PY 2029-30 |
|---|---|---|---|---|---|---|---|
| 1 | Forecasted Bundled Non-Coincident Peak Demand, MW | 5,989 | 5,932 | 6,146 | 6,374 | 6,339 | 6,779 |
| 2 | Internal Demand Response Programs, applied as adjustment to Peak forecast, MW | 743 | 780 | 871 | 887 | 880 | 908 |
| 3 | Adjusted Forecasted Bundled Non-Coincident Peak Demand, MW (Line 1 - Line 2) | 5,246 | 5,152 | 5,275 | 5,487 | 5,459 | 5,871 |
| 4 | Load Diversity Factor coincident to MISO, % | 98.64% | 98.64% | 98.64% | 98.64% | 98.64% | 98.64% |
| 5 | Adjusted Forecasted Bundled Coincident Peak Demand, MW (Line 3 x Line 4) | 5,175 | 5,082 | 5,203 | 5,412 | 5,385 | 5,791 |
| 6 | Transmission Loss factor, % | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% | 4.00% |
| 7 | Planning Reserve Margin - UCAP Basis, % | 27.40% | 27.20% | 27.00% | 26.80% | 26.50% | 26.30% |
| 8 | Total Planning Reserve Margin Requirement, ZRC (Line 5 x (1 + Line 6) x (1 + Line 7)) | 6,857 | 6,723 | 6,872 | 7,137 | 7,084 | 7,607 |
| | | | | | | | |
| 9 | Company Owned, In-State, Non-Intermittent, ZRC | 5,709 | 4,505 | 4,540 | 4,545 | 4,559 | 4,572 |
| 10 | Company Owned, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 11 | Company Owned, In-State, Non-Intermittent (BTMG), ZRC | 17 | 17 | 17 | 17 | 17 | 17 |
| 12 | Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 13 | Company Owned, In-State, Intermittent, ZRC | 395 | 395 | 414 | 500 | 500 | 500 |
| 14 | Company Owned, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 15 | Company Owned, In-State, Intermittent (BTMG), ZRC | 14 | 13 | 16 | 16 | 16 | 16 |
| 16 | Company Owned, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 17 | Total Company Owned Generation, ZRC (sum of Lines 9-16) | 6,135 | 4,930 | 4,987 | 5,078 | 5,092 | 5,105 |
| | | | | | | | |
| 18 | Total Load Modifying Resources, Treated as Capacity, ZRC | 326.3 | 332.5 | 338.5 | 344.6 | 343.8 | 343.2 |
| | | | | | | | |
| 19 | PPA, In-State, Non-Intermittent, ZRC | 1,637 | 1,637 | 1,637 | 1,576 | 1,442 | 1,442 |
| 20 | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 21 | PPA, In-State, Non-Intermittent (BTMG), ZRC | 28 | 27 | 22 | 19 | 19 | 12 |
| 22 | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 23 | PPA, In-State, Intermittent, ZRC | 198 | 299 | 497 | 583 | 603 | 615 |
| 24 | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 25 | PPA, In-State, Intermittent (BTMG), ZRC | 4 | 4 | 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 | 9 | 17 |
| 28 | New Contracts w/ Solar PURPA QFs, ZRC - In-State | 12 | 15 | 18 | 18 | 18 | 18 |
| 29 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 30 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 31 | Net Load Switching, ZRC | - | - | - | - | - | - |
| 32 | Capacity Purchases, ZRC | - | 95 | 70 | - | - | - |
| 33 | Total PPA, ZRC (sum of Lines 19-32) | 1,879 | 2,078 | 2,255 | 2,209 | 2,095 | 2,107 |
| | | | | | | | |
| 34 | Total Planning Resources, ZRC (Line 17 + Line 18 + Line 33) | 8,341 | 7,341 | 7,580 | 7,631 | 7,531 | 7,555 |
| | | | | | | | |
| 35 | UCAP Surplus / (Shortfall), ZRC (Line 34 - Line 8) | 1,484 | 618 | 708 | 494 | 447 | (52) |

## Planning Reserve Margin Requirements and Planned Capacity Resources (ZRC) - Spring Season

| Line | ( a ) | ( b ) PY 2024-25 | ( c ) PY 2025-26 | ( d ) PY 2026-27 | ( e ) PY 2027-28 | ( f ) PY 2028-29 | ( g ) PY 2029-30 |
|---|---|---|---|---|---|---|---|
| 1 | Forecasted Bundled Non-Coincident Peak Demand, MW | 6,066 | 6,229 | 6,402 | 6,480 | 6,773 | 7,151 |
| 2 | Internal Demand Response Programs, applied as adjustment to Peak forecast, MW | 772 | 811 | 845 | 865 | 863 | 904 |
| 3 | Adjusted Forecasted Bundled Non-Coincident Peak Demand, MW (Line 1 - Line 2) | 5,294 | 5,418 | 5,556 | 5,615 | 5,910 | 6,248 |
| 4 | Load Diversity Factor coincident to MISO, % | 98.66% | 98.66% | 98.66% | 98.66% | 98.66% | 98.66% |
| 5 | Adjusted Forecasted Bundled Coincident Peak Demand, MW (Line 3 x Line 4) | 5,223 | 5,346 | 5,482 | 5,540 | 5,831 | 6,164 |
| 6 | Transmission Loss factor, % | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% | 2.90% |
| 7 | Planning Reserve Margin - UCAP Basis, % | 26.70% | 28.70% | 30.70% | 32.80% | 33.10% | 33.50% |
| 8 | Total Planning Reserve Margin Requirement, ZRC (Line 5 x (1 + Line 6) x (1 + Line 7)) | 6,809 | 7,079 | 7,373 | 7,571 | 7,986 | 8,468 |
| | | | | | | | |
| 9 | Company Owned, In-State, Non-Intermittent, ZRC | 5,139 | 4,057 | 4,240 | 4,282 | 4,428 | 4,553 |
| 10 | Company Owned, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 11 | Company Owned, In-State, Non-Intermittent (BTMG), ZRC | 17 | 17 | 17 | 17 | 17 | 17 |
| 12 | Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 13 | Company Owned, In-State, Intermittent, ZRC | 157 | 157 | 352 | 573 | 573 | 573 |
| 14 | Company Owned, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 15 | Company Owned, In-State, Intermittent (BTMG), ZRC | 20 | 19 | 21 | 21 | 21 | 21 |
| 16 | Company Owned, Out-of-State, Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 17 | Total Company Owned Generation, ZRC (sum of Lines 9-16) | 5,333 | 4,250 | 4,629 | 4,893 | 5,039 | 5,164 |
| | | | | | | | |
| 18 | Total Load Modifying Resources, Treated as Capacity, ZRC | 308.4 | 319.8 | 326.9 | 334.0 | 334.0 | 334.1 |
| | | | | | | | |
| 19 | PPA, In-State, Non-Intermittent, ZRC | 1,621 | 1,626 | 1,626 | 1,572 | 1,434 | 1,434 |
| 20 | PPA, Out-of-State, Non-Intermittent, ZRC | - | - | - | - | - | - |
| 21 | PPA, In-State, Non-Intermittent (BTMG), ZRC | 34 | 29 | 25 | 23 | 23 | 14 |
| 22 | PPA, Out-of-State, Non-Intermittent (BTMG), ZRC | - | - | - | - | - | - |
| 23 | PPA, In-State, Intermittent, ZRC | 247 | 405 | 670 | 891 | 1,138 | 1,263 |
| 24 | PPA, Out-of-State, Intermittent, ZRC | - | - | - | - | - | - |
| 25 | PPA, In-State, Intermittent (BTMG), ZRC | 4 | 4 | 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 | 11 | 20 |
| 28 | New Contracts w/ Solar PURPA QFs, ZRC - In-State | 182 | 212 | 247 | 247 | 247 | 247 |
| 29 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 30 | Other Forward Capacity Contract, ZRC - Out-of-State | - | - | - | - | - | - |
| 31 | Net Load Switching, ZRC | - | - | - | - | - | - |
| 32 | Capacity Purchases, ZRC | - | 95 | 70 | - | - | - |
| 33 | Total PPA, ZRC (sum of Lines 19-32) | 2,089 | 2,374 | 2,651 | 2,748 | 2,858 | 2,983 |
| | | | | | | | |
| 34 | Total Planning Resources, ZRC (Line 17 + Line 18 + Line 33) | 7,730 | 6,943 | 7,607 | 7,975 | 8,231 | 8,481 |
| | | | | | | | |
| 35 | UCAP Surplus / (Shortfall), ZRC (Line 34 - Line 8) | 921 | (136) | 234 | 404 | 245 | 13 |

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**DIRECT TESTIMONY**

**OF**

**ANGELA K. RISSMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Angela K. Rissman, and my business address is 1945 Parnall Road, 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 Fuel Procurement Manager in the Fossil Fuel Supply Section of the Electric Supply Department.

**QUALIFICATIONS**

**Q. Would you please describe your educational background and business experience?**

A. I graduated from Western Michigan University in 1996 with a Bachelor of Business Administration in Accountancy and from Central Michigan University in 1999 with a Master of Science in Administration. I began working for CMS Enterprises in 2005 and for Consumers Energy in 2007. I have held several positions of increasing responsibility in the Electric Supply Operations Department, and specifically began work in the Fossil Fuel Supply Section in November 2013. I was promoted to Manager of Coal Procurement in November 2017 and Fuel Procurement Manager in October 2022.

**Q. What are your duties as the Fuel Procurement Manager?**

A. My responsibilities include purchasing the coal, natural gas, and oil fuels used at the Company's electric generating plants; providing economic evaluations and providing procurement alternatives, negotiating and managing associated fuel contracts; assuring quality standards are met; supporting relevant accounting functions; and the preparation of testimony and exhibits for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

**Q. Have you testified in other cases before the MPSC?**

A. Yes. I provided testimony in:

- Case No. U-18142 – 2017 Power Supply Cost Recovery (“PSCR”) Plan;
- Case No. U-20068 – 2017 PSCR Reconciliation;
- Case No. U-18402 – 2018 PSCR Plan;
- Case No. U-20202 – 2018 PSCR Reconciliation;
- Case No. U-20219 – 2019 PSCR Plan;
- Case No. U-20220 – 2019 PSCR Reconciliation;
- Case No. U-20525 – 2020 PSCR Plan;
- Case No. U-20526 – 2020 PSCR Reconciliation;
- Case No. U-20802 – 2021 PSCR Plan;
- Case No. U-20803 – 2021 PSCR Reconciliation;
- Case No. U-21048 – 2022 PSCR Plan;
- Case No. U-21049 – 2022 PSCR Reconciliation
- Case No. U-21257 – 2023 PSCR Plan;
- Case No. U-21258 – 2023 PSCR Reconciliation; and
- Case No. U-21423 – 2024 PSCR Plan.

**<u>PURPOSE OF DIRECT TESTIMONY</u>**

**Q. What is the purpose of your direct testimony?**

A. I am sponsoring direct testimony with respect to the Company’s coal, natural gas, and oil purchases and procurement strategy for electric generation for the 2025-2029 period. In addition, I will support the Company’s proposal to include a contingency mechanism based upon projected New York Mercantile Exchange ("NYMEX") gas prices that was originally presented in the Company's 2024 PSCR Plan case (Case No. U-21423).

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

A. Yes, I am sponsoring the following exhibits that were prepared by me or under my supervision:

| | |
|---|---|
| Exhibit A-22 (AKR-1) | Coal Contract & Purchase Data; and |
| Exhibit A-23 (AKR-2) | 2025 Forecasted Natural Gas Prices and 2024 Comparison of Forecasted vs. Actual Natural Gas Prices. |

## <u>COAL PURCHASE STRATEGY</u>

**Q. What actions has the Company taken to minimize its cost of coal and ensure adequate supply to meet customer demand?**

A. The Fuel Supply Department endeavors to secure coal supplies in quantity and quality sufficient to meet the needs of the Company's coal-fired generating units in a cost-effective manner. Coal from different regions is evaluated and purchased based on total delivered cost. Spot, annual, and multi-year contracts are made with coal suppliers to ensure a secure supply of fuel at the most economical value available. All contracts are competitively bid and to the extent possible, structured to allow volume flexibility in response to potential changes in market conditions.

**Q. Can you elaborate on the Company's coal purchasing strategy?**

A. Yes. The Company layers its coal purchases in such a way that each year it has a portfolio of coal purchase contracts. The portfolio for a given year will consist of contracts with various coal quality specifications, volumes, term lengths, and prices. Although these purchases are competitively bid, the pricing of these contracts if reflective of the market at the time the purchase was made. Some contracts within the portfolio may be above or below the market at the time of delivery depending on how the market has changed relative to the time the purchase was made. Maintaining such a portfolio minimizes price risk to customers and protects them from price volatility in the market. In addition to providing stability in pricing, procuring coal supplies in such a manner also mitigates supply risk to customers in the event coal supplies become constrained. Quantities of coal are secured over time that typically positions the Company to have approximately 70% to 90% of its anticipated total volume secured by the fall of each year for the following calendar year; approximately 40% to 50% secured for the next calendar year; and up to 20% to 25% secured for the third calendar year.

**Q. Have there been any changes to coal purchase strategy for 2025 from the previous PSCR filings?**

A. Yes. Whereas the Company will be retiring its last coal plant in 2025, the typical procurement strategy as just described is being adjusted to ensure there is adequate coal to support end of life operations and minimize the risk of being over committed. We anticipate this will be accomplished through a flexible "balance of plant requirements" purchase expected to be in place by December 31, 2024.

**<u>ENVIRONMENTAL CONSIDERATIONS</u>**

**Q. Would you briefly explain the air pollution considerations that have been an impact on the Company's coal supply purchasing program?**

A. In September 2014, the Company reached an agreement with the Environmental Protection Agency and the U.S. Department of Justice regarding emission limits for emission of nitrogen oxides, sulfur dioxides, and particulate matter at each of Consumers Energy's coal-fired units. These limitations as set forth in the Consent Decree have been incorporated into the Company's Renewable Operating Permits for each site. These restrictions dictate the quality of coal that can be purchased. In order to comply with the permit limitations, the Company will purchase only wester and/or low sulfur eastern coal.

These federally enforceable limits were, by operation of the Consent Decree, incorporated into the Renewable Operating Permit ("ROP" also known as the Title V permit or air permit as issued by the State) with the Michigan Department of Environmental Quality, now known as the Michigan Department of Environment, Great Lakes, and Energy on December 21, 2017 for J.H. Campbell ("Campbell").

**COAL PURCHASE CONTRACTS**

**Q. Please describe Exhibit A-22 (AKR-1).**

A. Exhibit A-22 (AKR-1) shows all current and expected coal contracts providing for the 2025 delivery period.

The contract provides western coal supply for the Campbell coal plant. Column (a) lists the supplier, which for this exhibit is represented by contract number. Column (b) identifies the coal type, column (c) is the date that the contract was fully executed, and columns (d) and (e) identify the starting and ending dates for the contract, respectively. Column (f) identifies the contract commitment volumes or the volume the Company presently expects to nominate. Column (g) defines the contract price ($/ton).

**Q. Could you briefly explain the term "nominate"?**

A. Some of our coal contracts offer the Company the ability to specify, or "nominate," a purchase volume typically on a quarterly, six-month, or annual basis, within a contract-specified minimum and maximum tonnage. This ability to "nominate" tonnage provides the Company with some flexibility to respond to evolving demand and market conditions by taking more or less tonnage from a given contract depending upon anticipated coal requirements and depending on the contract's price compared to the projected price of coal that may be available for purchase during the nomination period.

**Q. Do you anticipate entering into any additional coal supply contracts from which tonnage would be received in 2025?**

A. Yes. We anticipate issuing a solicitation for additional coal before the end of 2024 for delivery in 2025.

**<u>COAL PRICE DETERMINATION</u>**

**Q. What coal commodity prices were used to develop the as-burned cost of coal included in the direct testimony sponsored by Company witness Kevin C. Lott?**

A. For existing contracts, the Company based the projected coal prices on the actual coal contract pricing, whether based on a fixed price or on a price tied to an index using the projected index price. For the remaining open position, the prices were estimated based on the spot market projections for that period.

**Q. What was considered when estimating spot prices?**

A. Spot market prices for coal are generally consistent with current market conditions and fluctuate with supply and demand, economic conditions, environmental compliance requirements, coal mining industry capacity, alternative fuel prices, strikes, and other factors.

**Q. What spot prices for coal were assumed in this filing?**

A. The spot price for western sub-bituminous coal assumed in this filing for 2025 is $14.00/Ton.[1]

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[1] The sources for this data include Argus Coal Daily and internal fossil fuel supply department model projections.

**OIL AND NATURAL GAS PRICE PROJECTIONS**

**Q. What is the basis of the Company's oil and gas commodity price forecasts?**

A. These forecasts were based on monthly NYMEX futures price information and were indicative of future market prices for oil and gas at the time they were prepared.

**Q. What are your underlying assumptions for your fuel oil commodity price projections for 2025?**

A. The price of fuel oil is based on NYMEX West Texas Intermediate ("WTI") crude oil projections and the Company's approximation of the relationship between WTI and fuel oil.

**Q. What are your underlying assumptions for your natural gas commodity projections for 2025?**

A. The price of natural gas for each of the Company's gas plants is based on NYMEX Henry Hub and adjusted to the appropriate city gate gas index and in accordance with the gas management services ("GMS") contract the Company has for each gas generating plant.

**Q. Why does the Company use the NYMEX Henry Hub price as the basis for its gas price projections?**

A. The NYMEX Henry Hub is the pricing point for natural gas futures contracts trade on the NYMEX and is generally accepted to be the primary gas price for the North American natural gas market. There are no similar pricing points projected for the city gates use for index pricing.

**Q. How does the Company determine its projection for the city gates use for index pricing?**

A. The Company determines historical relationships between the respective city gate and the NYMEX Henry Hub based on actual trades. This relationship was then used to adjust the projected NYMEX Henry Hub price to arrive at a projection for the city gate price as shown in Exhibit A-23 (AKR-2).

**Q. Has the Company changed the methodology it employs to develop natural gas and oil price forecasts?**

A. No. The Company has maintained the same methodology it has historically employed to develop its natural gas and oil price forecasts.

## OIL AND NATURAL GAS PROCUREMENT

**Q. What types of fuels are burned at the Company's currently owned oil and natural gas generating plants?**

A. The Zeeland, Jackson, and Covert plants burn natural gas. D.E. Karn ("Karn") Units 3 and 4 burn natural gas and fuel oil.

## KARN PLANT

**Q. What is the source of fuel for Karn Units 3 and 4?**

A. Karn Units 3 and 4 burn natural gas from two pipelines: one source is through a lateral pipeline owned and operated by Phillips 66 ("P66"), formerly DCP Midstream, that is connected to DTE's gas pipeline system in northern Michigan, and the other source is through a direct connection to the Company's natural gas distribution system. In addition, the units can also burn fuel oil.

**Q. How does the Company manage gas and oil purchasing and transportation for Karn Units 3 and 4?**

A. The fuel oil burned at Karn Units 3 and 4 is purchased on an as-needed, spot market basis. The gas for Karn Units 3 and 4 is delivered via the Company distribution system and is purchased on a spot market basis, while the gas delivered via the P66 lateral from DTE's system is purchased under a GMS contract with spot pricing terms.

**Q. Please explain why the oil and natural gas that is purchased for consumption in Karn Units 3 and 4 is purchased on a spot basis, rather than under longer-term contracts like it is for coal.**

A. Much of the reason for doing so lies with the difficulty in accurately predicting the demand for these generally higher-cost units. Unlike the coal units, which are typically operated as baseload units due to their expensive startup and shutdown costs, natural gas fired units have much more flexibility to follow the electric demand and the market price of power and are typically operated as intermediate and peaking units. Therefore, the utilization of these units depend on a number of difficult-to-predict factors, including but not limited to unit availability, competing market power price and availability, weather and its effects on system electric load, electric transmission constraints, and the more volatile nature of the oil and gas markets. In addition to the unpredictable nature of their use, there is also an issue with the limited amount of storage available for natural gas. Contracting for volumes of natural gas which cannot be consumed but are required to be taken can result in increased costs for customers as a result of paying for storage, paying contract penalties, or selling excess quantities at a loss. For these reasons, the Company believes it is prudent to utilize the spot market for fuel to supply these units.

**Q. In the absence of long-term contracts, what does Consumers Energy do to mitigate some of the price volatility of its oil and natural gas purchases for Karn Units 3 and 4?**

A. The ability of Karn Units 3 and 4 to burn either oil or gas or a blend of the two provides flexibility to minimize fuel costs. Unlike gas, which, because of storage limitations, is generally purchased on a spot basis near the time it is consumed, spot purchases of oil are made over time as needed to maintain inventory. Oil can be purchased in varying qualities and prices and stored in tanks at the plant to provide gas and oil blending flexibility. Additionally, the units may also burn 100% gas, though not at full capacity.

**Q. What steps has the Company taken to minimize its natural-gas-related costs, including storage, for these generating units?**

A. The Company periodically performs a Request for Proposal ("RFP") for gas management services, thus making sure the most competitive, viable supplier of these services is utilized. Also, the Company utilizes the provisions contained in its gas transportation agreements and GMS agreements to minimize its natural-gas-related costs. For Karn, this includes monitoring gas usage and market prices during the month and competitively bidding purchases to minimize cost and ensure that month end gas balances are within the specified contract tolerances. It also includes utilizing its available storage (in the form of tolerances allowed by contract) with the Consumers Energy gas utility to purchase lower cost gas during periods of lower gas demand and store such gas ahead of anticipated usage.

**Q. To what extent is the gas storage available on the Consumers Energy gas utility system utilized for the electric utility?**

A. The available storage provided for in the gas transportation agreement for Karn Units 3 and 4 with the gas utility is utilized to store gas purchased when prices are lower. The

Company does not believe it would be prudent to purchase additional storage over and above that amount provided for in the gas transportation agreement for several reasons. These reasons include, but are not limited to: (i) the difficulty in accurately predicting the production on these units and the concern that additional storage would be purchased and not used; (ii) recognition of the potential impacts to Consumers Energy gas customers if storage were used by the electric utility to benefit its electric customers, from both a supply and cost standpoint; and (iii) any gas storage purchased by the electric utility from the gas utility would be provided pursuant to tariffs and would only be available to Karn Units 3 and 4 for a portion of its needs on a seasonal basis.

**ZEELAND PLANT**

**Q. What is the source of fuel for the Zeeland Plant?**

A. The Zeeland Plant is a natural gas-fired facility that is connected to the ANR pipeline system. The Zeeland Plant is connected through a lateral pipeline owned and operated by SEMCO Energy Gas Company ("SEMCO").

**Q. What does Consumers Energy do to assure a reliable and economic supply of fuel for the Zeeland Plant?**

A. Consumers Energy entered into a competitively bid contract with a third-party to act as a GMS agent ("Agent") on behalf of the Company with regard to the gas supply for the Zeeland Plant. The Agent's obligations under the contract include purchasing the gas, transporting the gas utilizing primary and secondary firm transportation from its purchase origin to the point of delivery (the SEMCO interconnection), and storing gas when necessary. Entering into an agreement such as this allows the Company to take advantage of the Agent's diversity of gas purchasing/transportation contracts, gas purchasing experience, as well as the portfolio of arrangements the Agent has with ANR and other pipelines in North America. This experience and expertise enable the Agent to provide transportation and balancing services to the Company more economically than if the Company were required to obtain firm transportation and storage directly from ANR and other pipeline companies. In addition to the transportation that is provided for under this GMS service contract, the Company also has a contract with SEMCO that was assumed by the Company at the time the Zeeland Plant was purchased that provides firm gas transportation from SEMCO's point of interconnection with the ANR pipeline system to the Zeeland Plant.

**Q. How does the GMS contract work?**

A. In addition to procuring the gas commodity and transportation service, the Agent is responsible for providing gas pricing information to the Company which is relied upon by the Company to bid energy from the Zeeland Plant into the Midcontinent Independent System Operator, Inc. ("MISO") energy market. The Agent is also responsible for purchasing gas as directed by the Company in both the day-ahead and the intraday gas markets as MISO accepts offers from the Zeeland Plant in the MISO energy market. In addition, the Agent will provide services to balance gas nominations against dispatch requests from MISO. The pricing of the GMS contract is based on published indices.

**Q. Will the Company pay the Agent a separate amount to transport the gas from the point of origin to the ANR-SEMCO interconnection point?**

A. No. The amount paid to the Agent is an all-inclusive commodity price which includes the price the Agent pays for the physical gas and any costs the Agent may incur to deliver the gas to the ANR-SEMCO interconnection.

**Q. Does the Company pay SEMCO for the use of the lateral pipeline SEMCO owns that connects the Zeeland Plant to the ANR-SEMCO interconnection point?**

A. Yes. The Company pays a fixed annual demand charge for the transportation of up to 16,000 Mcf of gas per day as provided for in the December 17, 1999 Transportation Services Contract (and subsequently amended in 2017) assumed by the Company from the previous owner of the Zeeland Plant at the time the Zeeland Plant was acquired by the Company.

**JACKSON PLANT**

**Q. What is the source of fuel for the Jackson Plant?**

A. The Jackson Plant is a natural gas-fired facility that is connected to the Vector pipeline through a lateral pipeline owned by the Consumers Energy natural gas utility.

**Q. Does the Company pay for the use of the lateral pipeline that connects the Jackson Plant to the Vector interconnection point?**

A. Yes. The Company pays an annual demand charge to the natural gas utility side of the Company as provided for in the March 12, 2002 Transportation Services Contract assumed by the Company from the previous owner of the Jackson Plant which provides firm gas transportation from the point of interconnection with the Vector pipeline to the Jackson Plant.

**Q. Do you believe the demand charges for the Jackson lateral pipeline to be reasonable and prudent though it involves an arrangement with an affiliate?**

A. Yes. The natural gas transportation agreement for the Jackson Plant was initially negotiated and executed as an arm's length transaction between the Company's natural gas utility and a third party under the rules and regulations of Michigan Public Act 9 of 1929.

The agreement was not negotiated between Company affiliates. As the original parties to the agreement were unaffiliated, there was no reason for the Company's natural gas utility to undercharge for the pipeline and natural gas service and there was also no reason for the former plant owner to overpay for the pipeline and natural gas service. When the Company's electric utility later acquired the Jackson Plant from the prior plant owner, the Company's electric utility assumed the prior plant owner's role and obligations under the natural gas transportation agreement. This is analogous to what the Company did with the SEMCO lateral agreement when it purchased the Zeeland Plant.

The Commission initially approved recovery of the costs related to the Company's ownership of the Jackson Plant in the Company's 2014-2015 electric rate case, Case No. U-17335. See MPSC Case No. U-17335, November 19, 2015 Order, page 96. Since the Commission issued its November 19, 2015 Order finding the Jackson Plant capital and Operations and Maintenance costs to be reasonable and prudent for cost recovery purposes, the Company has routinely included the demand charges, as paid by the Company's electric utility to the Company's natural gas utility under the Jackson Plant natural gas transportation agreement, and those charges have been routinely approved for recovery by the Commission as reasonably and prudently incurred power supply costs.

**Q. How does the Company manage gas purchasing and transportation for the Jackson Plant?**

A. Similar to the Zeeland Plant, the Company entered into a competitively bid GMS contract with a third-party agent to manage the gas supply for the Jackson Plant, whose responsibility is to provide a firm supply of gas at an all-inclusive delivered price to the plant's interconnection point with Vector.

**COVERT PLANT**

**Q. What is the source of fuel for the Covert Plant?**

A. The Covert Plant is directly connected to the ANR natural gas interstate pipeline system.

**Q. How does the Company supply natural gas to the facility?**

A. Similar to the Zeeland and Jackson plants, the Company entered into a competitively bid GMS contract with a third-party agent to manage the gas supply for the Covert Plant, whose responsibility is to provide a firm supply of gas at an all-inclusive delivered price to the plant's interconnection point with ANR.

**GAS MANAGEMENT SERVICE AGREEMENT**

**Q. Does the method for managing the gas supplies for the Zeeland, Jackson, Covert and Karn plants using an Agent to ensure a reliable and reasonably priced gas supply to these facilities?**

A. Yes. The requirements for the Agents to hold the necessary firm transportation assets with the pipeline companies to deliver the gas to the plants' delivery point (or utilize firm transportation assets held by the Company) and methods previously described for the pricing of the gas ensures these facilities are reliable and competitive participants in the MISO energy market.

**Q. When do the current GMS agreements for the Company's natural gas plants expire?**

A. The current GMS contracts expire on October 31, 2024. The Company has secured proposals and is in the process of negotiating new GMS agreements for all four natural gas generating plants that will be effective November 1, 2024, and cover the 2025 PSCR Plan year.

**Q. What natural gas pricing has been assumed in this PSCR Plan for the new GMS agreements?**

A. Because of the relative stability we have seen in the various agents' delivered cost pricing relative to the city gate indices, we have assumed the new agreements will have the same cost structure to the existing agreements and this has been reflected in the Company's price projections.

<u>**PSCR CONTINGENCY MECHANISM**</u>

**Q. What is the Company's proposal for the PSCR contingency mechanism?**

A. As discussed in more detail by Company witness Andrew G. Volansky, the Company is proposing a PSCR contingency mechanism. The PSCR contingency mechanism would allow for upward adjustments in the PSCR factor based upon increases in the 12-month forward NYMEX average natural gas price.

**Q. Why was NYMEX chosen as the index on which to base the PSCR contingency mechanism?**

A. There is a direct relationship between natural gas costs and Locational Marginal Prices ("LMP") and the resulting total PSCR costs. Because of the volatility of natural gas prices, there can be significant differences in PSCR costs from the time the PSCR Plan was filed and what is actually incurred.

**Q. What is the purpose of the PSCR contingency mechanism?**

A. The purpose of the PSCR contingency mechanism is to allow for increases in the maximum PSCR factor based upon 12-month forward NYMEX average natural gas prices which exceed the NYMEX natural gas prices which were the basis for the PSCR Plan filing. The ability to increase the maximum PSCR factor based upon an increase in natural gas prices would allow the Company to recover PSCR costs in a timely manner and to collect that recovery from the PSCR customers that received the energy which was generated at an increased natural gas expense.

**Q. How would the proposed PSCR contingency mechanism operate?**

A. The Company has proposed to allow for defined increases in the maximum PSCR factor based upon increases in the 12-month forward NYMEX average gas price in increments of $0.25/MMBtu up to a maximum increase of $4.00/MMBtu. Company witness Joshua W. Hahn has modeled the total 2024 PSCR Plan costs based upon his natural gas price increment. Company witness Volansky has prepared an adjusted maximum PSCR factor for each of these $0.25/MMBtu natural gas price increases up to $4.00/MMBtu.

**Q. Does this complete your prepared direct testimony?**

A. Yes, it does.

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**EXHIBITS**

**OF**

**ANGELA K. RISSMAN**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-22 (AKR-1)

Witness: AKRissman
Date: September 2024

## 2025 Coal Contract & Purchase Data

| Line No. | (a) Supplier Contract No | (b) Coal Type | (c) Contract Execution Date | (d) Contract Start Date | (e) Contract End Date | (f) Volume (Tons) | (g) Price ($/Ton) |
|---|---|---|---|---|---|---|---|
| 1 | 393 | Western | 11/3/2023 | 1/1/2025 | 12/31/2025 | 156,000 | $14.500 |
| 2 | | 2025 UNCOMMITTED AS OF 2025 PSCR PLAN CASE | | | | 1,501,938 | |
| 3 | | | | | **2025 Total** | **1,657,938** | |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-23 (AKR-2)

Witness: AKRissman
Date: September 2024

**2025 Forecasted Natural Gas Prices and 2024 Comparison of Forecasted vs. Actual Natural Gas Prices**

| Line | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2025 Forecasted Prices** | | | | | | | | | | | | | |
| 1 | **Month** | **Jan-25** | **Feb-25** | **Mar-25** | **Apr-25** | **May-25** | **Jun-25** | **Jul-25** | **Aug-25** | **Sep-25** | **Oct-25** | **Nov-25** | **Dec-25** | **Average** |
| 2 | 2024 Plan Henry Hub Forecast | $4.55 | $4.43 | $4.04 | $3.57 | $3.55 | $3.66 | $3.77 | $3.82 | $3.79 | $3.86 | $4.25 | $4.68 | $4.00 |
| 3 | 2025 Plan Henry Hub Forecast | $3.38 | $3.24 | $2.93 | $2.80 | $2.85 | $3.01 | $3.18 | $3.21 | $3.18 | $3.25 | $3.53 | $3.95 | $3.21 |
| 4 | CE-Henry Hub Basis | ($0.16) | ($0.16) | ($0.16) | ($0.39) | ($0.39) | ($0.25) | ($0.25) | ($0.25) | ($0.39) | ($0.39) | ($0.39) | ($0.16) | ($0.28) |
| 5 | Consumers Citygate | $3.21 | $3.08 | $2.76 | $2.41 | $2.46 | $2.76 | $2.92 | $2.96 | $2.79 | $2.86 | $3.14 | $3.78 | $2.93 |
| 6 | Michcon-Henry Hub Basis | ($0.18) | ($0.18) | ($0.18) | ($0.41) | ($0.41) | ($0.27) | ($0.27) | ($0.27) | ($0.41) | ($0.41) | ($0.41) | ($0.18) | ($0.30) |
| 7 | Michcon Citygate | $3.19 | $3.05 | $2.74 | $2.39 | $2.44 | $2.74 | $2.90 | $2.94 | $2.77 | $2.84 | $3.12 | $3.76 | $2.91 |
| 8 | Dawn-Henry Hub Basis | ($0.08) | ($0.08) | ($0.08) | ($0.39) | ($0.39) | ($0.28) | ($0.28) | ($0.28) | ($0.39) | ($0.39) | ($0.39) | ($0.08) | ($0.26) |
| 9 | Dawn Ontario | $3.30 | $3.16 | $2.84 | $2.41 | $2.46 | $2.73 | $2.90 | $2.93 | $2.79 | $2.86 | $3.14 | $3.86 | $2.95 |
| | | | | | | | | | | | | | | |
| 10 | **2024 Forecast vs. Actual** | | | | | | | | | | | | | |
| 11 | **Month** | **Jan-24** | **Feb-24** | **Mar-24** | **Apr-24** | **May-24** | **Jun-24** | **Jul-24** | **Aug-24** | **Sep-24** | **Oct-24** | **Nov-24** | **Dec-24** | **Average**[1] |
| 12 | 2024 Plan Henry Hub Forecast | $3.88 | $3.80 | $3.49 | $3.15 | $3.14 | $3.24 | $3.35 | $3.38 | $3.36 | $3.45 | $3.83 | $4.28 | $3.43 |
| 13 | 2024 Henry Hub Actuals | $3.20 | $1.75 | $1.50 | $1.59 | $2.12 | $2.50 | $2.10 | $1.98 | | | | | $2.09 |

[1] represents an eight month average of January - August.

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<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**DIRECT TESTIMONY**

**OF**

**BETH A. SKOWRONSKI**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Beth A. Skowronski, 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 the Manager of Supply Contracts in the Contracts and Settlements Section of the Electric Supply Operations Department.

**<u>QUALIFICATIONS</u>**

**Q. Please describe your educational background and business experience.**

A. I received a Bachelor of Business Administration from Siena Heights University in 2013. I also hold a State of Michigan Real Estate Salesperson's license. I started my career at Consumers Energy in 2006 in Customer Service in various roles with increasing responsibilities in Revenue Recovery, Real Estate, and Distribution Operations. In 2015, I accepted a position in Contracts and Settlements, where my direct responsibilities included administering Power Purchase Agreements ("PPAs") and issuing solicitations for energy and capacity.

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

A. Yes. I provided testimony in:

- MPSC Case No. U-21666 (direct), the Company's request for approval of a bilateral capacity transaction;
- MPSC Case No. U-21258 (direct), the Company's 2023 Power Supply Cost Recovery ("PSCR") Reconciliation Case, regarding purchased power supply costs;

- MPSC Case No. U-20149 (rebuttal), in the Company's 2022 PSCR Reconciliation Case, regarding purchased power supply costs;
- MPSC Case No. U-20496 (direct), the Company's request for approval of an amended PPA;
- MPSC Case No. U-21090 (direct), the Company's request for approval of an Integrated Resource Plan ("IRP") under MCL 460.6t, certain accounting approvals, and for other relief;
- MPSC Case No. U-20165 (direct), the Company's multiple requests for approval of new solar PPAs and Build Transfer Agreements ("BTAs") obtained through competitive solicitations;
- MPSC Case No. U-20165 (direct), the Company's requests for approval to reset the Company's Public Utility Regulatory Policies Act of 1978 ("PURPA") avoided cost rates and for approval of new solar PPAs obtained through a competitive solicitation;
- MPSC Case No. U-20604 (direct), the Company's request for approval of new PPAs based on the Company's avoided costs;
- MPSC Case No. U-20604 (direct), the Company's request for approval of amendments to PPAs;
- MPSC Case No. U-20833 (direct), the Company's request for approval of new PPAs based on the Company's PURPA full avoided cost rates;
- MPSC Case No. U-18425 (direct), the Company's request for approval of new PPAs based on the Company's PURPA full avoided cost rates; and
- MPSC Case No. U-20496 (direct), the Company's request for approval of PPA amendments.

**<u>PURPOSE OF DIRECT TESTIMONY</u>**

**Q. What is the purpose of your direct testimony**?

A. My direct testimony will address: (i) the PPA resources included in this PSCR Plan that have not been previously approved by the Commission; (ii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iii) the Company's Blackstart Resource Agreement; and (iv) PSCR treatment of MISO revenue and expenses.

**Q. Are you sponsoring any exhibits?**

A. Yes. I am sponsoring the following exhibit:

| | |
|---|---|
| Exhibit A-24 (BAS-1) | New and Amended PPAs not Previously Included in the Company's PSCR Plan. |

**Q. Was this exhibit prepared by you or under your direct supervision?**

A. Yes.

**<u>PPA RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION</u>**

**Q. Are there any PPA resources included in this PSCR Plan that have not been previously approved by the Commission?**

A. Yes.

**Q. What resources have been included in this PSCR Plan that have not been previously approved by the Commission?**

A. There are several resources included in this PSCR Plan that have not been previously approved by the Commission. They can be categorized into the following groups:

- PURPA Obligations;
- New Solar Facilities;
- One-Time Solicitation Resources; and
- Short-Term Bilateral Capacity Transactions.

**Q. Please explain the PPAs, not previously approved by the Commission, that are included in this PSCR filing associated with the Company's PURPA obligation.**

A. The Company has several contracts in place with facilities that have, or are expected to, meet the requirements of Qualifying Facilities ("QFs"),[1] in accordance with PURPA, that

[1] Either a qualifying small power production facility or a qualifying cogeneration facility that meets certain size, fuel, and/or efficiency standards.

will terminate during the time period from 2025 to 2029 as discussed later in my direct testimony. The Company forecasts that at the end of the current contract terms, these facilities will execute new PURPA-based agreements at the PURPA rates established in Case No. U-18090, Case No. U-20165, and Case No. U-21090 as applicable.

**Q. Please explain the PPAs, not previously approved by the Commission, that are included in this PSCR filing associated with new solar facilities.**

A. On June 7, 2019 and June 23, 2022, the Commission's orders in Case Nos. U-20165 and U-21090 approved the settlement agreements in the Company's IRPs. The IRPs include the addition of new solar resources to the Company's portfolio of supply assets to be acquired through a competitive solicitation process. In accordance with the settlement agreements, the Company expects that 50% of the new solar assets will be sourced through PPAs and the other 50% will be Company-owned solar projects. PURPA QFs of any technology up to the Company's must-purchase obligation under PURPA will be eligible to participate in the annual competitive solicitations as well. The Company estimates that the rates paid under the new PPAs will be similar to the rate included in the recently executed PPA with Freshwater Solar, LLC. Therefore, the Company has forecasted expenses for the new IRP solar PPAs at the Freshwater Solar, LLC rate, however, the actual rates will be determined in the annual competitive solicitations.

**Q. Please explain the IRP competitive solicitations.**

A. The details for administering the competitive solicitations are included in the IRP settlement agreements in Case Nos. U-20165 and U-21090. The Company utilizes an Independent Administrator to conduct the solicitations, complete the proposal evaluations, and provide a blind ranking of projects to the Company for selection. The Company has included the costs associated with the service agreement with the Independent Administrator in this PSCR Plan case on Exhibit A-7 (JWH-1), page 1, line 33.

**Q. Are there any additional contracts for energy and capacity included in this PSCR Plan case that were not previously included in the 2024 PSCR Plan?**

A. Yes. The contracts that were not previously included in the 2024 PSCR Plan are listed in Exhibit A-24 (BAS-1). Column (c) shows the fuel source of the PPA. Column (a) details the plant that is supplying energy and capacity for the PPA. Columns (d) and (e) list the MPSC case number associated with the Company's application for approval of each PPA and the date of the MPSC order approving the application, respectively. Additionally, the Company has amended PPAs since the filing of the 2024 PSCR Plan. These amendments are also shown in Exhibit A-24 (BAS-1) and are denoted in column (b).

**Q. Please explain the PPAs, not previously approved by the Commission, that are included in this PSCR filing associated with the Company's One-Time Solicitation.**

A. On June 23, 2022, the Commission's Order in Case No. U-21090 approved the Settlement Agreement in the Company's IRP. In accordance with this Settlement Agreement, the Company planned to source 500 Zonal Resource Credits ("ZRCs") through PPAs for dispatchable, non-intermittent generation and 200 ZRCs through PPAs for intermittent resources and dispatchable, non-intermittent clean resources (including storage) through a competitive solicitation process. Although the One-Time Solicitation for 500 ZRCs of PPAs for dispatchable, non-intermittent generation did not result in any executed PPAs, and respondents were released from consideration, the One-Time Solicitation for 200 ZRCs resulted in several executed or soon-to-be executed PPAs. The Company received MPSC approval for the 100 MW Battery Energy Storage PPA with Tibbits Energy

Storage, LLC on April 11, 2024 and the 200 MW Battery Energy Storage PPA with Century Oaks Energy Storage, LLC on August 22, 2024. A third project, a 100 MW Battery Energy Storage PPA with Voyager Energy Storage, LLC, has also been submitted (on September 27, 2024) for MPSC approval. The Company awarded additional contracts as part of the 200 ZRC tranche because the contracts were reasonably priced, included good terms, and allowed the Company to backfill for the unfilled 500 ZRC tranche.

**Q. Please explain the Company's One-Time Solicitation.**

A. The details for administering the One-Time Solicitation are included in the Commission's June 23, 2022 Order in Case No. U-21090. The IRP includes the addition of new PPA resources to the Company's portfolio of supply assets to be acquired through a competitive solicitation process. The Company utilizes an Independent Administrator to conduct the solicitation, complete the proposal evaluations, and provide a recommendation to the Company for selection. The Company has included the cost associated with the service agreement with the Independent Administrator in this PSCR Plan case on Exhibit A-7 (JWH-1), page 1, line 33.

**Q. Please explain the contracts, not previously approved by the Commission, that are included in this PSCR filing associated with short-term bilateral capacity transactions.**

A. In 2023, the Company entered into a short-term bilateral capacity transaction for planning years 2025 through 2027. The Company sought MPSC approval of this transaction in a separate docket, Case No U-21666, which is pending. In 2024, the Company entered an additional short-term bilateral capacity transaction resulting from a Reverse Capacity Auction for capacity ZRC's supporting planning years 2025 through 2026. The Company anticipates seeking MPSC approval of this transaction in a separate docket while this case is ongoing.

**BLACK START SERVICE**

**Q. Please explain what the term "Black Start" means.**

A. Normally, electric generating units rely on external power supply to initiate operations. Black Start service refers to the process of restoring a generation resource without relying on the external electric power transmission network.

**Q. Will the Company have any generation resources designated for Black Start service in 2025?**

A. Yes. Ludington Pumped Storage Units 2, 3, and 5 are maintained in accordance with the July 1, 2013 Blackstart Resource Agreement with Michigan Electric Transmission Company, LLC ("METC"), as amended, to be available for Black Start service as part of METC's system restoration plan. The forecast of costs associated with Black Start service is in this PSCR Plan case on Exhibit A-1 (DSA-1), page 1, line 29.

**TERMINATION OF COMMISSION-APPROVED PPAS**

**Q. Does the Company have any PPAs, previously approved by the Commission, that have terminated or will terminate in 2025?**

A. Yes. In addition to the PPAs previously discussed in my testimony, the following PPAs will, or are expected to be, terminate(d) by the end of 2025:

- The Agreement with Addle Solar, LLC for the output of the Addle Solar Plant was terminated on May 15, 2024.
- The Agreement with Olivier Solar, LLC for the output of the Olivier Solar Plant was terminated on May 15, 2024.
- The Agreement with Puck Solar, LLC for the output of the Puck Solar Plant was terminated on May 15, 2024.

- The Agreement with Sunbelievable Solar, LLC for the output of the Sunbelievable Solar Plant was terminated on May 15, 2024.
- The Agreement with STS Hydropower, LLC for the output of the Ada Hydro Plant will terminate on May 31, 2025.
- The Agreement with Thorn Lake Solar, LLC for the output of the Thorn Lake Plant was terminated on August 7, 2024.
- The Agreement with Tondu Energy Systems, Inc. for the output of the TES Filer City Station LP will terminate on June 16, 2025.

**Q. Please discuss the Company's obligations to purchase energy and capacity from QFs.**

A. Under PURPA, as well as the Federal Energy Regulatory Commission ("FERC") Orders implementing PURPA and the 2021 IRP Settlement Agreement in Case No. U-21090, the Company is obligated to buy the energy and, if applicable, capacity (*i.e.*, the Company's avoided cost) through PURPA contracts with small power production (*i.e.*, renewable) QFs up to 5 MW in size and co-generation facilities up to 20 MW in size.

**Q. Who has the authority to determine when there is a must-purchase obligation with QFs?**

A. The MPSC has the authority to determine when the Company must purchase from QFs and the price the Company must pay for energy and, if applicable, capacity (*i.e.*, the Company's avoided cost). The Commission's May 31, 2017 Order in Case No. U-18090 directed the Company to pay the full avoided cost (energy and capacity) to QFs with expired PURPA-based PPAs regardless of whether the capacity is needed. The Commission's June 23, 2022 Order Approving Settlement Agreement in Case No. U-21090 approved the Company's IRP Settlement Agreement, which maintains that current existing QFs with a full avoided cost PURPA-based PPA with the Company, as of January 1, 2019, shall receive new PPAs based on the Company's full avoided cost rates at the time of PPA expiration, regardless of whether the capacity is needed.[2] Therefore, the Company expects the majority of eligible QFs to execute new PURPA-based agreements at the applicable full avoided cost rate once their existing PURPA-based PPAs expire. The Commission's June 23, 2022, Order Approving Settlement Agreement in Case No. U-21090 also maintains that QFs 150 kW and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs. When the Company does not have a PURPA capacity need, QFs above 150 kW, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates.

**MISO ENERGY MARKETS**

**Q. Regarding serving Consumers Energy's bundled load, will all the charges incurred, and revenues received by Consumers Energy under MISO's Transmission, Energy, and Operating Reserve Markets Tariff be included in net PSCR costs to be recovered from Consumers Energy's PSCR customers in 2025?**

A. Yes. All the expenses incurred with MISO and all of the revenues received from MISO to the extent the revenues received were from the output of jurisdictional facilities sold to MISO, are expected to be included in PSCR costs reconciled in the Company's 2025 PSCR Reconciliation case. As with prior PSCR Plan filings, to the extent that the revenue is provided to offset PSCR costs incurred, the Company plans to credit that revenue against PSCR expense. Consumers Energy will include all MISO settled charges incurred and revenues received during the year in the 2025 PSCR Reconciliation case. In this filing,

[2] The Case No. U-21090 IRP Settlement Agreement defines "QF" as "Qualifying Facilities which the Company has a legal obligation to purchase from under PURPA."

MISO revenues and expenditures are forecasted and presented in the direct testimony and exhibits of Company witnesses Daniel S. Alfred and Joshua W. Hahn.

**<u>SUMMARY</u>**

**Q. Please summarize your direct testimony.**

A. My direct testimony explains: (i) the PPA resources included in this PSCR Plan that have not been previously approved by the Commission; (ii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iii) the Company's Blackstart Resource Agreement; and (iv) PSCR treatment of MISO revenue and expenses.

**Q. Does this complete your direct testimony?**

A. Yes, it does.

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<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**EXHIBIT**

**OF**

**BETH A. SKOWRONSKI**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
New and Amended PPAs not Previously Included in the Company's PSCR Plan

Case No.: U-21592
Exhibit No.: A-24 (BAS-1)
Page: 1 of 1
Witness: BASkowronski
Date: September 2024

| line | (a) Counterparty | (b) New PPA/Amendment | (c) Fuel | (d) MPSC Case No. | (e) MPSC Approval Date |
|---|---|---|---|---|---|
| 1 | Century Oaks Energy Storage | New PPA | Battery | U-21090 | 8/22/2024 |
| 2 | STS Hydropower-Ada | New PPA | Hydro | U-18425 | 8/22/2024 |
| 3 | Dustin Damon | New PPA | Solar PV | n/a | n/a |
| 4 | Heartwood Solar | Amendment | Solar PV | U-20165 | 4/25/2024 |
| 5 | Bingham Solar | Amendment | Solar PV | n/a | n/a |
| 6 | Temperance Solar | Amendment | Solar PV | n/a | n/a |
| 7 | Jackson County | Amendment 2 | Solar PV | U-20165 | 12/21/2023 |
| 8 | Tibbits Energy Solar, LLC | New PPA | Battery | U-21090 | 4/11/2024 |
| 9 | Michigan Power Limited Partnership | Amendment | Nat Gas | U-21507 | 3/15/2024 |
| 10 | Jackson County | Amendment 3 | Solar PV | U-20165 | Pending |
| 11 | Joe Kittle | New PPA | Solar PV | n/a | n/a |
| 12 | Hogan Dairy | New PPA | Solar PV | n/a | n/a |
| 13 | Freshwater Solar, LLC | New PPA | Solar PV | U-20165 | 3/15/2024 |
| 14 | Brook View Dairy | New PPA | Anaerobic Digester | n/a | n/a |
| 15 | Scenic View Dairy | New PPA | Anaerobic Digester | n/a | n/a |
| 16 | Hearty Fresh Inc. | New PPA | Solar PV | n/a | n/a |
| 17 | Cascade Engineering, Inc | New PPA | Solar PV | n/a | n/a |
| 18 | Prairie View Dairy, LLC | New PPA | Solar PV | n/a | n/a |
| 18 | Voyager Energy Solar, LLC | New PPA | Battery | U-21090 | Pending |

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 | ) | Case No. U-21592 |
| cost recovery plan for the 12 months | ) | |
| ending December 31, 2025 | ) | |
| | ) | |

**DIRECT TESTIMONY**

**OF**

**ANDREW G. VOLANSKY**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

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

A. My name is Andrew G. Volansky, 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 a Senior Rate Analyst II in the Revenue Requirement and Analysis Section of the Rates and Regulation Department.

**Q. Please state your educational background.**

A. I graduated from Wayne State University in 1992 with a Bachelor of Science Degree, majoring in Psychology and in 2001 with a Bachelor of Business Administration Degree, majoring in Accounting. I am also a Certified Public Accountant registered in the state of Michigan.

**Q. Please describe your business experience.**

A. After receiving my accounting degree in 2001, I worked as a staff auditor at Arthur Andersen LLP (2001-2002) and George Johnson and Company (2002-2003) working on financial audits, compliance audits, and income tax returns. In 2004, I joined Consumers Energy as an Accounting Analyst in the Technical Accounting and External Financial Reporting Department and was promoted throughout the years to a Senior Accounting Analyst. In 2016, I accepted the position of Senior Rate Analyst II in the Revenue Requirement Section of the Rates and Regulation Department.

**Q. What are your responsibilities as Senior Rate Analyst?**

A. My responsibilities include assisting in the development of analyses related to the Company's revenue requirements and the preparation of electric and gas rate case filings at the Michigan Public Service Commission ("MPSC" or the "Commission"). I am also responsible for forecasting the Power Supply Cost Recovery ("PSCR") Factor on a monthly basis.

**Q. Have you previously testified or sponsored testimony in any regulatory proceedings?**

A. Yes, I sponsored testimony in the following cases:

Case No. U-18402 – 2018 PSCR Plan Case;
Case No. U-18424 – Gas Rate Case Filing;
Case No. U-20219 – 2019 PSCR Plan Case;
Case No. U-20525 – 2020 PSCR Plan Case;
Case No. U-20618 – Mid-Michigan Pipeline Act 9 Filing;
Case No. U-20802 – 2021 PSCR Plan Case;
Case No. U-21080 – 2020 Demand Response Reconciliation;
Case No. U-21048 – 2022 PSCR Plan Case;
Case No. U-21233 – 2021 Demand Response Reconciliation;
Case No. U-21257 – 2023 PSCR Plan Case;
Case No. U-21410 – 2022 Demand Response Reconciliation;
Case No. U-21423 – 2024 PSCR Plan Case; and
Case No. U-21510 – Oakland Resilience Interconnect.

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

A. The purpose of my testimony is to present the calculation of the 2025 PSCR Factor and present the proposed contingency factors for the 2025 plan years.

**Q. Are you sponsoring any exhibits in connection with your testimony?**

A. Yes, I am sponsoring the following exhibits:

Exhibit A-25 (AGV-1) Calculation of 2025 PSCR Factor;

| | |
|---|---|
| Exhibit A-26 (AGV-2) | Tariff Sheet D-6.00 PSCR and Factors; and |
| Exhibit A-27 (AGV-3) | Tariff Sheets D-6.10 – D-6.20 Monthly PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism. |

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

A. Yes.

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

A. Section I provides the 2025 PSCR Ceiling Factor calculation. In Section II, I discuss the proposed PSCR Ceiling Price Adjustment (Contingency) Mechanism and the Contingent PSCR Ceiling Factors. In Section III, I discuss the Billed PSCR Factor.

## I. <u>THE 2025 PSCR CEILING FACTOR CALCULATION</u>

**Q. Please describe Exhibit A-25 (AGV-1).**

A. Exhibit A-25 (AGV-1) shows the calculation of the 2025 PSCR Ceiling Factor. The 2025 PSCR Ceiling Factor is calculated by adding line 1, Total Power Supply Cost less Long Term Industrial Load Retention Rate ("LTILRR") Payments provided by Company witness Joshua W. Hahn to line 2, the 2025 allocated portion of the 2022 under recovery, to determine line 3, the 2025 PSCR Factor Costs. The 2025 PSCR Factor Costs is divided by line 4, Total System Requirements less LTILRR (measured in units of kilowatt hours ("kWh")), provided by Company witness Eugène M.J.A. Breuring, to determine the average cost per kWh of requirements on line 5. From this quotient is subtracted by the Base Recovery Factor (shown on line 6) collected through the standard tariffs as approved by the Commission. This remaining cost per kWh amount of $0.00845, set forth on line 7, is multiplied by the Line and Transformation Loss Factor on line 8 to determine the 2025 per kWh PSCR Ceiling Factor of $0.00909 at sales, shown on line 9.

**Q. Please explain the source of the 2025 allocated portion of the 2022 under-recovery.**

A. During the 2022 PSCR plan year, Consumers Energy experienced a significant under-recovery of its PSCR costs due primarily to dramatic increases in the price of natural gas. In Case No. U-21257, the Company's 2023 PSCR plan case, Consumers Energy initially included the entire forecasted amount of the 2022 under-recovery (approximately $450 million) for collection through the 2023 PSCR factor. However, in January 2023, the Company filed a motion seeking Commission approval to spread the 2022 under-recovery amount across a three-year period (2023, 2024, and 2025) in roughly equal amounts in order to ease the rate burden on customers. All parties to Case No. U-21257 filed statements of non-objection, and the Commission approved the plan in an order issued February 23, 2023. The 2025 allocated portion of the 2022 under-recovery, shown on line 2 of Exhibit A-25 (AGV-1), is the third increment of the three-year recovery plan for the 2022 PSCR under-recovery as approved in the Commission's February 23, 2023 and August 30, 2023 orders in Case No. U-21257.

**Q. Has the actual amount of the 2022 under-recovery been determined yet?**

A. No. The Company filed its 2022 PSCR reconciliation case, Case No. U-21049, on March 31, 2023. The Company proposed a 2022 under-recovery amount slightly lower than the $450 million originally forecasted in Case No. U-21257. A Commission order determining the final amount of the 2022 under-recovery has not been issued. While the final actual amount of the 2022 under-recovery may be subject to change, the 2025 increment of the 2022 under-recovery approved by the Commission in Case No. U-21257 remains reasonable for inclusion in the 2025 PSCR factor calculation.

**II. Proposed PSCR Ceiling Price Adjustment (Contingency) Mechanism and the Contingent PSCR Ceiling Factors**

**Q. Please describe Exhibit A-26 (AGV-2).**

A. Exhibit A-26 (AGV-2) shows the proposed tariff sheet number D-6.00. This tariff sheet lists the Maximum Allowable PSCR Factor and the Actual PSCR Factor Billed by billing month.

**Q. Please describe Exhibit A-27 (AGV-3).**

A. Exhibit A-27 (AGV-3) provides the Company's proposed tariff sheets numbered D-6.10 through D-6.20. These tariff sheets describe the Proposed PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism and list the Contingent PSCR Ceiling Factors.

**Q. What is the PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism?**

A. The PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism allows the Company to increase the Maximum Allowable PSCR Factor above the PSCR Plan Ceiling Factor, under certain circumstances, in response to changes in New York Mercantile Exchange ("NYMEX"). The Maximum Allowable PSCR Factor cannot be lowered below the PSCR Plan Ceiling Factor. The review and the change implementation process are described on Exhibit A-27 (AGV-3). The PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism described on Exhibit A-27 (AGV-3) allows an increase above the PSCR Plan Ceiling Factor to reflect any increases in NYMEX prices if the updated 12-month forecast is greater than the 12-month forecast that was used in developing the PSCR Plan Ceiling Factor.

**Q. How is the amount of the Contingent PSCR Ceiling Factor determined?**

A. A comparison is made monthly between the updated 12-month average NYMEX Price forecast, determined as described on tariff sheet D-6.10, and the 12-month average

NYMEX Price Forecast used in developing the PSCR Plan Ceiling Factor. The Contingent PSCR Ceiling Factors shown on tariff sheet D-6.20 are based on the new forecasted Total Power Supply Costs less LTILRR Payments that would be incurred under the updated 12-month NYMEX Price Forecast. In order to simplify the tariff sheet, changes in the 12-month Plan NYMEX Forecast for the PSCR period are recognized in $0.25 increments. If the amount of increase in the NYMEX Forecast is less than $0.25 the Contingent PSCR Ceiling Factor is the same as the PSCR Plan Ceiling Factor. The adjustment mechanism has a $4.00 ceiling on increases in the NYMEX Price Forecast.

## III. <u>THE BILLED PSCR FACTOR</u>

**Q. Is there a difference between the PSCR Factor calculated in this proceeding and the actual PSCR Factor charged throughout the year?**

A. Yes. The PSCR Factor calculated in this proceeding sets the maximum factor that the Company is authorized to charge throughout the year. The actual PSCR Factor can be at or below this maximum factor. The actual PSCR Factor is determined each month based on the Company's latest forecast of sales and PSCR costs and available actual sales and PSCR cost information. Each month, using this information, the Company attempts to implement future monthly PSCR factors that will result in an annual zero over- or under-recovery.

**Q. What is the purpose of this policy?**

A. The Company's policy is intended to match costs with the customers who cause the Company to incur those costs. While it is unlikely that the Company will succeed in exactly matching costs with customers who incurred the costs, the monthly calculations described above attempt to minimize any over- or under-recovery for the PSCR Plan year.

**Q. What prevents the Company from charging a higher factor, and, in fact, significantly over collecting its PSCR costs?**

A. Any amounts over collected are subject to refund with interest at the Company's authorized return on equity, which is currently 9.90%.

**Q. Does this conclude your direct testimony?**

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**EXHIBITS**

**OF**

**ANDREW G. VOLANSKY**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

September 2024

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company

Case No.: U-21592
Exhibit No.: A-25 (AGV-1)
Page: 1 of 1
Witness: AGVolansky
Date: September 2024

## Calculation of 2025 PSCR Factor

| Line | | | |
|---|---|---|---|
| 1 | Total Power Supply Costs less LTILRR Payments[1] | $ | 1,925,308,178 |
| 2 | Projected 2022 Under Recovery[2] | $ | 149,692,110 |
| 3 | 2025 PSCR Factor Costs (Line 1 + Line 2) | $ | 2,075,000,287 |
| 4 | Total System Requirements less LTILRR in kWh[3] | | 32,345,633,814 |
| | **Jurisdictional Factor Calculation** | | |
| 5 | Average Cost at Requirements (Line 3 / Line 4) | $ | 0.06415 |
| 6 | Less: Base Recovery Factor[4] | $ | 0.05570 |
| 7 | Remaining Cost per kWh (Line 5 - Line 6) | $ | 0.00845 |
| 8 | Line & Transformation Loss Factor[4] | | 1.07573 |
| 9 | 2025 PSCR Base Ceiling Factor at Sales (Line 7 x Line 8) | $ | 0.00909 |

Sources:
[1]Exhibit A-7 (JWH-1), Page 1, Line 45
[2]Per U-21257 Order approving settlement agreement
[3]WP-EMB-1
[4]Per Rule C-8, Section B(1) of Company Tariffs

**M.P.S.C. No. 14 – Electric** **Sheet No. D-6.00**
**Consumers Energy Company**

## POWER SUPPLY COST RECOVERY (PSCR) FACTORS

| Billing Months<br>Year ~~2023~~ *2024* | Maximum Allowable Factor<br>$/kWh | Actual Factor Billed<br>$/kWh |
|---|---|---|
| January | $~~0.02700~~ *0.00877* | $~~0.02209~~ *0.00648* |
| February | ~~0.02700~~ *0.00877* | ~~0.01845~~ *0.00357* |
| March | ~~0.01727~~ *0.00877* | ~~0.00161~~ *0.00276* |
| April | ~~0.01727~~ *0.00877* | ~~0.00232~~ *0.00183* |
| May | ~~0.01727~~ *0.00877* | ~~(0.00105)~~ *0.00254* |
| June | ~~0.01727~~ *0.00877* | ~~(0.00038)~~ *0.00304* |
| July | ~~0.01727~~ *0.00877* | ~~0.00044~~ *0.00617* |
| August | ~~0.01727~~ *0.00877* | ~~0.00138~~ *0.00456* |
| September | ~~0.01727~~ *0.00877* | ~~0.00156~~ *(0.00117)* |
| October | ~~0.01727~~ *0.00877* | ~~0.00168~~ *(0.00174)* |
| November | ~~0.01727~~ *0.00877* | ~~0.00247~~ |
| December | ~~0.01727~~ *0.00877* | ~~0.00897~~ |

| Billing Months<br>Year ~~2024~~ *2025* | Maximum Allowable Factor<br>$/kWh | Actual Factor Billed<br>$/kWh |
|---|---|---|
| January | $~~0.00877~~ *0.00909* | $~~0.00648~~ |
| February | ~~0.00877~~ *0.00909* | ~~0.00357~~ |
| March | ~~0.00877~~ *0.00909* | ~~0.00276~~ |
| April | ~~0.00877~~ *0.00909* | ~~0.00183~~ |
| May | ~~0.00877~~ *0.00909* | ~~0.00254~~ |
| June | ~~0.00877~~ *0.00909* | ~~0.00304~~ |
| July | ~~0.00877~~ *0.00909* | ~~0.00617~~ |
| August | ~~0.00877~~ *0.00909* | ~~0.00456~~ |
| September | ~~0.00877~~ *0.00909* | ~~(0.00117)~~ |
| October | ~~0.00877~~ *0.00909* | ~~(0.00174)~~ |
| November | *0.00909* | |
| December | *0.00909* | |

The listed monthly power supply cost recovery factors are authorized pursuant to Rule C8., Power Supply Cost Recovery (PSCR) Clause. *The Maximum Allowable PSCR Factors shown above are subject to adjustment pursuant to the PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism beginning on Sheet No. D-6.10 for the 2025 Plan Year. Sheet No. D-6.00 will be updated if adjustments are made pursuant to this mechanism. The Commission is authorized to approve PSCR ceiling price adjustments contingent on future events pursuant to Section 6j(6) of 1982 PA 304, as amended.*

*The Maximum Allowable PSCR Factors, adjusted pursuant to the PSCR Factor Ceiling Price Adjustment (Contingency) Mechanism beginning on Sheet No. D-6.10, are the maximum rates the Company may charge. The actual PSCR Factor Billing in any month may be less than the Maximum Allowable PSCR Factor.*

*The Company has filed for Maximum Allowable PSCR Factors for the 2025 Plan Year in Case No. U-21592 currently pending before the Michigan Public Service Commission. Pursuant to MCL 460.6j, the Company will adjust its rates to incorporate all or part of the requested factors as filed, including contingent factors, until the issuance of an order in U-21592.*

*The Company will file on or before September 30, 2024 for Maximum Allowable PSCR Factors for the 2025 Plan Year pursuant to MCL 460.6j.*

The Company will file a revised Sheet No. D-6.00 at least 10 days before the actual PSCR factor is billed to its customers in the subsequent billing month.

**Issued XXXXXX XX, 20XX by**
**Garrick J. Rochow,**
**President and Chief Executive Officer,**
**Jackson, Michigan**

**Effective for bills rendered for**
**the 2025 Plan Year**

**Issued under authority of the**
**Michigan Public Service Commission**
**for self-implementing**
**in Case No. U-21592**

## *MONTHLY POWER SUPPLY COST RECOVERY (PSCR) FACTOR CEILING PRICE ADJUSTMENT (CONTINGENCY) MECHANISM*

*The Maximum Allowable Power Supply Cost Recovery (PSCR) Factors on Sheet No. D-6.00 may be adjusted on a monthly basis, for the remaining months of the PSCR Plan Year, contingent upon NYMEX Henry Hub for natural gas for the Plan Year increasing to a level above the Plan prices which were incorporated in the calculation of the base PSCR ceiling factor. Any adjustment of the Maximum Allowable PSCR Factor shall be determined using the table set forth on Sheet No. D-6.20.*

*The Company shall file with the Commission an updated Sheet No. D-6.00 at least 10 days before any adjustment in the Maximum Allowable PSCR Factor if a contingency calculation under the method described below results in an increase or decrease to the Maximum Allowable PSCR ceiling factors on Sheet No. D-6.20. All supporting documents necessary to verify an adjustment in the Maximum Allowable PSCR Factor will be provided to the Michigan Public Service Commission Staff.*

*Definitions:*

| | |
|---|---|
| *NYMEX Futures Month Prices* | *NYMEX Henry Hub natural gas futures month settlement prices (in $/MMBtu).* |
| *NYMEX Increase* | $(X_{Forecast} - X_{Plan})$ |
| $X_{Forecast}$ | *Updated NYMEX Price forecast for the 12-month PSCR period reflecting an average of the actual monthly NYMEX Hub prices as published by S&P Global Platts for months in which they are available and the NYMEX Price for the remaining months in the PSCR period* |
| $X_{Plan}$ | *12-month average NYMEX Price incorporated in the Development of the base Maximum PSCR Factor* |

*Step 1* *Determine an updated 12-month Plan NYMEX Forecast for the PSCR period. The updated 12-month Plan NYMEX Forecast should be a 12-month average calculated using actual monthly NYMEX Hub prices published by S&P Global Platts for months in which they have become available and the NYMEX Price for the remaining months in the PSCR period.*

*Step 2* *Subtract the 12-month Plan NYMEX Forecast shown on Sheet No. D-6.20 from the updated 12-month NYMEX Price Forecast calculated in Step 1. The "Contingent PSCR Ceiling Factor" will be based on the price increases calculated.*

*Step 3* *Determine the "Contingent PSCR Ceiling Factor" using the following table on Sheet No. D-6.20. This "Contingent PSCR Ceiling Factor" will be the Maximum Allowable PSCR Factor for the remaining months of the PSCR Plan year, unless adjusted during a subsequent monthly review.*

**(Continued on Sheet No. D-6.20)**

## *MONTHLY POWER SUPPLY COST RECOVERY (PSCR) FACTOR*
## *CEILING PRICE ADJUSTMENT (CONTINGENCY) MECHANISM*

***(Continued From Sheet No. D-6.10)***

| | |
|---|---|
| *12-month Plan NYMEX Forecast* | *$3.210/MMBtu* |
| *Base PSCR Ceiling Factor* | *$0.00909/kWh* |

*Contingent PSCR Ceiling Factor*

| *NYMEX Forecast Increase* | *$/kWh* |
|---|---|
| *<$0.25* | *$0.00909* |
| *<0.50* | *0.01023* |
| *<0.75* | *0.01127* |
| *<1.00* | *0.01235* |
| *<1.25* | *0.01344* |
| *<1.50* | *0.01457* |
| *<1.75* | *0.01568* |
| *<2.00* | *0.01696* |
| *<2.25* | *0.01820* |
| *<2.50* | *0.01948* |
| *<2.75* | *0.02070* |
| *<3.00* | *0.02185* |
| *<3.25* | *0.02306* |
| *<3.50* | *0.02433* |
| *<3.75* | *0.02551* |
| *<4.00* | *0.02669* |
| *4.00* | *0.02796* |

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for approval to implement a power supply<br>cost recovery plan for the 12 months<br>ending December 31, 2025 | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21592 |

**PROOF OF SERVICE**

STATE OF MICHIGAN )
) SS
COUNTY OF JACKSON )

Crystal L. Chacon, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on September 30, 2024, she served an electronic copy of **Consumers Energy Company's Application with supporting Testimony and Exhibits of Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Zachery S. Cole, Joshua W. Hahn, Nathan J. Hoffman, Kevin C. Lott, Angela K. Rissman, Beth A. Skowronski, and Andrew G. Volansky** upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Crystal L. Chacon

Crystal L. Chacon

Subscribed and sworn to before me this 30th day of September 2024.

Melissa K. Harris

Melissa K. Harris, Notary Public
State of Michigan, County of Jackson
My Commission Expires: 06/11/2027
Acting in the County of Hillsdale

**ATTACHMENT 1 TO CASE NO. U-21592**
**(Including Parties to Case No. U-21423)**

| Party | Mailing Address | Email Address |
|---|---|---|
| **Counsel for Consumers Energy Company** | | |
| Evan B. Keimach, Esq.<br>Spencer A. Sattler, Esq.<br>Bret A. Totoraitis, Esq. | One Energy Plaza<br>Jackson, MI 49201 | evan.keimach@cmsenegy.com<br>spencer.sattler@cmsenergy.com<br>bret.totoraitis@cmsenergy.com<br>mpsc.filings@cmsenergy.com |
| **Counsel for the Michigan Public Service Commission Staff** | | |
| Anne B. Stirling, Esq.<br>Nicholas Q. Taylor, Esq. | 7109 West Saginaw Highway<br>Post Office Box 30221<br>Lansing, MI 48909 | stirlinga1@michigan.gov<br>taylorn10@michigan.gov |
| **Counsel for Attorney General Dana Nessel** | | |
| Celeste R. Gill, Esq. | ENRA Division<br>525 West Ottawa Street<br>6th Floor Williams Building<br>Post Office Box 30755<br>Lansing, MI 48909 | gillc1@michigan.gov<br>AG-ENRA-Spec-Lit@michigan.gov |
| **Counsel for Michigan Power Limited Partnership and Ada Cogeneration Limited Partnership ("MPLP/Ada")** | | |
| Jennifer Utter Heston, Esq. | Fraser Trebilcock Davis & Dunlap, P.C.<br>124 W. Allegan Street<br>Suite 1000<br>Lansing, MI 48933 | jheston@fraserlawfirm.com |
| **Counsel for Association of Businesses Advocating Tariff Equity ("ABATE")** | | |
| Michael J. Pattwell, Esq. | Clark Hill PLLC<br>212 E. Cesar E. Chavez Avenue<br>Lansing, MI 48906 | mpattwell@clarkhill.com |
| Stephen A. Campbell, Esq. | Clark Hill PLLC<br>500 Woodward Avenue, Suite 3500<br>Detroit, MI 48226 | scampbell@clarkhill.com |
| Axel N. Buchwalter, Esq. | Clark Hill PLLC<br>3200 N. Central Avenue, Suite 1600<br>Phoenix, AZ 85012 | abuchwalter@clarkhill.com |
| **Counsel for Energy Michigan, Inc.** | | |
| Timothy J. Lundgren, Esq.<br>Laura A. Chappelle, Esq.<br>Justin K. Ooms, Esq. | Potomac Law Group<br>120 N. Washington Square<br>Suite 300<br>Lansing, MI 48933 | tlundgren@potomaclaw.com<br>lchappelle@potomaclaw.com<br>jooms@potomaclaw.com<br>sdukes@potomaclaw.com |
| **Counsel for Sierra Club** | | |
| Christopher M. Bzdok, Esq. | Troposphere Legal<br>420 East Front Street<br>Traverse City, MI 49686 | chris@tropospherelegal.com<br>breanna@tropospherelegal.com |

* Receives Confidential Materials