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September 30, 2021

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

RE: Case No. U-21048 – 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, 2022.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case are the redacted versions of **Consumers Energy Company's Application with Supporting Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis.**

Please note that **Exhibit A-21 (SJN-1)** contains material which has been designated as confidential. The confidential version is being filed under seal with the Michigan Public Service Commission.

This is a paperless filing and is therefore being filed only in a PDF format. I have enclosed a Proof of Service showing electronic service upon the parties to MPSC Case Nos. U-20802 and U-20963.

Sincerely,

Michael C. Rampe
Digitally signed by Michael C. Rampe
Date: 2021.09.30 10:28:14 -04'00'

Michael C. Rampe

cc: Parties per Attachment 1 to the Proof of Service

STATE OF MICHIGAN

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, 2022	))))))	Case No. U-21048

APPLICATION

Consumers Energy Company ("Consumers Energy" or the "Company") hereby applies for approval of a Power Supply Cost Recovery ("PSCR") Plan and monthly PSCR Factors for the 12-month period January through December 2022. In support of this Application, Consumers Energy states as follows:

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") pursuant to certain provisions of 1939 PA 3, as amended by various acts, including 1982 PA 304, 2000 PA 141, 2008 PA 286, and 2016 PA 341, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; and 1909 PA 300, as amended, MCL 462.2 *et seq*.

3. This Application is filed pursuant to MCL 460.6j, and Consumers Energy's Rule C8. MCL 460.6j authorizes the Commission to approve a PSCR clause for electric utilities such as Consumers Energy. Company Rule C8 sets forth the Company's PSCR clause.

4. 1982 PA 304 provides that a utility is to be reimbursed for booked costs, including transportation costs, reclamation costs, and disposal and reprocessing costs of fuel

burned by the utility for electric generation and the booked costs of purchased and net interchanged power transactions by the utility incurred under reasonable and prudent policies and practices. 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. Underrecoveries will send customers inaccurate price signals, impose interest costs on customers at a date after the power supply costs are incurred, and interfere with utility cash flow.

5. Rule C8 of Consumers Energy's electric tariffs 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. Accompanying this Application are the testimony and exhibits of witnesses for Consumers Energy that meet the requirements of Rule C8 with respect to calendar year 2022. The prefiled testimony and exhibits include an evaluation and conclusions as to the reasonableness and prudence of the forecasted costs of fuel and purchased and net interchange power. Also included in these materials is a five-year forecast of the power supply requirements of Consumers Energy's customers, anticipated sources of supply, and projections of power supply costs.

6. As more fully described in the accompanying testimony and exhibits, Consumers Energy seeks approval to apply, for each month in calendar year 2022, a uniform maximum PSCR Factor of $0.00177 per kWh for all classes of customers.

7. The accompanying testimony and exhibits, as provided by Company witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis, are an integral part of this Application, and the relief described therein is incorporated by reference in this Application, as if fully set forth herein. This testimony includes, among other things, 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.

8. 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 set forth 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 commencing hearings on the relief sought herein;

B. Approve for 2022 a maximum monthly PSCR Factor of not less than \$0.00177 per kWh for all classes of customers as set forth herein, and more fully explained in the accompanying testimony;

C. Approve the PSCR Plan for 2022 described in this Application; and

D. Grant Consumers Energy such further and additional relief as may be lawful and appropriate.

Respectfully submitted,

CONSUMERS ENERGY COMPANY

Date: September 30, 2021

By: Tim Sparks

Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

Michael C. Rampe

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STATE OF MICHIGAN

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, 2022	))))))	Case No. U-21048

VERIFICATION

Timothy J. Sparks, being first duly sworn, deposes and says that he is the Vice President of Electric Grid Integration of Consumers Energy Company; that he has executed the foregoing 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, 2021

By: ______________________________
Timothy J. Sparks
Vice President of Electric Grid Integration
Consumers Energy Company

PREFILED EXHIBITS

Exhibit of Daniel S. Alfred

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

Exhibits of Eugène M.J.A. Breuring

Exhibit A-2 (EMB-1)	2022 Forecast of Calendar Total Electric Deliveries;
Exhibit A-3 (EMB-2)	Forecast of Annual Calendar Deliveries;
Exhibit A-4 (EMB-3)	Forecast of Total Monthly Generation Requirements;
Exhibit A-5 (EMB-4)	Forecast of Total Monthly Peak Demand; and
Exhibit A-6 (EMB-5)	Forecasted System Load Factor Based on Summer Peak Demand.

Exhibits of Joshua W. Hahn

Exhibit A-7 (JWH-1)	Monthly Summary of the projected 2022 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2022 through 2026 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2022 Rates; and
Exhibit A-10 (JWH-4)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRCs).

Exhibits of Norman J. Kapala

Exhibit A-11 (NJK-1)	Major Outages in the 2022 PSCR Plan;
Exhibit A-12 (NJK-2)	2022 PSCR Random Outage Rate Projections;
Exhibit A-13 (NJK-3)	2022-2026 Urea Expense;
Exhibit A-14 (NJK-4)	2022-2026 Aqueous Ammonia Expense;

Exhibit A-15 (NJK-5)	2022-2026 Lime Expense; and
Exhibit A-16 (NJK-6)	2022-2026 Activated Carbon Expense.

<u>Exhibits of Kevin C. Lott</u>

Exhibit A-17 (KCL-1)	Projected As-Burned Coal Costs – 2022;
Exhibit A-18 (KCL-2)	Projected As-Burned Coal Costs (2023-2026);
Exhibit A-19 (KCL-3)	Projected As-Burned Oil & Gas Costs – 2022; and
Exhibit A-20 (KCL-4)	Projected As-Burned Oil & Gas Costs (2023-2026).

<u>Exhibit of Stephen J. Nadeau</u>

Exhibit A-21 (SJN-1) (Confidential)	Jackson Lateral Transportation Agreement.

<u>Exhibit of Angela K. Rissman</u>

Exhibit A-22 (AKR-1)	2022-2026 Coal Contract & Purchase Data.

<u>Exhibits of Andrew G. Volansky</u>

Exhibit A-23 (AGV-1)	Calculation of 2022 PSCR Factor.

<u>Exhibit of Emily M Walainis</u>

Exhibit A-24 (EMW-1)	New and Amended Power Purchase Agreements not Previously Included in the Company's PSCR Plan.

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, 2022	))))))	Case No. U-21048

DIRECT TESTIMONY

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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 Principal Rate Analyst in the Energy Markets and Transmission Regulation 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 of 2003.

Q. Please describe your business experience.

A. In January of 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 of 1999. During August of 2001, I transferred to a position in the Revenue Requirements section of the Rates Department. In February of 2004, I was promoted to a Senior Rate Analyst in the Revenue section of the Rates and Business Support Department. In March of 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 of 2020, I was promoted to my current position of Principal Rate Analyst.

Q. What are your responsibilities as Principal Rate Analyst?

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;

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; and

Case No. U-20802 2021 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 2022 for which the Company seeks recovery in this proceeding; (ii) identify generation-related credits to PSCR costs relating to Schedule 2 Reactive revenues; and (iii) 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:

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 2022 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 2019 PSCR Plan, Case No. U-20219.

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 2022 in the Company's total transmission costs.

A. The transmission and energy-market-related charges included in the total transmission costs projected for 2022 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, and 26-A. 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 Emily M. Walainis 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 Eugene M. 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 2021 PSCR Plan year and the five-year period 2022 through 2026 is shown on Exhibit A-1 (DSA-1), line 16.

Q. Please describe the MISO Schedule 2 rate and forecasted cost of this expense.

A. MISO Schedule 2 is the Tariff schedule for an ancillary service required to be provided by MISO for Reactive Supply and Voltage Control from Generation Sources. The rate for this service is a pricing zone wide rate. Applying the applicable pricing zone rate to the Company's forecasted monthly coincident peak produces the Company's forecasted expense. This forecasted expense for the 2022 PSCR Plan year and the five-year period 2022 through 2026 is shown on Exhibit A-1 (DSA-1), line 17.

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 and is updated biannually. The Company's forecasted expense for the 2022 PSCR Plan year and the five-year period 2022 through 2026 is shown on Exhibit A-1 (DSA-1), line 18.

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 2022 PSCR Plan year and the five-year period 2022 through 2026 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 19. The second rate is applied to actual volume of MWh of transmission service received. The Company's forecasted expense for the 2022 PSCR Plan year and the five-year period 2022 through 2026 for this portion of Schedule 10 is shown on Exhibit A-1 (DSA-1), line 20.

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 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 21.

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 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 22.

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 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 23.

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 Market. This rate is charged on the same basis as Schedule 17. The Company's forecasted expenses for the 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 24.

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 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 25.

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 shall be in addition to any charges under Schedules 7, 8, 9, and 26. Grandfathered Agreements will not be charged this Schedule. The Company's forecasted expenses for the 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 26.

Q. Will the Company be providing Blackstart Service in the 2022 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 2022 PSCR Plan year and the five-year period 2022 through 2026 are shown on Exhibit A-1 (DSA-1), line 27.

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 2022 equals $458,831,148 and can be found on Exhibit A-1 (DSA-1), page 1, line 31, column (o). It is composed of

$452,154,488 of transmission expenses (line 29, column (o)) and $6,676,661 of energy market administration expenses (line 30, column (o)).

SCHEDULE 2 REACTIVE REVENUE REQUIREMENT CREDIT

Q. What is the basis for proposing to credit reactive revenue requirements revenues against total PSCR costs?

A. Consumers Energy provides generation-related reactive services that are necessary for the transmission of power. The Company receives revenue from MISO for providing this service. Consumers Energy incurs an expense under the MISO Tariff when it receives reactive service within the MJZ pricing zone. The revenues received from this service should be credited against total power costs for Consumers Energy's retail customers via the PSCR factor, since the expense for the service is included in the PSCR.

Q. Have you identified the revenues the Company expects to receive in 2022 from Schedule 2?

A. Yes. The Company expects to receive $4,500,000 in 2022. This amount is composed of the FERC-approved revenue requirements established in FERC Docket No. ER-16-1058.

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 dealing with transmission planning and project approval. It is primarily through this stakeholder process that the Company works 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 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

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, 2022	))))))	Case No. U-21048

EXHIBIT

OF

DANIEL S. ALFRED

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

Consumers Energy Company

2022 Transmission and Energy Market Administration Expenses

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	5,047	4,786	4,720	4,460	5,174	6,598	6,449	5,933	6,233	4,712	4,831	5,105	**64,050**
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	3011767.588	2747804.278	2802211.793	2563770.363	2674734.617	2968024.593	3188828.278	3116584.3	2747106.88	2691937.669	2703556.735	2946635.755	**34,162,963**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	196.6288995	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	196.6289	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	4710.372169	4710.372169	4710.372169	4710.372169	4710.372169	4749.207795	4749.207795	4749.207795	4749.207795	4749.207795	4749.207795	4749.207795	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	0.0821	
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	1039.597576	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	1,039.5976	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.650152125	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	1.6502	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.299268127	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	4.2993	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 339,139	$ 321,582	$ 317,158	$ 299,652	$ 347,668	$ 443,319	$ 433,337	$ 398,632	$ 418,828	$ 316,624	$ 324,633	$ 343,017	**$ 4,303,589**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	992,457	941,079	928,130	876,901	1,017,416	1,297,329	1,268,118	1,166,556	1,225,658	926,568	950,006	1,003,804	**12,594,023**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	23,774,952	22,544,150	22,233,963	21,006,736	24,372,866	31,334,590	30,629,044	28,176,012	29,603,501	22,379,535	22,945,640	24,245,040	**303,246,027**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	245,593	217,854	229,674	209,997	251,769	310,680	313,807	288,675	293,516	229,288	227,504	248,400	**3,066,757**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	281,299	256,645	261,727	239,456	249,820	277,213	297,837	291,089	256,580	251,427	252,512	275,216	**3,190,821**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	219,859	200,590	204,561	187,155	195,256	216,666	232,784	227,511	200,539	196,511	197,360	215,104	**2,493,896**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,531	19,987	21,071	19,266	23,098	28,503	28,790	26,484	26,928	21,036	20,872	22,789	**281,354**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	494,532	451,189	460,123	420,971	439,191	487,350	523,606	511,743	451,075	442,016	443,924	483,838	**5,609,559**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	69,271	63,199	64,451	58,967	61,519	68,265	73,343	71,681	63,183	61,915	62,182	67,773	**785,748**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,247,225	4,975,582	4,907,123	4,636,269	5,379,187	6,859,115	6,704,672	6,167,705	6,480,181	4,898,861	5,022,781	5,307,219	**66,585,920**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,969,875	4,534,295	4,624,076	4,230,611	4,413,719	4,897,692	5,262,052	5,142,838	4,533,144	4,442,107	4,461,280	4,862,397	**56,374,086**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,700	20,577	20,293	19,173	22,246	28,366	27,727	25,507	26,799	20,259	20,772	21,948	**275,367**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$36,094,098**	**$34,014,353**	**$33,728,705**	**$31,707,951**	**$36,251,946**	**$45,666,971**	**$45,171,379**	**$41,886,525**	**$43,040,746**	**$33,663,180**	**$34,404,488**	**$36,524,145**	**$** 452,154,488
30	Total Energy Market Administration Expenses	**Lines 22-24**	**586,334**	**534,376**	**545,645**	**499,204**	**523,808**	**584,117**	**625,738**	**609,909**	**541,187**	**524,966**	**526,978**	**574,399**	6,676,661
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$36,680,432**	**$34,548,729**	**$34,274,351**	**$32,207,154**	**$36,775,755**	**$46,251,088**	**$45,797,117**	**$42,496,433**	**$43,581,933**	**$34,188,146**	**$34,931,465**	**$37,098,545**	**$** 458,831,148

Consumers Energy Company

2023 Transmission and Energy Market Administration Expenses

Case No.: U-21048
Exhibit No.: A-1 (DSA-1)
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Witness: DSAlfred
Date: September 2021

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	5,132	4,815	4,898	4,393	5,208	6,610	6,431	5,910	6,279	4,898	4,989	5,262	**64,824**
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	2985764.928	2702288.849	2807509.46	2559009.114	2682808.57	2932578.497	3227224.536	3138239.33	2772637.374	2717440.886	2719086.77	2968036.681	**34,212,625**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	194.0725448	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	194.0725	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5022.223181	5022.223181	5022.223181	5022.223181	5022.223181	4979.08344	4979.08344	4979.08344	4979.08344	4979.08344	4979.08344	4979.08344	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	0.0850	
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	1101.034173	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	1,101.0342	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.635040782	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	1.6350	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.243373728	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	4.2434	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 344,828	$ 323,498	$ 329,085	$ 295,138	$ 349,948	$ 444,135	$ 432,082	$ 397,083	$ 421,907	$ 329,133	$ 335,223	$ 353,560	**$ 4,355,619**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	995,985	934,378	950,514	852,464	1,010,774	1,282,818	1,248,005	1,146,916	1,218,615	950,654	968,242	1,021,205	**12,580,570**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	25,774,174	24,179,889	24,597,458	22,060,126	26,156,885	32,911,712	32,018,557	29,425,018	31,264,534	24,389,773	24,841,009	26,199,823	**323,818,959**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	249,712	211,595	238,311	206,834	253,420	311,251	312,898	287,553	295,674	238,347	234,925	256,035	**3,096,556**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	278,870	252,394	262,221	239,011	250,574	273,903	301,423	293,112	258,964	253,809	253,963	277,215	**3,195,459**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	217,961	197,267	204,948	186,808	195,845	214,078	235,587	229,091	202,403	198,373	198,493	216,667	**2,497,522**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,909	19,412	21,863	18,976	23,250	28,555	28,706	26,381	27,126	21,867	21,553	23,489	**284,088**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	507,580	459,389	477,277	435,032	456,077	498,538	548,628	533,501	471,348	461,965	462,245	504,566	**5,816,146**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,673	62,153	64,573	58,857	61,705	67,449	74,226	72,180	63,771	62,501	62,539	68,265	**786,890**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,650,535	5,301,016	5,392,560	4,836,295	5,734,437	7,277,829	7,080,324	6,506,810	6,913,586	5,393,357	5,493,139	5,793,617	**71,373,506**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,881,847	4,418,352	4,590,392	4,184,084	4,386,501	4,794,885	5,276,644	5,131,149	4,533,375	4,443,127	4,445,818	4,852,861	**55,939,037**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,777	20,430	20,783	18,639	22,100	28,049	27,287	25,077	26,645	20,786	21,170	22,329	**275,073**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 38,417,690**	**$ 35,840,819**	**$ 36,588,274**	**$ 32,881,400**	**$ 38,362,486**	**$ 47,540,661**	**$ 46,934,808**	**$ 43,443,809**	**$ 45,137,702**	**$ 36,219,359**	**$ 36,793,983**	**$38,995,311**	**$** 477,156,301
30	Total Energy Market Administration Expenses	**Lines 22-24**	**599,162**	**540,954**	**563,713**	**512,864**	**541,032**	**594,543**	**651,561**	**632,061**	**562,245**	**546,333**	**546,337**	**596,321**	6,887,124
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 39,016,852**	**$ 36,381,773**	**$ 37,151,986**	**$ 33,394,265**	**$ 38,903,518**	**$ 48,135,204**	**$ 47,586,369**	**$ 44,075,870**	**$ 45,699,947**	**$ 36,765,692**	**$ 37,340,319**	**$39,591,631**	**$** 484,043,426

Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-1 (DSA-1)
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Witness: DSAlfred
Date: September 2021

2024 Transmission and Energy Market Administration Expenses

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	5,163	4,970	4,872	4,449	5,224	6,624	6,414	5,888	6,283	4,894	4,929	5,260	**64,971**
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	2968866.751	2743385.975	2795017.695	2551022.294	2672326.659	2921315.565	3212246.109	3129210.076	2763435.234	2708912.882	2710366.819	2960909.359	**34,137,015**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	194.0409777	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	194.0410	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5338.422523	5338.422523	5338.422523	5338.422523	5338.422523	5345.48706	5345.48706	5345.48706	5345.48706	5345.48706	5345.48706	5345.48706	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	
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	1084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	1,084.5768	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	1.7656	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	4.2427	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 346,883	$ 333,962	$ 327,341	$ 298,934	$ 351,008	$ 445,061	$ 430,980	$ 395,649	$ 422,152	$ 328,843	$ 331,212	$ 353,446	**$ 4,365,471**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	1,001,759	964,443	945,323	863,286	1,013,672	1,285,284	1,244,620	1,142,587	1,219,125	949,662	956,501	1,020,712	**12,606,974**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	27,560,233	26,533,606	26,007,564	23,750,572	27,887,965	35,407,316	34,287,078	31,476,265	33,584,739	26,161,512	26,349,921	28,118,829	**347,125,599**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	251,201	218,439	237,049	209,494	254,188	311,900	312,100	286,514	295,845	238,137	232,115	255,953	**3,102,935**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	277,292	256,232	261,055	238,265	249,595	272,851	300,024	292,268	258,105	253,012	253,148	276,549	**3,188,397**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	216,727	200,267	204,036	186,225	195,080	213,256	234,494	228,432	201,731	197,751	197,857	216,146	**2,492,002**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	23,046	20,040	21,748	19,220	23,320	28,615	28,633	26,286	27,142	21,847	21,295	23,482	**284,673**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	510,645	471,862	480,743	438,776	459,640	502,466	552,506	538,224	475,311	465,933	466,183	509,276	**5,871,567**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	68,284	63,098	64,285	58,674	61,464	67,190	73,882	71,972	63,559	62,305	62,338	68,101	**785,151**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,599,255	5,390,681	5,283,808	4,825,268	5,665,838	7,183,995	6,956,704	6,386,402	6,814,202	5,308,061	5,346,288	5,705,192	**70,465,694**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,241,884	4,843,771	4,934,933	4,504,131	4,718,308	5,157,927	5,671,599	5,524,989	4,879,171	4,782,905	4,785,472	5,227,835	**60,272,927**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,903	21,087	20,669	18,876	22,164	28,103	27,213	24,983	26,656	20,764	20,914	22,318	**275,650**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 40,519,138**	**$ 38,764,490**	**$ 38,223,779**	**$ 34,897,050**	**$ 40,359,818**	**$ 50,307,693**	**$ 49,466,812**	**$ 45,760,089**	**$ 47,703,725**	**$ 38,242,647**	**$ 38,475,428**	**$ 41,198,981**	**$ 503,919,649**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**601,975**	**555,001**	**566,776**	**516,669**	**544,424**	**598,271**	**655,021**	**636,482**	**566,012**	**550,085**	**549,816**	**600,859**	**6,941,391**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 41,121,113**	**$ 39,319,490**	**$ 38,790,555**	**$ 35,413,718**	**$ 40,904,241**	**$ 50,905,964**	**$ 50,121,833**	**$ 46,396,571**	**$ 48,269,736**	**$ 38,792,732**	**$ 39,025,244**	**$ 41,799,840**	**$ 510,861,040**

5,414

Consumers Energy Company

2025 Transmission and Energy Market Administration Expenses

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	5,022	4,735	4,790	4,332	5,110	6,561	6,251	5,716	6,199	4,805	4,877	5,126	**63,525**
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	2902947.56	2629678.699	2732454.754	2493618.502	2612289.955	2856011.417	3140911.401	3055641.964	2701432.397	2647705.447	2649288.233	2872464.353	**33,294,445**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	198.0967624	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	198.0968	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	5711.134581	5711.134581	5711.134581	5711.134581	5711.134581	5723.553013	5723.553013	5723.553013	5723.553013	5723.553013	5723.553013	5723.553013	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	
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	1089.179443	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	1,089.1794	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.749470283	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	1.7495	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.33136278	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	4.3314	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 337,462	$ 318,170	$ 321,840	$ 291,065	$ 343,356	$ 440,828	$ 419,999	$ 384,084	$ 416,486	$ 322,861	$ 327,725	$ 344,452	**$ 4,268,328**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	994,920	938,044	948,862	858,130	1,012,299	1,299,670	1,238,260	1,132,374	1,227,904	951,873	966,215	1,015,531	**12,584,080**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	28,683,573	27,043,818	27,355,726	24,739,902	29,184,604	37,550,992	35,776,699	32,717,348	35,477,469	27,502,185	27,916,569	29,341,435	**363,290,319**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	244,378	215,542	233,065	203,979	248,646	308,934	304,148	278,140	291,875	233,804	229,671	249,440	**3,041,623**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	271,135	245,612	255,211	232,904	243,988	266,751	293,361	285,397	252,314	247,296	247,444	268,288	**3,109,701**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	211,915	191,967	199,469	182,034	190,697	208,489	229,287	223,062	197,205	193,282	193,398	209,690	**2,430,494**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	22,420	19,775	21,382	18,714	22,812	28,343	27,904	25,517	26,778	21,450	21,071	22,884	**279,048**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	499,307	452,305	469,982	428,902	449,314	491,234	540,237	525,570	464,646	455,405	455,678	494,064	**5,726,644**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	66,768	60,483	62,846	57,353	60,083	65,688	72,241	70,280	62,133	60,897	60,934	66,067	**765,772**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,470,289	5,157,569	5,217,053	4,718,186	5,565,842	7,145,870	6,808,226	6,226,039	6,751,284	5,233,605	5,312,461	5,583,610	**69,190,034**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	5,078,620	4,600,545	4,780,348	4,362,511	4,570,124	4,996,507	5,494,931	5,345,755	4,726,076	4,632,082	4,634,851	5,025,291	**58,247,642**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,754	20,510	20,747	18,763	22,134	28,417	27,074	24,759	26,848	20,813	21,126	22,204	**275,149**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 41,316,046**	**$ 38,733,777**	**$ 39,334,322**	**$ 35,609,474**	**$ 41,383,690**	**$ 52,248,459**	**$ 50,593,986**	**$ 46,618,956**	**$ 49,369,460**	**$ 39,339,800**	**$ 39,851,460**	**$ 42,061,942**	**$ 516,461,372**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**588,495**	**532,562**	**554,211**	**504,969**	**532,208**	**585,265**	**640,381**	**621,368**	**553,557**	**537,752**	**537,682**	**583,015**	**6,771,465**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 41,904,541**	**$ 39,266,339**	**$ 39,888,532**	**$ 36,114,443**	**$ 41,915,898**	**$ 52,833,724**	**$ 51,234,367**	**$ 47,240,324**	**$ 49,923,017**	**$ 39,877,553**	**$ 40,389,142**	**$ 42,644,957**	**$ 523,232,836**

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Consumers Energy Company

2026 Transmission and Energy Market Administration Expenses

Case No.: U-21048
Exhibit No.: A-1 (DSA-1)
Page: 5 of 5
Witness: DSAlfred
Date: September 2021

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	4,867	4,566	4,651	4,650	5,083	6,516	6,124	5,591	6,158	4,640	4,720	4,996	**62,562**
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	2856629.865	2581801.182	2703333.945	2447430.045	2577642.529	2818009.35	3112535.228	3019881.843	2644896.204	2607588.542	2609697.218	2848174.045	**32,827,620**
	Rates														
4	Schedule 1 - System Control and Dispatch	Workpaper DSA-6	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	$ 67.1914	
5	Schedule 2 - Reactive Support	Workpaper DSA-4	201.0560223	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	201.0560	
6	Schedule 9 - Network Transmission Service	Workpaper DSA-5	6015.594854	6015.594854	6015.594854	6015.594854	6015.594854	5990.368545	5990.368545	5990.368545	5990.368545	5990.368545	5990.368545	5990.368545	
7	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Workpaper DSA-6	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	0.0654	
8	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Workpaper DSA-6	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	0.0934	
9	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Workpaper DSA-6	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	0.0730	
10	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Workpaper DSA-6	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	0.0060	
11	Schedule 17 - ISO Cost Adder - Energy Markets	Workpaper DSA-6	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860	
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	1087.113338	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	1,087.1133	
14	Schedule 26-A - Multi-Value Project Usage Rate	Workpaper DSA-5a	1.733423275	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	1.7334	
15	Schedule 33 - Blackstart Service	Workpaper DSA-5a	4.396066654	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	4.3961	
	Expenses														
16	Schedule 1 - System Control and Dispatch	Line 1 * Line 4	$ 327,032	$ 306,789	$ 312,483	$ 312,468	$ 341,559	$ 437,788	$ 411,462	$ 375,671	$ 413,736	$ 311,790	$ 317,144	$ 335,692	**$ 4,203,613**
17	Schedule 2 - Reactive Support	Line 1 * Line 5	978,573	918,000	935,040	934,993	1,022,043	1,309,989	1,231,213	1,124,116	1,238,016	932,966	948,985	1,004,487	**12,578,420**
18	Schedule 9 - Network Transmission Service	Line 1 * Line 6	29,278,885	27,466,542	27,976,376	27,974,998	30,579,525	39,030,496	36,683,414	33,492,503	36,886,100	27,797,265	28,274,553	29,928,216	**375,368,872**
19	Schedule 10 - ISO Cost Recovery Adder - Demand Basis	Line 1 * Line 2 * Line 7	236,825	200,665	226,289	218,979	247,345	306,804	297,966	272,048	289,948	225,787	222,255	243,096	**2,988,006**
20	Schedule 10 - ISO Cost Recovery Adder - Energy Basis	Line 3 * Line 8	266,809	241,140	252,491	228,590	240,752	263,202	290,711	282,057	247,033	243,549	243,746	266,019	**3,066,100**
21	Schedule 10-FERC - ISO Cost Recovery Adder - FERC Annual Charge	Line 3 * Line 9	208,534	188,471	197,343	178,662	188,168	205,715	227,215	220,451	193,077	190,354	190,508	207,917	**2,396,416**
22	Schedule 16 - ISO Cost Adder - Financial Transmission Rights	Line 1 * Line 2 * Line 10	21,727	18,410	20,760	20,090	22,692	28,147	27,336	24,958	26,601	20,714	20,390	22,302	**274,129**
23	Schedule 17 - ISO Cost Adder - Energy Markets	(Line 3 * 2) * Line 11	491,340	444,070	464,973	420,958	443,355	484,698	535,356	519,420	454,922	448,505	448,868	489,886	**5,646,351**
24	Schedule 24 - Balancing Area Cost Adder - Energy Markets	(Line 3 * 2) * Line 12	65,702	59,381	62,177	56,291	59,286	64,814	71,588	69,457	60,833	59,975	60,023	65,508	**755,035**
25	Schedule 26 - Network Upgrade Charge from Transmission Expansion Plan	Line 1 * Line 13	5,291,159	4,963,639	5,055,775	5,055,526	5,526,205	7,083,132	6,657,191	6,078,115	6,693,974	5,044,561	5,131,177	5,431,279	**68,011,732**
26	Schedule 26-A - Multi-Value Project Usage Rate	Line 3 * Line 14	4,951,749	4,475,354	4,686,022	4,242,432	4,468,146	4,884,803	5,395,341	5,234,733	4,584,725	4,520,055	4,523,710	4,937,091	**56,904,161**
27	Schedule 33 - Blackstart Service	Line 1 * Line 15	21,396	20,072	20,445	20,444	22,347	28,643	26,920	24,579	27,069	20,399	20,749	21,963	**275,026**
28	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**
29	Total Transmission Expenses	**Lines 16-21 + 25-28**	**$ 41,562,960**	**$ 38,782,672**	**$ 39,664,264**	**$ 39,169,091**	**$ 42,638,089**	**$ 53,552,572**	**$ 51,223,434**	**$ 47,106,272**	**$ 50,575,677**	**$ 39,288,724**	**$ 39,874,828**	**$ 42,377,761**	**$ 525,816,345**
30	Total Energy Market Administration Expenses	**Lines 22-24**	**578,770**	**521,861**	**547,911**	**497,339**	**525,332**	**577,659**	**634,281**	**613,835**	**542,355**	**529,194**	**529,281**	**577,696**	**6,675,515**
31	**Total Transmission and Energy Markets Administration Expenses**	**Lines 30 + 31**	**$ 42,141,730**	**$ 39,304,533**	**$ 40,212,174**	**$ 39,666,430**	**$ 43,163,422**	**$ 54,130,231**	**$ 51,857,715**	**$ 47,720,108**	**$ 51,118,033**	**$ 39,817,919**	**$ 40,404,109**	**$ 42,955,457**	**$ 532,491,860**

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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	)	Case No. U-21048
12 months ending December 31, 2022	)	
______________________________________	)	

DIRECT TESTIMONY

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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 Senior Rate Analyst III in the Planning, Budgeting and 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 of 2013, I accepted the position of Senior Rate Analyst II. In 2020, I was promoted to Senior Analyst III, which is my current position at Consumers Energy. In this capacity, I am responsible for preparing the Company's electric sales and customer forecasts, sponsoring the sales and customer forecast testimony and exhibits, conducting industry research, and conducting various economic studies. I am also 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	2016 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	2017 General Electric Rate Case;
U-18402	2018 PSCR Plan;
U-20134	2018 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	2020 General Electric Rate Case;
U-20802	2021 PSCR Plan;
U-20875	2021-2025 EWR Plan;
U-20963	2021 General Electric Rate Case; and
U-21090	2021 IRP.

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 2022 to 2026, in support of the Company's 2022 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)	2022 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. 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 Heating Degree Days ("HDD") and Cooling Degree Days ("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 will be discussed below.

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 IHS Markit, a leading publishing company that provides industry-specific data and analysis.

Q. Please describe the impact of demographics on the forecasting process.

A. Population projections are used in the development of the long-term customer forecast. In particular, the forecast of residential customers is derived from the county-level population projections provided by IHS Markit.

SECTION II. 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 temporal cycles, 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 HDD and CDD variables prior to entering the modeling framework. The second step is importing the economic and demographic variables from IHS Markit into the sales modeling framework. The third step is importing electric use forecasts for wholesale, electric vehicles, polycrystalline production, 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 similar to 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. A weighted sum 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"); and (4) 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 of these statistical tests are used to evaluate how well the models fit the historical data, and also 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 of 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%.

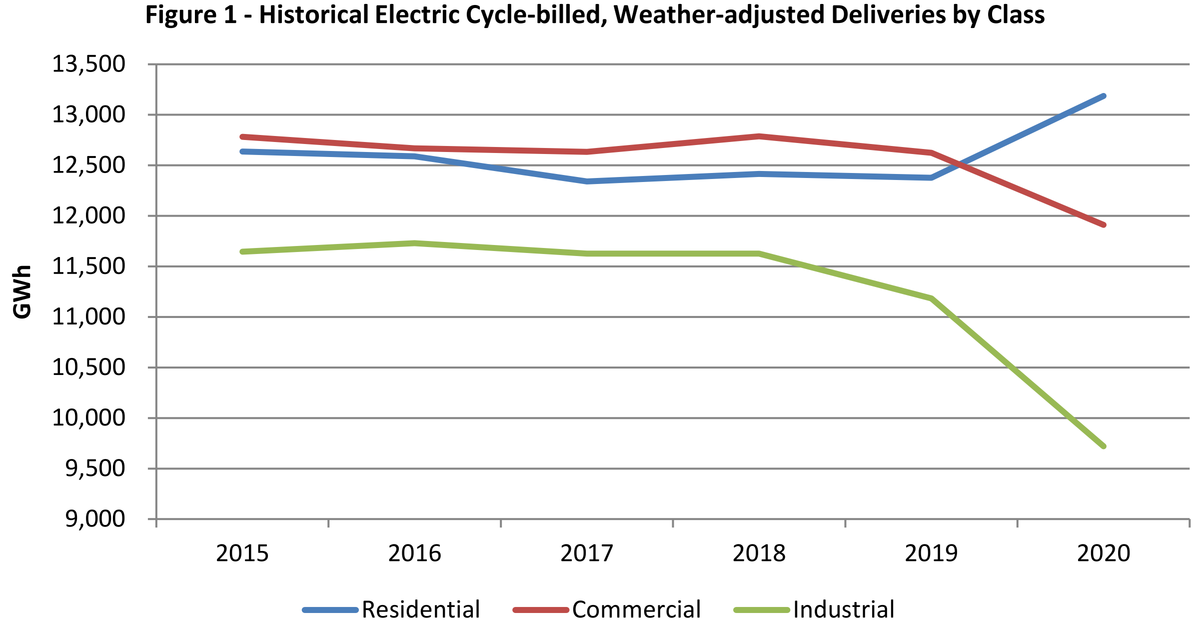
Q. Please explain the criteria used when considering the t-statistics and p-values associated with the model coefficients.

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 ("β") 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 β 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.

SECTION III. HISTORICAL AND FORECASTED ELECTRIC DELIVERIES

Q. Please explain the Company's historical levels of electric deliveries for the five-year period from 2015 to 2020.

A. In the past five years, weather-normalized electric deliveries decreased at a 1.2% Compound Annual Growth Rate ("CAGR") from 2015 to 2020, with most of the observed retraction occurring in the industrial class (-3.6%), followed by the commercial class (-1.4%). The residential class showed an increase of 0.9% during this five-year period. These changes are graphically depicted in Figure 1.



Q. What is the cause of the gradual decrease in weather-normalized residential and commercial deliveries from 2015 to 2017 in the Company's service territory?

A. In large part, the retraction in the residential and commercial sectors is caused by a nearly flat population growth in the electric service territory during this period, coupled with increased energy efficiency efforts, starting in 2008.

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, as well as state-mandated restrictions, that caused an increase in "work from home," and halting or reducing operations of 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 commercial and industrial deliveries decreased by 5.7% and 7.3% respectively.

These changing paradigms were escalated due to Michigan Governor Whitmer's executive orders ("EO") and other public health organization orders, mandating the closings of bars, restaurants, theatres, gyms, and hair/nail salons, as well as K-12 schools (i.e., EO 2020-9 and EO 2020-20). Further, in March 2020, the governor issued a "Stay at Home" order (EO 2020-21; EO 2020-42; EO 2020-59), mandating Michigan non-essential residents to stay at home and limit large social gatherings, further pushing electric deliveries away from C&I and more toward the residential class. The "Stay at Home" order was into 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.

Q. What are the electric delivery expectations from 2022 to 2026?

A. Total electric deliveries are expected to increase 0.5% per year from 2022 to 2026. The 2022 monthly class level results of the electric deliveries forecast process are shown in Exhibit A-2 (EMB-1). The annual class level results for 2022 to 2026 are shown in Exhibit A-3 (EMB-2).

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 1.8% through 2020. From 2022 to 2026, the Company expects to grow EWR savings to 2.0%, as filed in the IRP, Case No. U-20165.

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

A. Per the 2018 System Loss Study, the forecasted total electric deliveries are increased by a line loss factor of 7.73% to determine 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. Weather-normal peak demand grew at a 1.6% CAGR from 2003 to 2007, but reversed much of this trend during the 2007 to 2009 recession. Looking forward, peak demand is expected to decrease by 0.3% per year from 2022 to 2026. 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 17 MW in the period 2022 to 2026 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 740 MW in 2022. The cumulative reductions produced by the EWR program are expected to be approximately 1,013 MW by 2026.

Q. What process is used to identify the peak demand impacts of the Company's EWR program?

A. The Company developed hourly load profiles for the EWR programs. The monthly energy savings associated with each of these programs are integrated with the corresponding load shape to develop hourly demand savings curves.

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 33 MW in 2022. The cumulative reductions produced by the Company's CVR program are expected to be 79 MW by 2026.

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

A. The newly introduced RSP is expected to reduce the Company's peak demand by approximately 119 MW in each of the years between 2022 and 2026.

Q. How did the Company derive this RSP peak demand reduction?

A. During the summer of 2019, the Company had an RSP pilot program in place with approximately 48,000 residential customers. This pilot group exhibited behavior that shifted an average of 3.5% load from the on-peak hours (2PM to 7PM) to the off-peak hours (7PM to 2PM) in the month of July.

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 Commercial and Industrial 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 2022 to 2026 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 cost recovery plan for the	)	Case No. U-21048
12 months ending December 31, 2022	)	
______________________________	)	

EXHIBITS

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2022 Forecast of Calendar Total Electric Deliveries
(MWh)

Case No.: U-21048
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) Residential	(b) Commercial	(c) Industrial	(d) Street Lighting	(e) Inter-departmental	(f) Wholesale	(g) Total
1	January	1,206,350	1,029,635	816,219	14,454	5,560	29,770	3,101,988
2	February	1,047,095	901,056	838,074	11,887	1,818	24,694	2,824,624
3	March	1,025,910	1,011,632	818,832	10,834	3,313	28,269	2,898,790
4	April	874,571	946,743	803,036	9,668	2,142	31,601	2,667,760
5	May	899,237	1,042,853	802,673	8,163	2,362	30,678	2,785,966
6	June	1,050,865	1,070,799	917,979	7,280	2,361	30,495	3,079,779
7	July	1,354,650	1,146,681	750,917	8,552	2,493	32,647	3,295,941
8	August	1,251,349	1,080,597	868,374	9,298	2,825	32,973	3,245,417
9	September	903,530	1,054,512	864,611	10,840	2,997	31,595	2,868,085
10	October	885,186	993,255	897,505	12,670	3,110	28,283	2,820,009
11	November	943,145	936,507	871,890	14,095	2,309	29,348	2,797,294
12	December	1,143,604	1,018,194	824,011	15,174	952	30,522	3,032,457
13	Annual	12,585,492	12,232,465	10,074,122	132,915	32,243	360,875	35,418,111

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2022 Forecast of Calendar Full Service Electric Deliveries
(MWh)

Case No.: U-21048
Exhibit No.: A-2 (EMB-1)

Witness: EMBreuring
Date: September 2021

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	1,206,350	949,243	597,069	14,454	5,560	29,770	2,802,446
2	February	1,047,095	828,633	643,194	11,887	1,818	24,694	2,557,321
3	March	1,025,910	933,909	605,071	10,834	3,313	28,269	2,607,307
4	April	874,571	878,635	588,905	9,668	2,142	31,601	2,385,522
5	May	899,237	961,913	584,844	8,163	2,362	30,678	2,487,198
6	June	1,050,865	985,482	683,156	7,280	2,361	30,495	2,759,639
7	July	1,354,650	1,060,788	523,059	8,552	2,493	32,647	2,982,189
8	August	1,251,349	992,583	617,298	9,298	2,825	32,973	2,906,327
9	September	903,530	971,512	638,310	10,840	2,997	31,595	2,558,784
10	October	885,186	909,124	667,390	12,670	3,110	28,283	2,505,763
11	November	943,145	865,768	661,470	14,095	2,309	29,348	2,516,135
12	December	1,143,604	941,544	611,217	15,174	952	30,522	2,743,014
13	Annual	12,585,492	11,279,135	7,420,984	132,915	32,243	360,875	31,811,643

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2022 Forecast of Calendar ROA Service Electric Deliveries
(MWh)

Case No.: U-21048
Exhibit No.: A-2 (EMB-1)
Page: 3 of 3
Witness: EMBreuring
Date: September 2021

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Month	Residential	Commercial	Industrial	Street Lighting	Inter-departmental	Wholesale	Total
1	January	-	80,392	219,150	-	-	-	299,542
2	February	-	72,423	194,880	-	-	-	267,303
3	March	-	77,722	213,761	-	-	-	291,483
4	April	-	68,108	214,130	-	-	-	282,239
5	May	-	80,940	217,829	-	-	-	298,769
6	June	-	85,317	234,823	-	-	-	320,140
7	July	-	85,893	227,858	-	-	-	313,752
8	August	-	88,014	251,076	-	-	-	339,090
9	September	-	83,000	226,301	-	-	-	309,302
10	October	-	84,130	230,115	-	-	-	314,246
11	November	-	70,739	210,421	-	-	-	281,159
12	December	-	76,650	212,793	-	-	-	289,443
13	Annual	-	953,329	2,653,138	-	-	-	3,606,467

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

Case No.: U-21048
Exhibit No.: A-3 (EMB-2)
Page: 1 of 1
Witness: EMBreuring
Date: September 2021

Line No.	Description	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	Total Deliveries					
2	Residential	12,585,492	12,576,131	12,809,400	12,715,349	13,122,178
3	Commercial	12,232,465	12,230,512	11,950,362	11,701,907	11,853,553
4	Industrial	10,074,122	10,292,836	10,256,360	10,189,059	11,019,883
5	Street Lighting	132,915	132,915	132,915	132,915	132,915
6	Interdepartmental	32,243	32,280	32,333	32,313	32,228
7	Wholesale	360,875	362,440	364,017	-	-
8	Total Deliveries	35,418,111	35,627,114	35,545,387	34,771,542	36,160,757
9	Total Full Service					
10	Residential	12,585,492	12,576,131	12,809,400	12,715,349	13,122,178
11	Commercial	11,279,135	11,266,491	11,009,280	10,777,485	10,917,172
12	Industrial	7,420,984	7,532,984	7,510,539	7,450,812	8,110,250
13	Street Lighting	132,915	132,915	132,915	132,915	132,915
14	Interdepartmental	32,243	32,280	32,333	32,313	32,228
15	Wholesale	360,875	362,440	364,017	-	-
16	Total Full Service	31,811,643	31,903,241	31,858,484	31,108,874	32,314,743
17	Total ROA Service					
18	Residential	-	-	-	-	-
19	Commercial	953,329	964,022	941,082	924,422	936,381
20	Industrial	2,653,138	2,759,852	2,745,821	2,738,247	2,909,633
21	Street Lighting	-	-	-	-	-
22	Interdepartmental	-	-	-	-	-
23	Wholesale	-	-	-	-	-
24	Total ROA Service	3,606,467	3,723,874	3,686,903	3,662,669	3,846,014

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

Case No.: U-21048
Exhibit No.: A-4 (EMB-3)
Page: 1 of 3
Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	3,336,404	3,320,457	3,303,386	3,232,627	3,206,153
2	February	3,037,501	3,001,047	3,041,419	2,923,348	2,893,247
3	March	3,118,114	3,134,789	3,120,374	3,053,388	3,042,777
4	April	2,869,654	2,889,471	2,879,010	2,817,911	2,789,374
5	May	2,998,533	3,021,895	3,008,213	2,944,223	2,927,345
6	June	3,314,984	3,289,563	3,274,827	3,205,132	3,185,960
7	July	3,540,027	3,584,712	3,567,878	3,491,792	3,471,398
8	August	3,486,873	3,522,298	3,506,947	3,431,237	3,407,947
9	September	3,082,320	3,117,528	3,103,415	3,037,621	2,998,777
10	October	3,032,510	3,067,167	3,053,384	2,988,407	2,965,950
11	November	3,008,271	3,031,903	3,018,400	2,954,157	2,930,171
12	December	3,260,328	3,282,386	3,270,810	3,201,026	3,182,083
13	Annual	38,085,518	38,263,216	38,148,063	37,280,869	37,001,185

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

Case No.: U-21048
Exhibit No.: A-4 (EMB-3)
Page: 2 of 3
Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	3,011,768	2,985,765	2,968,867	2,902,948	2,856,630
2	February	2,747,804	2,702,289	2,743,386	2,629,679	2,581,801
3	March	2,802,212	2,807,509	2,795,018	2,732,455	2,703,334
4	April	2,563,770	2,559,009	2,551,022	2,493,619	2,447,430
5	May	2,674,735	2,682,809	2,672,327	2,612,290	2,577,643
6	June	2,968,025	2,932,578	2,921,316	2,856,011	2,818,009
7	July	3,199,991	3,236,072	3,222,935	3,151,059	3,112,535
8	August	3,119,375	3,144,138	3,133,791	3,062,407	3,019,882
9	September	2,747,107	2,772,637	2,763,435	2,701,432	2,644,896
10	October	2,691,938	2,717,441	2,708,913	2,647,705	2,607,589
11	November	2,703,557	2,719,087	2,710,367	2,649,288	2,609,697
12	December	2,946,636	2,968,037	2,960,909	2,872,464	2,848,174
13	Annual	34,176,916	34,227,371	34,152,286	33,311,358	32,827,620

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

Case No.: U-21048
Exhibit No.: A-4 (EMB-3)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	324,637	334,692	334,519	329,679	349,523
2	February	289,696	298,758	298,033	293,669	311,446
3	March	315,902	327,280	325,357	320,934	339,443
4	April	305,884	330,461	327,988	324,293	341,944
5	May	323,798	339,086	335,886	331,933	349,703
6	June	346,960	356,985	353,511	349,120	367,951
7	July	340,036	348,640	344,943	340,733	358,863
8	August	367,498	378,160	373,156	368,830	388,066
9	September	335,214	344,891	339,980	336,189	353,881
10	October	340,572	349,726	344,471	340,702	358,362
11	November	304,714	312,816	308,033	304,868	320,474
12	December	313,692	314,349	309,901	328,562	333,909
13	Annual	3,908,602	4,035,844	3,995,777	3,969,512	4,173,565

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

Case No.: U-21048
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	5,513	5,613	5,565	5,496	5,341
2	February	5,240	5,330	5,418	5,195	5,025
3	March	5,169	5,363	5,334	5,246	5,104
4	April	4,986	4,876	4,961	4,806	5,121
5	May	5,668	5,729	5,722	5,620	5,588
6	June	7,122	7,143	7,158	7,088	7,038
7	July	7,650	7,680	7,685	7,597	7,547
8	August	7,161	7,196	7,194	7,097	7,047
9	September	6,744	6,803	6,800	6,710	6,661
10	October	5,209	5,409	5,397	5,302	5,130
11	November	5,238	5,403	5,386	5,281	5,117
12	December	5,554	5,709	5,698	5,594	5,457
13	Peak Demand	7,650	7,680	7,685	7,597	7,547

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

Case No.: U-21048
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	5,047	5,132	5,163	5,022	4,867
2	February	4,786	4,815	4,970	4,735	4,566
3	March	4,720	4,898	4,872	4,790	4,651
4	April	4,460	4,393	4,449	4,332	4,650
5	May	5,174	5,208	5,224	5,110	5,083
6	June	6,598	6,610	6,624	6,561	6,516
7	July	7,147	7,168	7,178	7,096	7,051
8	August	6,630	6,647	6,652	6,562	6,519
9	September	6,233	6,279	6,283	6,199	6,158
10	October	4,712	4,898	4,894	4,805	4,640
11	November	4,831	4,989	4,929	4,877	4,720
12	December	5,105	5,262	5,260	5,126	4,996
13	Peak Demand	7,147	7,168	7,178	7,096	7,051

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

Case No.: U-21048
Exhibit No.: A-5 (EMB-4)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	January	466	481	402	474	474
2	February	454	515	448	460	459
3	March	449	465	462	456	453
4	April	526	483	512	474	471
5	May	494	521	498	510	505
6	June	524	533	534	528	522
7	July	503	512	507	501	495
8	August	530	549	542	535	528
9	September	511	524	517	511	504
10	October	496	511	503	497	490
11	November	407	414	457	403	397
12	December	449	447	438	467	461
13	Peak Demand	530	549	542	535	528

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

Case No.: U-21048
Exhibit No.: A-6 (EMB-5)

Witness: EMBreuring
Date: September 2021

Line No.	Month	(a) 2022	(b) 2023	(c) 2024	(d) 2025	(e) 2026
1	Total Deliveries (GWh)	35,418	35,627	35,545	34,772	36,161
2	System Efficiency (%)	93.0%	93.1%	93.2%	93.3%	97.7%
3	Generation Requirements (GWh)	38,086	38,263	38,148	37,281	37,001
4	Summer Peak Demand (MW)	7,650	7,680	7,685	7,597	7,547
5	System Load Factor (%)	56.8%	56.9%	56.7%	56.0%	56.0%

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	)	Case No. U-21048
12 months ending December 31, 2022	)	
______________________________________	)	

DIRECT TESTIMONY

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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 Senior Engineer in the Electric Supply Operations and Power Supply Cost Recovery ("PSCR") Section of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please briefly describe your educational background.

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

Q. Please describe your business and professional experience.

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

Q. What are your present responsibilities and duties as a Senior 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 MPSC?

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; and
- Case No. U-21009 2020 Renewable Energy Reconciliation case.

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

A. The purpose of my direct testimony is to forecast costs of fuel and purchased and net interchange power needed to fulfill the Company's system requirements for 2022 through 2026 in support of the Company's 2022 PSCR Plan.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring:

Exhibit A-7 (JWH-1)	Monthly Summary of the Projected 2022 Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-8 (JWH-2)	Annual Summary for Years 2022 through 2026 of Fuel and Purchased and Net Interchange Power Expenses;
Exhibit A-9 (JWH-3)	Purchased Power Agreements – Projected 2022 Rates; and
Exhibit A-10 (JWH-4)	Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRCs).

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

A. Yes, they were.

<u>POWER SUPPLY COSTS</u>

Q. What are the Company's forecasts of 2022 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 2022?

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 fuel and purchased and net interchange power. This 2022 forecast was produced using up-to-date assumptions and data that were reviewed by the responsible departments before they were 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 2021 PSCR Plan case, Case No. U-20802?

A. Yes. I used the PROMOD IV Production Costing program for this case.

Q. Have there been any major changes to the PROMOD IV model used to develop the fuel and purchased and net interchange power and expenses shown in Exhibits A-7 (JWH-1) and A-8 (JWH-2)?

A. No.

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 2022. Total system requirements (expressed in units of MWh) are shown on page 1, line 13; 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 26. Page 1, lines 27 through 32, present the fixed and capacity-related costs included in PSCR expense. Additional information about page 1, lines 27 through 32, is provided in more detail below. Page 1, line 41 presents the expenses attributed to the Long-Term Industrial Load Retention 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 2022. These pages detail the expenses associated with purchases from (i) Non-Utility Generators

("NUGs") and (ii) utilities and markets shown in the "Purchased (NUGs)" and "Net Interchange" categories shown on Exhibit A-7 (JWH-1), page 1.

Line 34 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 35 and 37 through 39 on Exhibits A-7 (JWH-1) and A-8 (JWH-2) are taken from Company witness Norman J. Kapala's Exhibits A-13 (NJK-3) through A-16 (NJK-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 Zonal Resource Credits ("ZRCs") purchased through bi-lateral agreements. 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 27.

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 28, 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 18.

Exhibit A-7 (JWH-1), page 1, line 29, provides the capacity-related payments associated with the Palisades Nuclear Power Plant ("Palisades") Power Purchase Agreement ("PPA"), as identified in the contract for energy and capacity. The projected energy delivered and non-capacity-related expenses for the Palisades PPA are shown on Exhibit A-7 (JWH-1), page 1, lines 3 and 16, respectively.

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 are included in the Company’s rates based on the amount of cost allowed to be transferred from the Company’s Incremental Cost of Compliance 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 24. Capacity or fixed cost-related expense for the Company’s PPAs (excluding the Palisades PPA) is shown on page 1, lines 30 and 31.

Q. How were these figures derived?

A. They were derived from PROMOD IV, 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 2022, which were then totaled to obtain the annual results that are also shown on Exhibit A-8 (JWH-2), along with the years 2023 through 2026. The main inputs to PROMOD IV 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 PROMOD IV 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. 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 Kapala. 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. Two new Company owned renewable facilities are included. The first is the 201 MW wind facility Heartland Wind Farm, which has a Commercial Operation Date ("COD") of December 31, 2022. The second is the 150 MW solar facility Mustang Mile Solar Project, which has a COD of December 31, 2022.

Four additional solar blocks are included and modeled as four units. The first two units reflect the additions of solar generation consistent with the Company's Proposed Course of Action ("PCA") from its 2018 Integrated Resource Plan ("IRP") approved in June of 2019. The solar generation additions from the PCA are assumed to be 50% Company owned and 50% PPAs. The 2018 IRP PCA called for a 300 MW block with a COD of June 1, 2023 and a 500 MW block with a COD of June 1, 2024. The second two units reflect the additions of solar generation consistent with the Company's PCA from the 2021 IRP which was filed in June 2021. As with the 2018 IRP, the solar generation additions from the 2021 IRP PCA are assumed to be 50% Company owned and 50% PPAs. The 2021 IRP PCA called for a 500 MW block with a COD of June 1, 2025 and a 204 MW block with a COD of June 1, 2026. To reflect the assumption that only 50% of the additions are Company owned, a 150 MW block with a COD of June 1, 2023, a 250 MW block with a COD of June 1, 2024, a 250 MW block with a COD of June 1, 2025, and a 102 MW block with a COD of June 1, 2026 have been added as Company owned resources in the model.

Four natural gas-fired facilities have been added as Company owned assets consistent with the 2021 IRP PCA. The first is the Covert Generating Facility, which is a 1,176 MW facility with an ownership date of June 1, 2023. The next three, all with an ownership date of June 1, 2025, are Dearborn Industrial Generation ("DIG"), a 770 MW facility; Kalamazoo River Generation Station, a 75 MW facility; and Livingston Generating Station, a 132 MW facility.

The gas and oil fired generating units Karn 3 and Karn 4 retirement dates have been changed to May 31, 2023 to align with the Company's 2021 IRP PCA.

The coal fired generating units Campbell 1, Campbell 2, and Campbell 3 retirement dates have been changed to May 31, 2025 to align with the Company's 2021 IRP PCA.

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 PROMOD IV?

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, a price per pound of NO_x emissions was applied as a dispatch fee (when necessary) so that the facility does not exceed the state air permit limit of 683 tons of NO_X emissions in each calendar year.

[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. 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. On Exhibit A-7 (JWH-1), page 1, line 4, you use the term "Station Power." Please explain that term.

A. Station Power is the amount of electricity that a generating unit uses to operate its own generating unit components such as motors, pumps, lighting, heating, etc. When a generating unit is operating, all of the Station Power is subtracted from the gross output of the generating unit to provide the net output that is reported on Exhibit A-7 (JWH-1), page 1, lines 1 and 2. When a generating unit is offline, Station Power usage is accounted for as negative generation. Exhibit A-7 (JWH-1), page 1, lines 1 and 2, reflect the steam generation after subtracting the forecasted Station Power used during periods where units are offline. The total system requirement on Exhibit A-7 (JWH-1), page 1, line 13, includes Station Power used while offline, so I show a separate line item, line 4, to balance the exhibit.

<u>POWER PURCHASE AGREEMENTS</u>

Q. On Exhibit A-7 (JWH-1), page 1, line 11, you use the term "Purchased (NUGs)." Please explain that term.

A. That term refers to forecasted purchases of energy and capacity from NUGs with whom the Company has PPAs. A list of the entities from which power is projected to be purchased for the years 2022 through 2026 is found on Exhibit A-9 (JWH-3), pages 1 through 11, 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, we have 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 our 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. Calhoun Solar, a 140 MW contract, has been added with a COD of 5/31/2022 as well as a 10 MW proxy unit also with a COD of 5/31/2022. This replaced the first PCA proxy unit from the 2018 IRP. 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. Four additional solar blocks are included and modeled as four units. The first two units reflect the additions of solar generation consistent with the Company's PCA from its 2018 IRP. The solar generation additions from the PCA are assumed to be 50% Company owned and 50% PPAs. The 2018 IRP PCA called for a 300 MW block with a COD of June 1, 2023 and a 500 MW block with a COD of June 1, 2024. The second two units reflect the additions of solar generation consistent with the Company's PCA from the 2021 IRP which was filed in June 2021. As with the 2018 IRP, the solar generation additions from the 2021 IRP PCA are assumed to be 50% Company owned and 50% PPAs. The 2021 IRP PCA called for a 500 MW block with a COD of June 1, 2025, and a 204 MW block with a COD of June 1, 2026. To reflect the assumption that only 50% of the additions are PPAs, a 150 MW block with a COD of June 1, 2023, a 250 MW block with a COD of June 1, 2024, a 250 MW block with a COD of June 1, 2025, and a 102 MW block with a COD of June 1, 2026 have been added as PPAs in the model.

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 of the Green Generation contracts that is recoverable in the PSCR is 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-20525, 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 $1,956,000 and the projected customer benefit (offset to PSCR) is $768,000. These amounts are included as credits on Exhibit A-7 (JWH-1) and Exhibit A-8 (JWH-2), page 1, line 24, and page 3, line 53.

Q. Please explain Exhibit A-7 (JWH-1), page 3, line 54.

A. Line 54 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 12, 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 also on Exhibit A-8 (JWH-2), pages 2 and 3. Exhibit A-7 (JWH-1), page 2, lines 43 and 44, detail the energy received and Exhibit A-7 (JWH-1), page 2, lines 47 through 49, detail the energy delivered. Exhibit A-7 (JWH-1), page 3, lines 51 and 52, detail the costs for energy received and page 3, lines 56 through 59, detail the revenues for energy delivered.

Q. Please explain Exhibit A-7 (JWH-1), page 2, line 48, and page 3, line 58.

A. Page 2, line 48, and page 3, line 58, represent a sale to the Energy Market from the Company-owned oil and gas units. This is an estimate of the sale associated with the MISO Reliability Assessment Commitment process. MISO must ensure that sufficient resources are available and online to meet the forecasted MISO load for each hour of the next operating day. We have estimated the amount of increased generation at the oil and gas units that MISO uses for this purpose on page 2, line 48 and have represented it as a sale. The Company will be reimbursed in full for this use of our units and, therefore, this increased generation cost is fully offset by the revenue shown on page 2, line 58 and, as a result, does not affect the PSCR factor.

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

A. Page 3, line 57, 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.

CAPACITY PLANNING RESERVE MARGIN TARGET

Q. What is a capacity planning reserve margin target?

A. The capacity planning reserve margin target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to assure that sufficient capacity exists to provide adequate electric supply in each Planning Year ("PY") period. MISO's PY begins on June 1st of each year and concludes on May 31st of the following calendar year. For example, PY 2022 is the time period from June 1, 2022 through May 31, 2023. Generally, the capacity planning reserve margin target is designed to include consideration of demand forecast variances, generator forced outages and derates,[3] and transmission import limitations.

Q. How does the Company determine the capacity planning reserve margin target?

A. The Company relies on MISO to determine the appropriate capacity planning reserve margin that Consumers Energy should maintain. For PY 2021, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. Upon determining the amount of generation resources that would be necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

Q. What capacity planning reserve margin target is appropriate for the planning period?

A. For PY 2021, MISO staff, with consultation by the LOLE Working Group, determined that, using capacity discounted for forced outages, a capacity planning reserve margin target (or "unforced" capacity planning reserve margin target) for MISO of at least 9.4% of the Company's demand at the time of MISO's coincident peak demand was sufficient to satisfy ReliabilityFirst Corporation's ("RF") capacity planning criteria of expecting to interrupt firm load no more frequently than one occasion in ten years. For PY 2022, MISO staff with consultation by the LOLE Working Group determined that, using capacity discounted for forced outages, a capacity planning reserve margin target for MISO of at least 8.7% of each LSE's demand at the time of MISO's coincident peak demand was

3 MISO addresses generator forced outages and derates by discounting the generator capacity value used in achieving the capacity planning reserve margin target and, thus, excludes forced outages and derates from the actual target.

sufficient to satisfy RF's capacity planning criteria.[4] RF is the regional reliability organization that represents the North American Electric Reliability Corporation ("NERC") in portions of the MISO footprint and portions of the area served by other regional transmission organizations. NERC is the electric reliability organization appointed by the Federal Energy Regulatory Commission ("FERC") to establish, monitor, and enforce reliability standards in the United States. On September 7, 2021, MISO's LOLE Working Group projected planning reserve margin targets of 8.7% for PY 2022, 7.4% for PY 2025, and 7.5% for PY 2027. The Company has interpolated these values and rounded to the nearest tenth of a percent to project a planning reserve margin target of 8.3% for PY 2023, 7.8% for PY 2024, and 7.4% for PY 2026 as shown on line 7 of Exhibit A-10 (JWH-4).

Q. How is Consumers Energy planning to meet the 9.4% planning reserve margin target for the first five months of 2022 and 8.7% for the last seven months of 2022?

A. To facilitate compliance with the planning reserve margin target, MISO has established ZRCs for each PY, which are a measure of a resource's available capacity after discounting for the resource's effective forced outage rate. One ZRC of capacity is expected to be sufficient to serve one MW of forecasted demand, providing an appropriate discount for generator forced outages or effective load carrying capability. Within MISO's footprint, Consumers Energy, as an LSE, is required to comply with the appropriate unforced capacity reserve margin requirement by having ZRCs equal to annual firm peak demand at the time of MISO's coincident peak demand times 1.094 for the five months ending

[4] September 7, 2021 LOLE meeting: https://cdn.misoenergy.org/20210907%20LOLEWG%20Item%2003%20PY%202022-23%20Preliminary%20LOLE%20Study%20Results586120.pdf

May 31, 2022 and annual firm peak demand at the time of MISO's coincident peak demand times 1.087 for the seven months beginning June 1, 2022. This amount of capacity provides an adequate reserve to cover load forecast error, weather variability, and transmission contingencies while considering the benefits that result from demand diversity over the MISO footprint. ZRCs eliminate the potential for double-counting MISO market participants' resources within the MISO market footprint through tariff requirements on market participants to use the Module E Capacity Tracking tool.

Q. How does the Company determine the amount of ZRCs needed for the peak demand season and the corresponding MISO PY?

A. To determine the amount of ZRCs represented by the capacity planning/reserve margin target, the Company utilizes the demand forecast discussed in the direct testimony of Company witness Breuring. The forecasted bundled non-coincident peak demand for PY 2022 is 7,768 MW, shown on line 1 of Exhibit A-10 (JWH-4), and the internal demand response ("DR") programs adjust the peak downward by 877 MW, shown on line 2 of Exhibit A-10 (JWH-4), for an adjusted non-coincident peak demand of 6,891 MW, shown on line 3 of Exhibit A-10 (JWH-4). However, because the Company's peak demand traditionally occurs at a period different than MISO's peak demand, capacity requirements are reduced based on the Company's demand coincident with MISO's peak demand. Historical data of the Company's demand at the time of MISO's peak demand indicates that this diversity in peak demand periods reduces the Company's requirements by a load diversity factor of 96.43%, shown on line 4 of Exhibit A-10 (JWH-4). The resulting coincident peak demand of 6,645 MW is shown on line 5 of Exhibit A-10 (JWH-4). A second adjustment is needed in order to convert this load from demand at the distribution level to the generation level which is accomplished by multiplying this load by a transmission loss factor of 1.035.[5] The final adjustment made is to apply the planning reserve margin target percentage. Total Planning Reserve Margin Requirement ("PRMR"), as shown on line 8 of Exhibit A-10 (JWH-4), is then calculated by increasing the bundled coincident peak demand by transmission losses and planning reserve margin which results in 7,476 ZRCs in PY 2022.

Q. What programs are included in internal DR programs shown on line 2 of Exhibit A-10 (JWH-4)?

A. Internal DR programs include Energy Efficiency ("EE"), Dynamic Peak Pricing ("DPP") programs (consisting of Peak Time Rewards ("PTR") and Critical Peak Pricing ("CPP")), Summer Peak Rate, and Conservation Voltage Reduction ("CVR").

Q. How is the PY 2022 forecasted non-coincident peak demand of 7,768 MW shown on line 1 of Exhibit A-10 (JWH-4) derived from the demand forecast discussed in the direct testimony of Company witness Breuring?

A. Mr. Breuring's forecast of 7,650 MW of demand shown on Exhibit A-5 (EMB-4), page 1, line 7 occurs in July 2022 and includes jurisdictional and non-jurisdictional demand from the Company's distribution and wholesale customers adjusted for the demand expected to be offset by EE, DPP, Summer Peak Rate, and CVR at the time of the Company's peak demand. The demand expected to be offset by EE, DPP, Summer Peak Rate, and CVR amounts to 908 MW at the time of the Company's 2022 peak demand. Adding that amount to the 7,650 MW provided by Mr. Breuring provides a gross demand of 8,558 MW; however, because this load is at the generation level it must be reduced by the transmission

[5] 2022-2023 Transmission Loss Percentage.xlsx: https://www.misoenergy.org/planning/resource-adequacy

loss factor previously mentioned, resulting in 8,268 MW of gross demand. Mr. Breuring also prepares an estimate of the amount of demand expected to be offset by Retail Open Access ("ROA") suppliers of 503 MW at the time of the Company's peak demand as shown on Exhibit A-5 (EMB-4), page 3, line 7. However, for the Planning Resource Auction ("PRA"), MISO calculates the forecasted peak demand to be offset by ROA suppliers differently, where current year ROA is equal to the previous year's ratio of ROA to System Peak Load multiplied by the current year's System Peak Load. As before, this load is at the generation level and is converted to the distribution level by reducing by the transmission loss factor. An estimate for the amount of demand expected to be offset by ROA suppliers is 500 MW at the time of the Company's peak demand. Subtracting this ROA load from 8,268 MW results in the forecasted non-coincident peak demand at the distribution level of 7,768 MW as shown on line 1 of Exhibit A-10 (JWH-4).

RESOURCES PLANNED TO SATISFY RESERVE MARGIN REQUIREMENT

Q. What resources are required to meet the 9.4% planning reserve margin target for the first five months of 2022 and 8.7% for the last seven months of 2022?

A. Lines 9 through 31 of Exhibit A-10 (JWH-4) provide a description of the resources currently available to the Company and the resources that are expected to be acquired by Consumers Energy to achieve the 8.7% capacity planning reserve margin under peak load conditions of 2022. In 2022, the Company expects to have 5,088 ZRCs from owned units during the peak load period (Consumers Energy is a summer-peaking system), as shown on line 17 of Exhibit A-10 (JWH-4). The Company is able to provide ZRCs in the form of load modifying resources, including Peak Power Savers Air Conditioning Peak Cycling ("ACPC"), Commercial and Industrial DR ("C&I DR"), Smart Thermostat, the Company's

Energy Intensive Primary tariff ("Rate EIP"), and the Company's interruptible service provision ("Rate GI"). MISO regards these load modifying resources as resources not requiring a reserve margin to be maintained and, therefore, will be awarded ZRCs equal to the equivalent generating capacity[6] times one plus the reserve margin requirement or, in this case, 604 ZRCs shown on line 18 of Exhibit A-10 (JWH-4). The Company also has long-term contracts with several NUGs for a total of 1,834 ZRCs, as shown on line 31 of Exhibit A-10 (JWH-4). The compilation of all resources for PY 2022 totaling 7,525 ZRCs, as shown on line 32 of Exhibit A-10 (JWH-4), when compared to the PRMR of 7,476 MW provides an unforced capacity surplus of 49 ZRCs, as shown on line 33 of Exhibit A-10 (JWH-4).

RESOURCES PREVIOUSLY APPROVED BY THE COMMISSION

Q. To what extent have the owned resources and NUG resources providing ZRCs in 2022 been included in previous PSCR Plans and/or the IRP?

A. Owned and NUG resources have been included in previous PSCR plans, most recently in MPSC Case No. U-20802. While the Commission has yet to conclude its consideration of the PSCR Plan presented in MPSC Case No. U-20802, most of the resources included in this PSCR Plan were included in the last PSCR Plan. The resources included pursuant to the approved 2018 IRP are discussed above. The Commission's February 22, 2018 Order in Case No. U-18090 directed the Company to execute 150 MW of additional capacity through new PURPA contracts with QFs in the "PURPA queue." This amount was then increased to 584 MW as part of the 2018 IRP settlement approved by the Commission in

[6] The equivalent generation capacity is equal to customer demand multiplied by the sum of one plus transmission losses.

Case No. U-20615 and the Company expects all 584 MW to be available for PY 2025, as shown on column (d), line 28 of Exhibit A-10 (JWH-4).

RESOURCES NOT PREVIOUSLY APPROVED BY THE COMMISSION

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

A. Yes, resources included in the Company's IRP and PPA resources.

Q. What resources are included as part of the Company's IRP?

A. As discussed above, the 2021 IRP PCA includes a 500 MW block of solar with a COD of June 1, 2025, and a 204 MW block of solar with a COD of June 1, 2026, which are assumed to be 50% owned and 50% PPA.

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

A. The PPA resources included in this PSCR Plan that have not been previously approved by the Commission are addressed in the direct testimony of Company witness Emily M. Walainis.

RESOURCES REMAINING TO BE PURCHASED FOR 2022

Q. Does Consumers Energy need to acquire additional capacity for 2022?

A. No.

<u>MISO CAPACITY MARKET</u>

Q. What are the Company's options for meeting its PRMR?

A. The Company can meet its PRMR by the tariffs and procedures established by MISO. MISO Business Practice Manual 11[7] explains how to obtain capacity for resources and how to fulfill PRMR obligations.

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 on a daily basis over the course of the PY and are recovered through annual PSCR reconciliations.

Q. Does this conclude your direct testimony?

A. Yes.

[7] MISO BPM 11: https://www.misoenergy.org/legal/business-practice-manuals/.

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, 2022	))))))	Case No. U-21048

EXHIBITS

OF

JOSHUA W. HAHN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

MICHIGAN PUBLIC SERVICE COMMISSION

Case No.: U-21048
Exhibit No.: A-7 (JWH-1)
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Witness: JWHahn
Date: September 2021

CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2022
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	ENERGY (MWH)													
1	COAL STEAM	1,156,349	1,041,451	1,053,072	587,170	857,001	1,096,282	1,178,267	1,172,112	1,109,077	791,239	952,100	1,188,141	12,182,261
2	GAS & OIL	656,341	618,987	553,332	452,425	375,780	502,925	633,324	588,396	546,995	466,130	602,283	649,295	6,646,214
3	NUCLEAR PPA	605,196	544,922	590,415	565,344	578,880	0	0	0	0	0	0	0	2,884,757
4	STATION POWER	4,710	4,254	5,609	11,304	7,633	4,349	3,614	4,710	4,800	11,579	7,602	4,710	74,872
5	CE OWNED RENEWABLES	240,261	205,365	278,136	231,254	202,751	152,670	130,016	124,575	144,531	192,252	211,279	235,419	2,348,510
6	PEAKERS	116,928	116,024	35,167	72,926	50,848	55,588	104,493	88,168	76,773	79,982	18,157	89,666	904,719
7	PUMPED STORAGE	148,624	124,782	150,037	72,748	75,583	143,940	159,263	177,320	151,513	86,224	123,053	128,925	1,542,012
8	TOTAL GENERATED	2,928,408	2,655,784	2,665,768	1,993,172	2,148,476	1,955,754	2,208,978	2,155,281	2,033,690	1,627,406	1,914,474	2,296,156	26,583,345
9	LESS : PUMPING	-196,639	-158,486	-199,719	-93,732	-97,336	-189,897	-207,994	-222,870	-197,928	-117,001	-160,983	-162,615	-2,005,199
10	TOTAL GENERATED	2,731,769	2,497,298	2,466,049	1,899,440	2,051,140	1,765,857	2,000,984	1,932,411	1,835,761	1,510,405	1,753,491	2,133,541	24,578,147
11	PURCHASED (NUGs)	871,592	821,477	761,438	856,758	864,443	822,311	975,974	921,919	812,037	822,930	710,273	671,299	9,912,449
12	NET INTERCHANGE	-591,595	-570,972	-425,271	-192,431	-240,853	379,856	214,145	262,821	99,309	358,591	239,778	141,790	-324,834
13	**TOTAL SYSTEM REQUIREMENTS**	3,011,765	2,747,803	2,802,216	2,563,767	2,674,730	2,968,024	3,191,103	3,117,152	2,747,107	2,691,925	2,703,542	2,946,629	34,165,762
	VARIABLE EXPENSES ($*1000)													
14	COAL STEAM	26,120	23,540	24,108	13,609	19,671	24,792	26,495	26,335	25,080	17,711	21,381	26,713	275,556
15	GAS & OIL	23,642	21,874	18,047	12,540	10,940	14,522	19,841	16,717	15,402	13,629	17,059	18,481	202,695
16	NUCLEAR PPA VARIABLE	4,866	3,813	4,045	694	241	0	0	0	0	0	0	0	13,659
17	STATION POWER	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CE OWNED RENEWABLES	9,532	7,996	10,488	7,645	6,646	5,148	5,204	5,127	5,133	6,991	7,618	8,676	86,204
19	PEAKERS	5,160	5,055	1,536	2,613	1,768	1,974	3,666	3,107	2,649	2,790	762	3,696	34,776
20	PUMPED STORAGE	0	0	0	0	0	0	0	0	0	0	0	0	0
21	TOTAL GENERATED	69,321	62,278	58,223	37,102	39,267	46,436	55,206	51,285	48,265	41,121	46,820	57,566	612,890
22	LESS : PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0
23	TOTAL GENERATED	69,321	62,278	58,223	37,102	39,267	46,436	55,206	51,285	48,265	41,121	46,820	57,566	612,890
24	PURCHASED (NUGs) VARIABLE COST[1]	42,121	39,548	34,504	36,240	35,928	34,721	42,086	39,760	32,229	30,516	25,930	24,057	417,641
25	NET INTERCHANGE, EXCLUDING ZRC	-34,639	-31,699	-18,917	-7,159	-9,140	7,825	-265	3,427	-1,134	9,675	6,665	3,790	-71,573
		0												
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**76,803**	**70,127**	**73,810**	**66,183**	**66,055**	**88,981**	**97,027**	**94,472**	**79,359**	**81,312**	**79,416**	**85,413**	**958,958**
27	ZONAL RESOURCE CREDIT PURCHASE	0	0	0	0	0	0	0	0	0	0	0	0	0
28	OWNED RENEWABLE CAPACITY	5,553	4,658	6,109	4,454	3,871	2,999	3,031	2,986	2,990	4,073	4,438	5,054	50,216
29	NUCLEAR PPA CAPACITY	34,719	27,209	28,859	7,244	5,359	0	0	0	0	0	0	0	103,390
30	PURCHASED (NUG) CAPACITY	23,068	21,174	22,772	22,078	22,865	21,941	22,841	22,763	21,620	21,997	21,030	21,452	265,602
31	PURCHASED (NUG) FIXED ENERGY	7,493	6,859	7,490	5,767	5,976	5,775	5,948	5,948	5,758	5,938	5,778	5,945	74,675
32	INDEPENDENT ADMINISTRATOR EXPENSE	40	40	0	0	0	0	0	0	0	40	40	40	200
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**70,872**	**59,939**	**65,231**	**39,542**	**38,072**	**30,715**	**31,820**	**31,698**	**30,368**	**32,048**	**31,286**	**32,492**	**494,083**
34	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	36,680	34,549	34,274	32,207	36,776	46,251	45,797	42,496	43,582	34,188	34,931	37,099	458,831
35	ACTIVATED CARBON	84	84	84	84	84	84	84	84	84	84	84	84	1,010
36	MISO - SCHEDULE 2 (REACTIVE)	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-375	-4,500
37	AQUEOUS AMMONIA EXPENSE	74	74	74	74	74	74	74	74	74	74	74	74	892
38	UREA EXPENSE	226	226	226	226	226	226	226	226	226	226	226	226	2,711
39	LIME EXPENSE	665	665	665	665	665	665	665	665	665	665	665	665	7,976
40	**TOTAL POWER SUPPLY COSTS**	**185,030**	**165,289**	**173,989**	**138,607**	**141,577**	**166,621**	**175,318**	**169,341**	**153,984**	**148,223**	**146,308**	**155,677**	**1,919,962**
41	LTILRR PAYMENTS	530	932	2,512	1,994	2,796	2,141	-13	1,232	2,991	4,091	1,939	919	22,065
42	**TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS**	**184,500**	**164,356**	**171,477**	**136,612**	**138,781**	**164,480**	**175,331**	**168,108**	**150,993**	**144,131**	**144,369**	**154,759**	**1,897,897**

[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

Case No.: U-21048
Exhibit No.: A-7 (JWH-1)

Witness: JWHahn
Date: September 2021

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2022
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)													
43	MARKET ON PEAK	0	0	7,054	5,133	42,209	203,749	76,413	117,476	87,745	73,636	121,758	114,522	849,695
44	MARKET OFF PEAK	26,262	61,032	60,292	86,255	63,404	363,849	388,871	372,010	283,021	400,501	248,432	209,677	2,563,606
45	PURCHASED (NUGs)	871,592	821,477	761,438	856,758	864,443	822,311	975,974	921,919	812,037	822,930	710,273	671,299	9,912,449
46	TOTAL RECEIVED	897,854	882,509	828,784	948,146	970,055	1,389,908	1,441,259	1,411,405	1,182,803	1,297,066	1,080,463	995,498	13,325,751
	NET INTERCHANGE DELIVERED (MWH)													
47	EXTERNAL SALES	617,858	632,005	492,617	283,820	346,466	184,763	222,791	226,665	271,457	115,546	130,412	182,409	3,706,808
48	MISO RAC	0	0	0	0	0	2,979	28,349	0	0	0	0	0	31,328
49	TOTAL DELIVERED	617,858	632,005	492,617	283,820	346,466	187,742	251,140	226,665	271,457	115,546	130,412	182,409	3,738,136
50	NET (MWH)	279,996	250,505	336,167	664,326	623,589	1,202,167	1,190,119	1,184,740	911,346	1,181,520	950,051	813,089	9,587,615

CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2022
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**	**(j)**	**(k)**	**(l)**	**(m)**	**(n)**	**(o)**
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000)													
51	MARKET ON PEAK ENERGY	837	837	1,103	1,013	2,293	7,623	3,732	5,196	3,837	3,398	5,126	5,023	40,017
52	MARKET OFF PEAK ENERGY	1,101	2,377	1,865	2,351	1,558	8,722	10,892	9,687	7,238	11,054	6,723	6,267	69,835
53	PURCHASED (NUGs) ENERGY	40,870	38,297	33,253	34,989	34,677	33,470	40,835	38,509	30,978	29,265	24,679	22,806	402,628
54	CASE NO. U-16048 COST RECOVERY	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	1,251	15,013
55	TOTAL EXPENSE	44,059	42,762	37,471	39,604	39,780	51,065	56,710	54,643	43,304	44,968	37,780	35,347	527,493
	NET INTERCHANGE CREDIT ($*1000)													
56	EXTERNAL SALE ENERGY	36,577	34,913	21,885	10,523	12,991	8,153	12,285	11,456	12,209	4,777	5,184	7,500	178,455
57	EXTERNAL SALE CAPACITY	0	0	0	0	0	0	0	0	0	0	0	0	0
58	MISO RAC	0	0	0	0	0	366	2,604	0	0	0	0	0	2,970
59	TOTAL CREDIT	36,577	34,913	21,885	10,523	12,991	8,520	14,890	11,456	12,209	4,777	5,184	7,500	181,425
60	NET EXPENSE	7,482	7,849	15,587	29,081	26,788	42,545	41,821	43,187	31,095	40,191	32,595	27,847	346,068

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CONSUMERS ENERGY COMPANY

SUMMARY BY SOURCE

YEAR		2022	2023	2024	2025	2026
(a)	(b)	(c)	(d)	(e)	(f)	(g)
	ENERGY (MWH)					
1	COAL STEAM	12,182,261	10,097,381	8,816,786	2,890,657	0
2	GAS & OIL	6,646,214	11,203,236	15,692,932	18,379,198	19,661,641
3	NUCLEAR PPA	2,884,757	0	0	0	0
4	STATION POWER	74,872	45,403	15,678	16,277	0
5	CE OWNED RENEWABLES	2,348,510	3,210,473	3,587,867	4,014,291	4,290,746
6	PEAKERS	904,719	1,273,830	1,209,255	1,417,715	1,318,155
7	PUMPED STORAGE	1,542,012	1,353,331	1,168,809	912,797	1,105,771
8	TOTAL GENERATED	26,583,345	27,183,653	30,491,327	27,630,935	26,376,313
9	LESS : PUMPING	-2,005,199	-1,762,455	-1,520,142	-1,180,544	-1,427,562
10	TOTAL GENERATED	24,578,147	25,421,198	28,971,185	26,450,391	24,948,751
11	PURCHASED (NUGs)	9,912,449	11,530,231	11,414,845	12,120,900	12,149,406
12	NET INTERCHANGE	-324,834	-2,735,844	-6,245,659	-5,272,005	-4,294,845
13	**TOTAL SYSTEM REQUIREMENTS**	34,165,762	34,215,586	34,140,371	33,299,286	32,803,312
	VARIABLE EXPENSES ($*1000)					
14	COAL STEAM	275,556	234,679	210,418	71,984	301
15	GAS & OIL	202,695	198,058	219,898	244,823	255,482
16	NUCLEAR PPA VARIABLE	13,659	0	0	0	0
17	STATION POWER	0	0	0	0	0
18	CE OWNED RENEWABLES	86,204	106,032	109,516	111,546	113,954
19	PEAKERS	34,776	40,725	35,649	41,368	40,582
20	PUMPED STORAGE	0	0	0	0	0
21	TOTAL GENERATED	612,890	579,493	575,481	469,722	410,319
22	LESS : PUMPING	0	0	0	0	0
23	TOTAL GENERATED	612,890	579,493	575,481	469,722	410,319
24	PURCHASED (NUGs) VARIABLE COST[1]	417,641	452,941	451,230	481,597	502,806
25	NET INTERCHANGE, EXCLUDING ZRC	-71,573	-144,896	-254,468	-259,169	-220,221
26	**TOTAL FUEL, VARIABLE PURCHASED AND NET INTERCHANGE**	**958,958**	**887,538**	**772,243**	**692,150**	**692,904**
27	ZONAL RESOURCE CREDIT PURCHASE	0	0	0	0	0
28	OWNED RENEWABLE CAPACITY	50,216	61,766	63,796	64,979	66,381
29	NUCLEAR PPA CAPACITY	103,390	0	0	0	0
30	PURCHASED (NUG) CAPACITY	265,602	274,017	282,208	275,743	263,517
31	PURCHASED (NUG) FIXED ENERGY	74,675	69,407	71,809	67,514	62,374
32	INDEPENDENT ADMINISTRATOR EXPENSE	200	200	200	200	200
33	**TOTAL CAPACITY AND NUG FIXED COSTS**	**494,083**	**405,390**	**418,014**	**408,436**	**392,472**
34	TOTAL TRANSMISSION AND ENERGY MARKETS ADMINISTRATION	458,831	484,043	510,861	523,233	532,492
35	ACTIVATED CARBON	1,010	927	863	326	0
36	MISO - SCHEDULE 2 (REACTIVE)	-4,500	-4,500	-4,500	-4,500	-4,500
37	AQUEOUS AMMONIA EXPENSE	892	439	186	193	172
38	UREA EXPENSE	2,711	2,801	2,829	868	0
39	LIME EXPENSE	7,976	7,260	6,676	2,313	0
40	**TOTAL POWER SUPPLY COSTS**	**1,919,962**	**1,783,899**	**1,707,172**	**1,623,019**	**1,613,540**
41	LTILRR PAYMENTS	22,065	18,447	13,631	13,201	17,210
42	**TOTAL POWER SUPPLY COSTS LESS LTILRR PAYMENTS**	**1,897,897**	**1,765,452**	**1,693,541**	**1,609,818**	**1,596,331**

[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 co

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CONSUMERS ENERGY COMPANY

PURCHASED AND INTERCHANGE POWER REPORT

YEAR		2022	2023	2024	2025	2026
(a)	(b)	(o)				
	PURCHASED AND NET INTERCHANGE RECEIVED (MWH)					
43	MARKET ON PEAK	849,695	306,208	126,936	208,581	288,306
44	MARKET OFF PEAK	2,563,606	2,711,376	1,596,367	1,566,557	1,602,066
45	PURCHASED (NUGs)	9,912,449	11,530,231	11,414,845	12,120,900	12,149,406
46	TOTAL RECEIVED	13,325,751	14,547,815	13,138,148	13,896,038	14,039,778
	NET INTERCHANGE DELIVERED (MWH)					
47	EXTERNAL SALES	3,706,808	5,753,428	7,968,962	7,047,142	6,185,217
48	MISO RAC	31,328	0	0	0	0
49	TOTAL DELIVERED	3,738,136	5,753,428	7,968,962	7,047,142	6,185,217
50	NET (MWH)	9,587,615	8,794,387	5,169,186	6,848,896	7,854,560

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P U R C H A S E D   A N D   I N T E R C H A N G E   P O W E R   R E P O R T

YEAR		2022	2023	2024	2025	2026
(a)	(b)	(o)				
	VARIABLE PURCHASED AND NET INTERCHANGE EXPENSE ($*1000					
51	MARKET ON PEAK ENERGY	40,017	20,172	12,252	15,856	18,335
52	MARKET OFF PEAK ENERGY	69,835	71,261	37,027	40,521	42,391
53	PURCHASED (NUGs) ENERGY	402,628	437,929	435,660	466,584	488,297
54	CASE NO. U-16048 COST RECOVERY	15,013	15,013	15,570	15,013	14,509
55	TOTAL EXPENSE	527,493	544,375	500,510	537,974	563,532
	NET INTERCHANGE CREDIT ($*1000)					
56	EXTERNAL SALE ENERGY	178,455	236,186	303,684	315,545	280,947
57	EXTERNAL SALE CAPACITY	0	0	0	0	0
58	MISO RAC	2,970	144	64	1	0
59	TOTAL CREDIT	181,425	236,330	303,748	315,546	280,946
60	NET EXPENSE	346,068	308,045	196,762	222,428	282,585

Line	EXISTING ENERGY-ONLY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
1	Great Lakes Tissue Company	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	Michigan State University	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	Western Michigan University	Hourly incremental running cost	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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	Grand Valley State University	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	City of Midland, MI	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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	MAHLE Engine Components USA	90% of (Consumers Energy's Real Time Load Node LMP Minus $5/MWh)	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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	City of Grand Rapids (WWTF)	Real-time LMP	$1/MWh for Delivered Energy		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	Otsego Paper	Real-time LMP	$1/MWh for Delivered Energy		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 $372/month, but not to exceed $3,720/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	North American Natural Resources, Inc. Venice Park Generating Station (Landfill Gas)	Average PSCR rate	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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 Energy, formerly Gas Recovery Systems, LLC. C&C Electric 2 Plant (Landfill Gas)	Average PSCR rate	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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 $372/month, but not to exceed $3,720/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	July 16, 2028. 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.
5	WM Renewable Energy, LLC. (formerly Bio Energy Partners)	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

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
6	Black River Limited Partnership	6.607¢/kWh	0.10¢/kWh (minimum of $200/month, but not to exceed	$11,708.75/ZRC-month	May 31, 2039
7	Beaverton, City of	2.71¢/kWh	0.10¢/kWh	3.51¢/kWh On-Peak, 2.75¢/kWh Off-Peak	December 31, 2023. After this date the Agreement may continue 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.
8	Hope Renewable Energy – Hubbardston	Agreement Terminated.			
9	Commonwealth Power Company – Irving	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.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
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

MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY
PURCHASED POWER AGREEMENTS

PROJECTED 2022 RATES

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
17	Grayling Generating Station Limited Partnership	Twelve-month rolling average cost of CE coal generation	0.10¢/kWh (minimum of $372/month, but not to exceed $3,720/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	Grenfell Hydro, Inc	5.405¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$8768.50/ZRC-month	May 31, 2039.
19	Hillman Power Company LLC	4.0¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$11,708.75/ZRC-month	May 31, 2022 The term of this Power Purchase Agreement shall be the period commencing on the Commercial Operation Date of the Hillman Generating Plant and continuing until May 31, 2022.
20	Kent County	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.

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
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 $372/month, but not to exceed $3,720/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 – Fallasburg Hydro Plant	5.4¢/kWh	0.10¢/kWh (not to exceed $2,000/month)	$8,768.50/ZRC-month	May 31, 2039

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
28	STS Hydropower Ltd – Morrow Hydro Plant	2.71¢/kWh	0.10¢/kWh	3.97¢/kWh On-Peak, 3.37¢/kWh Off-Peak	December 31, 2021. 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.
29	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.
30	STS Hydropower Ltd – Fallasburg Hydro Plant	5.4¢/kWh	None	$4,503/ZRC-month	May 31, 2039.
31	Viking Energy of Lincoln Limited Partnership	4.0¢/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 Lincoln Michigan Plant and continuing until May 31, 2029
32	Viking Energy of McBain Limited Partnership	4.0¢/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

Line	EXISTING ENERGY & CAPACITY AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
33	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.
34	Boyce Hydro (formerly Wolverine Power Corporation)	4.67¢/kWh On-Peak, 3.66¢/kWh Off-Peak	None	2.33¢/kWh On-Peak, 1.97¢/kWh Off-Peak	May 31, 2022.
35	STS Hydropower Ltd – Thornapple Ada Hydro Plant	4.076¢/kWh	None	$11,708.75/ZRC-month	May 31, 2027.
36	Kleber Hydro	6.607¢/kWh	None	None	May 31, 2039.
37	Tower Hydro	6.607¢/kWh	None	None	May 31, 2039.
38	Good Fruits Storage, LLC	LMP	None	PRA	May 31, 2031.
39	Hazel Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
40	Bingham Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
41	Temperance Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
42	13 Mile Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
43	Captain Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
44	Coldwater Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
45	Geddes 1 Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
46	Interchange Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
47	Jack Francis Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
48	May Shannon Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
49	Stoneheart Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
50	Workman Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
51	Arthur Solar Farm	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
52	Golden Solar Farm	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
53	Robert Swift Solar Farm	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
54	Angola Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
55	Geddes 2 Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
56	Bullhead Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.

57	Hendershot Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
58	Hogan Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
59	Byrne Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
60	Entergy Nuclear Power Marketing, LLC	0.664¢/kWh	None	4.736¢/kWh	May 31, 2022.
61	Albion North Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
62	Allegheny Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
63	Aluminum Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
64	Bamboo Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
65	Blue Elk Solar I	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
66	Blue Elk Solar III	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
67	Blue Elk Solar IV	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
68	Blue Elk Solar VII	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
69	Burns Park Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
70	Calhoun Solar Energy LLC	3.747¢/kWh	None	$2,775.83/ZRC-month	May 31, 2042.
71	Cement City Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
72	Cloudbreak Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
73	Congo Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
74	Durban Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
75	Esmarelda Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
76	Greenstone Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
77	Hogan Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
78	Johnsfield Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
79	Letts Creek Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
80	Lightfoot Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
81	Lyons Road Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.

82	Macbeth Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
83	Midcontinent Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
84	NextSun Energy LLC - Lake City Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
85	NextSun Energy LLC - Morey Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
86	NextSun Energy LLC - Surrey Road Solar	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2042.
87	Pullman Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
88	Rosco Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
89	Shady Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
90	Shipsterns Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
91	Surbrook Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
92	Swede Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
93	TART Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2043.
94	Thorn Lake Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
95	Topanga Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
96	Wilford Solar	4.155¢/kWh	None	$739.13/ZRC-month	May 31, 2042.
97	Woodley Solar, LLC	4.155¢/kWh	None	$11,708.75/ZRC-month	May 31, 2041.
98	Elk Rapids Hydroelectric Power LLC	7.068¢/kWh	None	$11,708.75/ZRC-month	May 31, 2039.
99	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.
100	Heathlands Solar LLC	3.835¢/kWh	None	$2,775.83/ZRC-month	May 31, 2042.

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.
Line	RENEWABLE ENERGY PLAN AGREEMENTS	Energy	Administrative Charge	Capacity	Termination of Agreement
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.

Case No:	U-21048
Exhibit No.:	A-10 (JWH-4)
Page:	1 of 1
Witness:	JWHAHN
Date:	September 2021

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

Line	(a)	(a) PY 2022-23	(b) PY 2023-24	(c) PY 2024-25	(d) PY 2025-26	(e) PY 2026-27
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,768	7,861	7,934	7,963	7,993
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	877	931	1,009	1,114	1,187
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	6,891	6,930	6,925	6,849	6,806
4	Load Diversity Factor coincident to MISO, %.	96.43%	96.43%	96.43%	96.43%	96.43%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,645	6,682	6,678	6,605	6,563
6	Transmission Losses, %	3.50%	3.50%	3.50%	3.50%	3.50%
7	Planning Reserve Margin % UCAP Basis	8.70%	8.30%	7.80%	7.40%	7.40%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,476	7,490	7,451	7,342	7,296
9	Company Owned, In-State, Non-Intermittent, ZRC	4,944	4,867	4,865	3,547	3,547
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	115	298	423	999	1,178
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	12	12	12	12	12
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	5,088	5,194	5,316	4,575	4,754
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4)	604	637	641	646	653
19	PPA, In-State, Non-Intermittent, ZRC	1,653	1,653	1,653	1,566	1,566
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	33	33	33	28	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	43	168	293	418	469
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	6	5	5	5	5
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	8	8	8	13	16
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	92	212	222	306	306
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,834	2,079	2,214	2,336	2,387
32	Total Planning Resources, ZRC (line 17 + line 18 + line 31)	7,525	7,909	8,171	7,557	7,794
33	UCAP Surplus/(Shortfall), ZRC (line 32 - line 8)	49	419	721	215	498

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	)	Case No. U-21048
12 months ending December 31, 2022	)	
___________________________________	)	

DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

Q. Please state your name and business address.

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

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

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

Q. Please describe your educational background.

A. In 1996, I received a Bachelor of Science degree in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science degree in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites in 2016, I was promoted to Executive Director of Coal Generation. In April 2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

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

A. Yes. I have sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan ("IRP") under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20526	2020 PSCR Reconciliation; and
Case No. U-20190	2021 IRP.

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 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 2022 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 2016 through 2020; (iv) address availability of generating units for the five-year forecast period; (v) identify forecasted urea expenses for the 2022 PSCR Plan year, as well as the forecast period 2023 through 2026; (vi) identify forecasted aqueous ammonia expenses for the 2022 PSCR Plan year, as well as the forecast period 2023 through 2026; (vii) identify forecasted lime expenses for the 2022 PSCR Plan year, as well as the forecast period 2023 through 2026; and (viii) identify forecasted activated carbon expenses for the 2022 PSCR Plan year, as well as the forecast period 2023 through 2026.

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Exhibit A-11 (NJK-1)	Major Outages in the 2022 PSCR Plan;
Exhibit A-12 (NJK-2)	2022 PSCR Random Outage Rate Projections;
Exhibit A-13 (NJK-3)	2022-2026 Urea Expense;
Exhibit A-14 (NJK-4)	2022-2026 Aqueous Ammonia Expense;
Exhibit A-15 (NJK-5)	2022-2026 Lime Expense; and
Exhibit A-16 (NJK-6)	2022-2026 Activated Carbon Expense.

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

A. Yes.

<u>Major Generating Plant Outages for 2022</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-11 (NJK-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-11 (NJK-1).

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

<u>Campbell Unit 3</u>

The outage at Campbell Unit 3 is scheduled to begin March 28, 2022 and is projected to last for 46 days – concluding May 13, 2022. The outage is necessary for overhaul of the boiler feed pump turbine, pulse jet fabric filter bag and cleaning air manifold replacement, selective catalytic reduction catalyst management, work associated with the Steam Electric Effluent Guidelines ("SEEG"), and CO-O_2 monitor installation. Work such as SEEG can potentially be avoided if the Company's proposal to retire Campbell Unit 3 in 2025 is approved in its 2021 IRP, Case No. U-21090.

<u>Karn Unit 3</u>

The outage at Karn Unit 3 is scheduled to begin September 23, 2022 and is projected to last for 45 days – concluding November 7, 2022. The outage is necessary for the performance of decoupling activities, cooling tower rebuild and replacement of the ductwork expansion join. The need for an outage of this length and the associated performance of this outage work will ultimately depend on the decision that is made in the Company's 2021 IRP, Case No. U-21090. The capital activites could be avoided if the Company's proposal to retire Karn Units 3 and 4 in 2023 coincides with the retirement of Karn Units 1 and 2.

<u>Karn Unit 4</u>

The outage at Karn Unit 4 is scheduled to begin September 23, 2022 and is projected to last for 45 days – concluding November 7, 2022. The outage is necessary for the performance of decoupling activities, replacement of the cooling tower riser, and replacement of the static exciter controls. The need for an outage of this length and the associated performance of this outage work will ultimately depend on the decision that is made in the Company's 2021 IRP, Case No. U-21090. These capital activites could be avoided if the Company's proposal to retire Karn Units 3 and 4 in 2023 coincides with the retirement of Karn Units 1 and 2.

Campbell Unit 2

The outage at Campbell Unit 2 is scheduled to begin September 29, 2022 and is projected to last for 42 days – concluding November 10, 2022. The periodic outage is necessary for the performance of work associated with SEEG and induced draft fan duct expansion joint replacement. Work such as SEEG can potentially be avoided if the Company's proposal to retire Campbell Unit 3 in 2025 is approved in its 2021 IRP, Case No. U-21090.

Miscellaneous Outages

Q. Are other outages projected for 2022?

A. Yes. In addition to the major outages which I have just discussed, there are other planned outages scheduled for various generating plants whose planned durations are less than 28 days. These outages are scheduled to remove screens from valves after turbine inspections, to remove zebra mussels from raw water piping, and to perform work on other equipment that will not operate for extended periods without attention. To the extent possible, all of 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 (2016 through 2020) and are modified to reflect current operating conditions and recent investments. This is shown in Exhibit A-12 (NJK-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 2022 ROR for Karn Unit 3 is projected to be 15.21% lower than the five-year average. 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 offline due to the sharing of a common duct) and COVID in 2020.

Karn Unit 4

The 2022 ROR for Karn Unit 4 is projected to be 19.48% lower than the five-year average. 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, in part, due to failure of the Karn Unit 4 induced draft fan 4B in 2020.

Ludington Unit 5

The 2022 ROR for Ludington Unit 5 is projected to be 12.61% lower than the five-year average. The subsequent overhaul and upgrade in 2016 and early 2017 significantly improved the projected ROR.

<u>Availability</u>

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

A. Yes. The 2022 projected availability for each of the generating units is shown in Exhibit A-12 (NJK-2), column (b).

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

Q. Does Consumers Energy expect to incur expenses in 2022 related to the Oxides of Nitrogen (“NO_x”) emission allowance program?

A. No.

Q. Please explain why Consumers Energy does not expect to incur expenses in 2022 related to the NO_x emission allowance program.

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. 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”) through the use of 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 Circuit Court for the District of Columbia ("DC Circuit Court"), but in a second ruling in December 2008, the DC Circuit Court reinstated the regulation and remanded it back to the Environmental Protection Agency ("EPA") to be revised. In August 2011, the EPA finalized the CAIR replacement rule, known as the Cross-State Air Pollution Rule ("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 United States Court of Appeals for the District of Columbia ("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 Circuit Court for additional litigation proceedings. On October 23, 2014, the DC Circuit Court ordered that the stay of CSAPR be lifted and that Phase I should be in effect as of 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.

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 2022 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 2022 related to the SO_2 emission allowance program.

A. The Company has installed Flue Gas Desulfurization ("FGD") equipment in the form of Spray Dry Absorbers ("SDAs") at its Karn site, and 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 Environmental Quality which pushed compliance to April 16, 2016. Consumers Energy has five coal-fired units and two oil-fired units subject to MATS.

Urea Expenses

Q. Are there urea expenses for which Consumers Energy is seeking recovery in 2022?

A. Yes. Exhibit A-13 (NJK-3) identifies the projected urea expenses through 2025.

Q. Please describe Exhibit A-13 (NJK-3).

A. In 2022, Consumers Energy projects spending $2.7 million for urea as a necessary expense of operating Campbell Units 2 and 3. In 2023, Consumers Energy expects to spend $2.8 million for urea. For the years 2024 through 2026, urea expenses are expected to be $2.8, $0.9, and $0 million, respectively.

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 2021 PSCR Plan case U-20802 projections?

A. The projected expense for urea has increased for the years 2022 through 2024 and dropped in 2025. The projected increase in urea expense is primarily a direct result of an increase in the urea unit cost as a result of commodity price increases. Increases in natural gas pricing have led to increased urea unit price increases and projected urea expense. The projected urea unit costs for Campbell Units 2 and 3 have increased by approximately 32% and 43% respectively versus those reflected in the 2021 PSCR Plan case U-20802.

The decrease in urea expense in 2025 and beyond is a result of the Company's proposed retirement of Campbell Units 2 and 3 on May 31, 2025, as reflected in its June 30, 2021 IRP, Case No. U-21090.

Q. Has the Commission 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. I recommend the same treatment in 2022.

<u>Aqueous Ammonia Expenses</u>

Q. Are there Aqueous Ammonia expenses for which you are seeking recovery in 2022?

A. Yes. Exhibit A-14 (NJK-4) identifies the projected aqueous ammonia expenses for the years 2022 through 2026.

Q. Please describe Exhibit A-14 (NJK-4).

A. In 2022, Consumers Energy projects spending $0.9 million for aqueous ammonia as a necessary expense of operating Karn Units 1 and 2 and Zeeland Unit 2 (the Combined Cycle unit). In 2023, Consumers Energy also expects to spend $0.4 million for aqueous ammonia associated with the operation of those units. For each of the years 2024 through 2026, expenses are expected to be $0.2 million, respectively.

Q. Why does the projected expense for Aqueous Ammonia begin to decrease in 2023?

A. 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 through 2023 Midcontinent Independent System Operator, Inc. Planning Year. As a result of the Karn Units 1 and 2 retirements, Zeeland will be the sole user of Aqueous Ammonia – see Exhibit A-14 (NJK-4).

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. In 2012, the Company replaced the urea system at Karn Units 1 and 2 with a NO_x control system that uses aqueous ammonia. This new system was designed to be more reliable and effective at reducing NO_x emissions.

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. I recommend the same treatment in 2022.

<u>Lime Expenses</u>

Q. Are there lime expenses for which you are seeking recovery in 2022?

A. Yes. Exhibit A-15 (NJK-5) identifies the projected lime expenses for the years from 2022 through 2026.

Q. Please describe Exhibit A-15 (NJK-5).

A. In 2022, Consumers Energy projects spending \$8.0 million for lime. In 2023, Consumers Energy expects to spend \$7.3 million for lime. In the years from 2024 through 2026, lime expenses are expected to be \$6.7, \$2.3, and \$0 million, respectively.

Q. How will lime be used?

A. The Company has installed FGD units (a.k.a. SDA and DSI) at its Karn and Campbell sites. SDAs were installed at Karn Units 1 and 2 in 2014 and were installed at Campbell Unit 3 in early 2016; these units consume 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. I recommend the same treatment in 2022.

Q. How does the projected lime expense compare to the Company's 2021 PSCR Plan case U-20802 projections?

A. The projected expense for lime reflects an overall increase for the years 2022 through 2024 before dropping in 2025. The 2022, 2023, and 2024 projected lime expense projected in the Company's 2021 PSCR Plan case U-20802 was $6.9, $5.8, and $5.9 milllion respectively versus current projections of $8.0, $7.3, and $6.7 million respectively. The majority of this projected cost increase is attributable to lime expense Campbell Units 2 and 3 due to the consumption of higher sulfur coal at Campbell Units 2 and 3 as well as increased increased commodity pricing for pebble lime.

The decrease in lime expense in 2025 and beyond is a result of the Company's proposed retirement of Campbell Units 1 through 3 on May 31, 2025, as reflected in its June 30, 2021 IRP, Case No. U-21090.

Activated Carbon Expenses

Q. Are there Activated Carbon expenses for which you are seeking recovery in 2022?

A. Yes. Exhibit A-16 (NJK-6) identifies the projected activated carbon expenses for the years from 2022 through 2026.

Q. Please describe Exhibit A-16 (NJK-6).

A. In 2022, Consumers Energy projects spending $1.0 million for activated carbon as a necessary expense of operating Campbell Units 1 through 3 and Karn Units 1 and 2. In 2023, Consumers Energy expects to spend $0.9 million for activated carbon. In the years from 2024 through 2026, activated carbon expenses are forecasted to be $0.9, $0.3, and $0 million, respectively.

Q. How will activated carbon be used?

A. Activated carbon will be used at both the Karn and Campbell sites. 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. I recommend the same treatment in 2022.

Q. How does the projected activated carbon expense compare to the Company's 2021 PSCR Plan, Case No. U-20802 projections?

A. The projected expense for activated carbon remains relatively flat for the years 2022 through 2024 before dropping in 2025. The decrease in activated carbon expense in 2025 and beyond is a result of the Company's proposed retirement of Campbell Units 1 through 3 on May 31, 2025, as reflected in its June 30, 2021 IRP, Case No. U-21090.

Q. Do the Company's projections of chemical reagent expense reflect the results of prior efforts aimed at reducing PSCR expense?

A. Yes. During 2019 the Company initiated a Commodity Chemicals Request for Proposal ("RFP") aimed at reducing chemical reagent expense. The RFP included Aqueous Ammonia, Granular Urea, Hydrated Lime, Pebble Lime, and Powdered Activated Carbon. During 2019 the Company tested a total of seven products at the Campbell and Karn generation sites, including four non-incumbent products, to determine their viability. The testing included three hydrated lime products, one of which was not an incumbent, three powdered activated carbon products, two of which were not incumbent, and one granulated urea product which was not an incumbent. Based upon the qualification testing and other RFP considerations, new hydrated lime and granulated urea products were selected for use at the Campbell site and an existing powdered activated carbon product was chosen for use at the Campbell and Karn sites. Specification restraints for pebble lime limited the supplier base, thereby limiting consideration to the incumbent product for continuing supply to Campbell Unit 3 and Karn Units 1 and 2. Nonetheless, the new contract did result in a modest cost reductions. The RFP results for aqueous ammonia products, which are a commodity similar to pebble lime and granulated urea, confirmed that the Company already had in place the most competitive arrangements that are available. While the savings achieved by the RFP are still reflected in the cost projections, increases in commodity pricing for urea and pebble lime as well as the consumption of higher sulfur coal at Campell Unit 3 have, in part, offset the Company's cost reduction efforts.

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 cost recovery plan for the 12 months ending December 31, 2022	))))))	Case No. U-21048

EXHIBITS

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-11 (NJK-1)
Page: 1 of 1
Witness: NJKapala
Date: September 2021

Major Outages in the 2022 PSCR Plan

	(a)	(b)	(c)	(d)
Line No.	**Unit**	**Days in 2022**	**Start Date**	**End Date**
1	**Campbell 3**	46	3/28/2022	5/13/2022
2	**Karn 3**	45	9/23/2022	11/7/2022
3	**Karn 4**	45	9/23/2022	11/7/2022
4	**Campbell 2**	42	9/29/2022	11/10/2022

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-12 (NJK-2)

Witness: NJKapala
Date: September 2021

2022 PSCR Random Outage Rate Projections

	(a)	(b)	(c)	(d)	(e)
Line No.	**Unit**	**Availability**	**Periodic Factor**	**2022 Projected ROR**	**Actual ROR 2016-2020**
1	**Campbell 1**	79.18%	6.30%	15.50%	15.43%
2	**Campbell 2**	67.45%	21.11%	14.50%	18.14%
3	**Campbell 3**	83.01%	12.62%	5.00%	7.79%
4	**Karn 1**	67.17%	14.97%	21.00%	21.52%
5	**Karn 2**	79.16%	5.76%	16.00%	14.75%
6	**Karn 3**	73.17%	12.37%	16.50%	31.71%
7	**Karn 4**	73.18%	12.36%	16.50%	35.98%
8	**Ludington 1**	87.96%	9.43%	2.88%	1.92%
9	**Ludington 2**	87.88%	9.51%	2.88%	8.90%
10	**Ludington 3**	88.06%	9.33%	2.88%	2.21%
11	**Ludington 4**	87.87%	9.52%	2.88%	4.35%
12	**Ludington 5**	86.53%	10.90%	2.88%	15.49%
13	**Ludington 6**	87.91%	9.48%	2.88%	5.29%
14	**Hydros**	88.45%	6.90%	5.00%	6.39%
15	**Zeeland CC**	89.42%	6.85%	4.00%	2.43%
16	**Zeeland 1A**	93.77%	2.32%	4.00%	1.95%
17	**Zeeland 1B**	93.78%	2.31%	4.00%	3.18%
18	**Jackson 1**	92.24%	3.41%	4.50%	3.74%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-13 (NJK-3)

Witness: NJKapala
Date: September 2021

2022-2026 Urea Expense

Line No.	(a) Unit	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026
1	**Campbell 2**	$491,706	$505,063	$470,091	$150,617	$0
2	**Campbell 3**	$2,219,593	$2,295,964	$2,358,810	$717,713	$0
3	**Total**	$2,711,298	$2,801,027	$2,828,900	$868,330	$0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-14 (NJK-4)

Witness: NJKapala
Date: September 2021

2022-2026 Aqueous Ammonia Expense

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Unit**	**2022**	**2023**	**2024**	**2025**	**2026**
1	**Karn 1**	$520,308	$228,764	$0	$0	$0
2	**Karn 2**	$203,841	$54,700	$0	$0	$0
3	**Zeeland**	$167,913	$155,827	$186,265	$193,205	$172,205
4	**Total**	$892,062	$439,290	$186,265	$193,205	$172,205

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-15 (NJK-5)
Page: 1 of 1
Witness: NJKapala
Date: September 2021

2022-2026 Lime Expense

Line No.	(a) Unit	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026
1	**Karn 1**	$618,478	$271,926	$0	$0	$0
2	**Karn 2**	$629,465	$168,914	$0	$0	$0
3	**Campbell 1**	$1,610,561	$1,540,828	$1,470,202	$694,967	$0
4	**Campbell 2**	$2,187,428	$2,246,850	$2,091,270	$670,043	$0
5	**Campbell 3**	$2,930,432	$3,031,262	$3,114,235	$947,566	$0
6	**Total**	$7,976,364	$7,259,781	$6,675,707	$2,312,575	$0

2022-2026 Activated Carbon Expense

Line No.	(a) Unit	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026
1	**Karn 1**	$60,564	$26,628	$0	$0	$0
2	**Karn 2**	$64,252	$17,242	$0	$0	$0
3	**Campbell 1**	$395,247	$378,134	$360,801	$170,551	$0
4	**Campbell 2**	$168,049	$172,614	$160,661	$51,476	$0
5	**Campbell 3**	$321,551	$332,615	$341,720	$103,975	$0
6	**Total**	$1,009,663	$927,233	$863,182	$326,002	$0

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	)	Case No. U-21048
supply cost recovery plan for the	)	
12 months ending December 31, 2022	)	
______________________________________	)	

DIRECT TESTIMONY

OF

KEVIN C. LOTT, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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 the Fuels Transportation & Planning Director in the Electric Grid Integration Department.

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 the Electric Grid Integration organization as the Railcar Fleet Manager in the Fossil Fuel Supply group. I have since been promoted to Fuels Transportation & Planning Director.

Q. What are your duties as the Fuels Transportation & Planning Director?

A. My duties include:

- the preparation of short- and long-term projections specifying 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 Karn 3 & 4; and natural gas for Zeeland, Jackson, and Karn 3 & 4 Plants; and

- preparing testimony and filings for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you presented testimony in any Commission cases?

A. Yes. I provided direct and rebuttal 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.

<u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. 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.

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-17 (KCL-1) – Projected As-Burned Coal Costs – 2022;

Exhibit A-18 (KCL-2) – Projected As-Burned Coal Costs (2023 – 2026);

Exhibit A-19 (KCL-3) – Projected As-Burned Oil & Gas Costs – 2022; and

Exhibit A-20 (KCL-4) – Projected As-Burned Oil & Gas Costs (2023 – 2026).

AS-BURNED COAL COSTS

Q. Please explain Exhibit A-17 (KCL-1).

A. Exhibit A-17 (KCL-1) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the year 2022. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and state air emission fees.

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 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 freeze protection treatments to ensure all lading can be removed from the railcars during winter months and to ensure compliance with railroad operating rules and tariffs; the application of any necessary dust inhibitors to ensure compliance with railroad operating rules and tariffs; applicable harbor maintenance fees; 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 either directly to generating plants or to lake terminal facilities, where the coal is transferred to lake vessels for delivery. During 2022, the Company expects to have in effect two contracts that will provide for the shipment of coal on railroads and one contract that will provide vessel services and terminal services for shipments.

COAL TRANSPORTATION RATE DETERMINATION

Q. What process was used to determine freight rates?

A. Freight rates were determined by contract pricing. 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 2022?

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 support that production) for each generating unit. In addition to fuel price, the model uses a variety of inputs, but those most closely related to fuel volume determination include fuel mix, coal quality, and generating unit efficiency. Using the MMBtu coal burn requirements determined from the model, along with inventory considerations, the monthly purchase volumes 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 2022 and do you expect to purchase more?

A. The Company presently has approximately 4.0 million tons of coal committed for 2022 from the multiyear or annual purchases shown in Company witness Rissman's Exhibit A-22 (AKR-1). Currently the Company anticipates purchasing 0.9 million tons of additional coal in 2021 for 2022 delivery.

SPOT COAL PURCHASES

Q. How much coal do you expect to purchase on a spot basis during 2022?

A. Approximately 2.1 million tons of coal are expected to be purchased on a spot basis in 2022.

2023 – 2026 PROJECTED AS-BURNED COAL COSTS

Q. Please explain Exhibit A-18 (KCL-2).

A. Exhibit A-18 (KCL-2) summarizes the projected as-burned coal costs and tonnage at each of the Company's coal-fired generating plants for the years 2023 – 2026. The total cost includes primary fuel, auxiliary fuel, freeze protection and dust inhibiting treatments, and state air emission fees.

Q. How were the projected as-burned coal costs for the years 2023 – 2026 determined?

A. In a manner similar to 2022, with adjustments made to existing supply and transportation contract prices based on the forecasted performance of the indices to which a given contract's pricing is tied, as necessary per the terms of the individual contracts. The fixed prices from those contracts with fixed price components were included without escalation. Forecasted commodity prices provided by Company witness Rissman and transportation costs, as described above, were utilized for open position (unsecured) tonnage.

Q. Are any new contracts anticipated for the 2023 – 2026 time period?

A. Yes. It is anticipated that the Company will be entering into new supply and transportation contracts to replace those contracts which will expire during 2023 – 2026. The pricing for any new coal supply is provided by Company witness Rissman and modeled accordingly. The pricing for any future transportation contracts is modeled in the same manner as existing contracts.

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 plant, the Zeeland plant, and the Jackson plant. In addition, I am supplying the gas fuel cost projections for the New Covert Generating Facility, Dearborn Industrial Generation, the Livingston Generating Station, and the Kalamazoo River Generating Station gas-fired generating units, which are proposed to be acquired by the Company during this 2023 – 2026 forecast period as part of the Proposed Course of Action ("PCA") in the Company's Integrated Resource Plan ("IRP") that was recently filed in MPSC Case No. U-21090.

Q. Please explain Exhibit A-19 (KCL-3).

A. Exhibit A-19 (KCL-3) summarizes the projected as-burned fuel costs and volumes for the Company's oil-fired and natural gas-fired generating plants for the year 2022.

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

A. Company witness Stephen J. Nadeau provided these fuel price projections.

Q. Have you developed as-burned oil and natural gas cost projections for the years 2023 – 2026?

A. Yes, these annual cost projections are shown in Exhibit A-20 (KCL-4).

Q. How were your oil and natural gas projections determined for the years 2023 – 2026?

A. The methods used to determine these projected as-burned costs are the same as those used to determine the projected as-burned costs for 2022.

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 cost recovery plan for the 12 months ending December 31, 2022	))))))	Case No. U-21048

EXHIBITS

OF

KEVIN C. LOTT, PE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-17 (KCL-1)
Page: 1 of 1
Witness: KCLott
Date: September 2021

Projected As-Burned Coal Costs - 2022

Line	**(a)** Plant	**(b)** Burn Volume (Tons)	**(c)** Burn Dollars
1	JHCampbell 1-2	2,009,583	$ 81,527,509
2	JHCampbell 3 (CE Owned)	3,081,685	$ 123,722,480
3	DEKarn 1-2	1,698,817	$ 70,305,856
4	Total	6,790,086	$ 275,555,845

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-18 (KCL-2)
Page: 1 of 1
Witness: KCLott
Date: September 2021

Projected As-Burned Coal Costs
2023 - 2026

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (Tons)					
	Plant		2023	2024	2025	2026
1	JHCampbell 1-2		1,956,641	1,823,355	700,047	0
2	JHCampbell 3 (CE Owned)		3,134,341	3,154,189	946,964	0
3	DEKarn 1-2		581,903	0	0	0
4		Total Burn Tonnage	5,672,884	4,977,544	1,647,011	0
	Burn Dollars					
	Plant		2023	2024	2025	2026
5	JHCampbell 1-2		$ 79,735,328	$ 75,911,636	$ 29,979,638	$ -
6	JHCampbell 3 (CE Owned)		$ 126,930,078	$ 131,029,990	$ 40,401,200	$ -
7	DEKarn 1-2		$ 23,830,222	$ -	$ -	$ -
8		Total Primary Fuel	$ 230,495,627	$ 206,941,626	$ 70,380,838	$ -
9		Total Primary Fuel	$ 230,495,627	$ 206,941,626	$ 70,380,838	$ -
10		Total Auxilliary Fuel	$ 2,932,563	$ 2,333,619	$ 986,926	$ -
11		Total Freeze/Dust Treatme	$ 894,314	$ 786,211	$ 260,074	$ -
12		State Air Emission Fees	$ 356,299	$ 356,299	$ 356,299	$ 300,736
13		Total Coal Burn Cost	$ 234,678,803	$ 210,417,755	$ 71,984,137	$ 300,736

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-19 (KCL-3)

Witness: KCLott
Date: September 2021

Projected As-Burned Oil & Gas Costs - 2022

Line	(a) Plant	(b) Burn Volume	(c) Burn Dollars
1	Zeeland Generating Station	35,715,503	$ 138,933,326
2	Jackson Plant	21,997,676	$ 89,910,999
3	DEKarn 3-4 - Oil	0	$ -
4	DEKarn 3-4 - Gas	521,753	$ 8,626,859
5	Proposed Gas Plant Acquisitions	0	$ -
6	Total		$ 237,471,184

Projected As-Burned Oil & Gas Costs
2023 - 2026

Line	(a)	(b)	(c)	(d)	(e)	(f)
	Burn Volume (BBLS/MCF)					
	Plant		2023	2024	2025	2026
1	Zeeland Generating Station		36,540,615	40,277,354	42,800,769	38,544,211
2	Jackson Plant		21,625,908	21,261,238	21,594,006	20,485,590
3	DEKarn 3-4 - Oil		0	0	0	0
4	DEKarn 3-4 - Gas		0	0	0	0
5	Proposed Gas Plant Acquisitions		12,449,567	22,184,447	29,315,870	35,890,820
	Burn Dollars					
	Plant		2023	2024	2025	2026
7	Zeeland Generating Station		$ 116,700,358	$ 117,792,702	$ 124,364,583	$ 113,801,550
8	Jackson Plant		$ 72,817,216	$ 66,331,496	$ 66,745,024	$ 64,481,713
9	DEKarn 3-4 - Oil		$ -	$ -	$ -	$ -
10	DEKarn 3-4 - Gas		$ 5,470,999	$ -	$ -	$ -
11	Proposed Gas Plant Acquisitions		$ 37,892,097	$ 64,803,345	$ 87,755,504	$ 110,203,874
		Total Primary Fuel	$ 232,880,671	$ 248,927,544	$ 278,865,110	$ 288,487,136
12		Total Primary Fuel	$ 232,880,671	$ 248,927,544	$ 278,865,110	$ 288,487,136
13		Total Auxilliary Fuel	$ 5,826,084	$ 6,543,551	$ 7,250,456	$ 7,501,308
14		State Air Emission Fees	$ 75,808	$ 75,808	$ 75,808	$ 75,808
15		Total Oil & Gas Burn Cost	$ 238,782,563	$ 255,546,903	$ 286,191,374	$ 296,064,253

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, 2022	))))))	Case No. U-21048

DIRECT TESTIMONY

OF

STEPHEN J. NADEAU

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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

A. My name is Stephen J. Nadeau, 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 Manager of Natural Gas Supply for Generation in Fossil Fuel Supply.

<u>QUALIFICATIONS</u>

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

A. I graduated from Alma College in 2001 with a Bachelor of Science Degree in Biochemistry, and from Spring Arbor University in 2011 with a Master of Business Administration. I began working on contract for Consumers Energy in 2002, and became a Company employee in 2005. I have held several positions in the Laboratory Services and Environmental Strategies Departments, and began working in the Fossil Fuel Supply group in February of 2007.

Q. What are your duties as the Manager of Natural Gas Supply for Generation?

A. My duties include managing the natural gas supply used at the Company's electric generating plants; administering the Fuels Management System that tracks all coal shipments, inventory levels, coal consumption, and accounting information; and the preparation of testimony and filings for presentation before the Michigan Public Service Commission ("MPSC" or the "Commission").

Q. Have you previously testified before the MPSC?

A. Yes. I provided testimony in:

- Case No. U-16432-R (2011 PSCR Reconciliation);

- Case No. U-16890-R (2012 PSCR Reconciliation);
- Case No. U-17095-R (2013 PSCR Reconciliation);
- Case No. U-17317-R (2014 PSCR Reconciliation);
- Case No. U-17678-R (2015 PSCR Reconciliation);
- Case No. U-20068 (2017 PSCR Reconciliation);
- 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); and
- Case No. U-20802 (2021 PSCR Plan).

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. I am sponsoring direct testimony with respect to the Company's oil and natural gas commodity price forecasts and procurement strategy for electric generation.

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

A. Yes, I am sponsoring Confidential Exhibit A-21 (SJN-1), Jackson Lateral Pipeline Natural Gas Transportation Agreement.

PRICE PROJECTIONS

Q. On what were the Company's oil and gas commodity price forecasts based?

A. These forecasts were based on price information assembled by the Corporate Risk Management Department within the Company, and were indicative of the future market prices for oil and gas at the time they were prepared.

Q. What were your underlying assumptions for your price projections for 2022?

A. The price of No. 6 and No. 2 oil was based on crude oil projections provided by the Corporate Risk Management Department and our approximation of the relationship between crude oil and No. 6 and No. 2 oil. The price of gas for D.E. Karn ("Karn") Units 3 and 4 was based on the market gas prices (monthly New York Mercantile Exchange ("NYMEX") Henry Hub), provided by the Corporate Risk Management Department, to which the cost of transportation was added. The prices of gas for the Zeeland and Jackson plants were based on gas market prices (monthly NYMEX Henry Hub) provided by the Corporate Risk Management Department, which were adjusted to the proper gas index and in accordance with the gas management services ("GMS") contract. Also included in the price projections were the demand charges associated with the use of the associated lateral pipelines.

Q. Why did 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 traded 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 citygates used for index pricing.

Q. How did the Company determine its projection for the citygates used for index pricing?

A. The Company has determined historical relationships between the respective citygate 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 citygate price.

<u>OIL AND NATURAL GAS PROCUREMENT</u>

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

A. The Zeeland and Jackson plants burn natural gas. Karn Units 3 and 4 can burn natural gas and No. 6 fuel oil.

Q. Holding the discussion for the Zeeland and Jackson plants until later, what sources were assumed for each of these fuels?

A. The No. 6 oil burned at Karn Units 3 and 4 will be purchased on a spot basis as needed. A portion of the gas for Karn Units 3 and 4 will be purchased on a spot basis, and the remainder under a GMS contract, but with spot pricing terms.

Q. Please explain why much of the oil and natural gas that is purchased for consumption in the generating units is purchased on a spot basis, rather than under contract 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 the lower cost, earlier units to be dispatched and whose production is generally more predictable, the oil and gas peaking units typically have more expensive variable costs and are among the last units to be dispatched. The utilization of these units depends 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 either oil or gas and the situation that may arise should volumes be contracted for, required to be taken, and not consumed. 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 electric generation?

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 its generating units?

A. The Company utilizes the provisions contained in its gas transportation agreements to minimize its natural gas related costs. This includes monitoring gas usage and market prices during the month and competitively bidding purchases to minimize cost and to 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 the 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 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 the Karn 3 and 4 plants for a portion of its needs on a seasonal basis.

ZEELAND, JACKSON, AND KARN PLANTS NATURAL GAS

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 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 facility?

A. Consumers Energy is currently in the process of entering into a new contract with a third party (which was competitively bid) 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 will include purchasing the gas, transporting the gas utilizing primary or secondary firm transportation from its purchase origin to the point of delivery (i.e., 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 will be provided for under this GMS service contract, the Company also has a contract with SEMCO that was assigned to the Company at the time of the Zeeland Plant purchase which provides firm gas transportation from SEMCO's point of interconnection with the ANR pipeline system to the Zeeland Plant. The contract with SEMCO was extended for five years in 2017, covering the period 2018 through 2022, with more favorable contract extension terms than the original contract.

Q. How will the GMS contract work?

A. In addition to procuring the gas commodity and transportation service, the Agent will be 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 will also be responsible for purchasing gas as directed by the Company in both the day-ahead gas market and the intraday market as MISO accepts offers from Zeeland in the MISO energy market. In addition, the Agent will provide services to balance gas nomination against dispatch requests from MISO. The pricing of the GMS contract will be 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 will be an all-inclusive commodity price which includes the price the Agent pays for the physical gas and all 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 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 for transportation of up to 186,000 Mcf of gas per day.

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?

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's 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 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 changes, 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. The natural gas transportation agreement for the Jackson lateral pipeline has been included as Confidential Exhibit A-21 (SJN-1).

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

A. Similar to Zeeland, the Company is currently working on entering into a new competitively bid GMS contract with a third-party agent to manage the gas supply for the Jackson Plant.

Q. Does the Company currently use an Agent to manage supplies to Jackson, Zeeland, and Karn?

A. Yes, the Company has historically found it prudent to utilize an Agent for these services.

Q. When do the current GMS agreements for these plants expire?

A. They expire on October 31, 2021.

Q. What is the Company planning to do for gas supply after October 31, 2021?

A. As previously mentioned, the Company is currently working on entering into new GMS contracts after a competitive bidding process. The Company expects the new contracts to have similar terms and pricing as the existing GMS contracts.

Q. Does the method for managing the gas supplies for the Jackson, Zeeland, and Karn plants using an Agent 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 the methods previously described for the pricing of the gas ensures these facilities are reliable and competitive participants in the MISO energy market.

<u>CHANGES DUE TO THE COMPANY'S 2021 INTEGRATED RESOURCE PLAN</u>

Q. Are there any major changes to the Company's plan for natural gas generation in this Plan case?

A. Yes. As Company witness Joshua W. Hahn explains in his direct testimony in this case, four additional natural gas fired generating plants have been added as Company owned assets consistent with the Proposed Course of Action in the Company's 2021 Integrated Resource Plan: Covert Generating Facility ("Covert") with an ownership date of June 1, 2023, Dearborn Industrial Generation ("DIG"), Kalamazoo River Generation Station ("Kalamazoo River"), and Livingston Generating Station ("Livingston"), with the latter three having an ownership date of June 1, 2025.

Q. How does the Company currently plan to supply natural gas to these facilities?

A. For Covert, the Company currently anticipates utilizing a GMS agreement like it does for the Zeeland Plant. Covert is served off the same ANR pipeline as Zeeland, and because of the similarity in location, nature, and operation between the two plants, the Company believes it will be prudent to utilize a GMS agent for the same reasons the Company has elected to use one for the Zeeland Plant. Both Livingston and DIG are served through the DTE Gas Company distribution system through natural gas transportation tariffs, and therefore the Company currently anticipates managing their natural gas supply in a manner similar to the way it manages gas supply for Karn Units 3 and 4, which utilize the Company's natural gas tariffs. Kalamazoo River is served from the Panhandle Eastern Pipeline through a lateral owned by CMS Energy. The Company currently anticipates utilizing a GMS agent for that facility.

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 cost recovery plan for the	)	Case No. U-21048
12 months ending December 31, 2022	)	
	)	

EXHIBIT

OF

STEPHEN J. NADEAU

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

A-21 (SJN-1)
IS CONFIDENTIAL AND BEING FILED UNDER SEAL WITH THE MPSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for approval to implement a power	)	Case No. U-21048
supply cost recovery plan for the	)	
12 months ending December 31, 2022	)	
______________________________________	)	

DIRECT TESTIMONY

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

Q. Would you 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 Manager of Coal Procurement in Fossil Fuel Supply.

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 Grid Integration organization, and specifically began work in the Fossil Fuel Supply group in November 2013. I was promoted to Manager of Coal Procurement in November 2017.

Q. What are your duties as the Manager of Coal Procurement?

A. My responsibilities include purchasing the coal used at the Company's electric generating plants; negotiating and managing associated contracts; assuring coal 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?

A. Yes. I provided testimony in:

- MPSC Case No. U-20202 - 2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
- MPSC Case No. U-20219 - 2019 PSCR Plan;
- MPSC Case No. U-20068 - 2017 PSCR Reconciliation;
- MPSC Case No. U-18142 - 2017 PSCR Plan,
- MPSC Case No. U-18402 - 2018 PSCR Plan,
- MPSC Case No. U-20220 - 2019 PSCR Reconciliation,
- MPSC Case No. U-20525 - 2020 PSCR Plan,
- MPSC Case No. U-20526 - 2020 PSCR Reconciliation; and
- MPSC Case No. U-20802 - 2021 PSCR Plan.

PURPOSE OF DIRECT TESTIMONY

Q. What is the purpose of your direct testimony?

A. I am sponsoring direct testimony with respect to the Company's coal purchases and coal procurement strategy for electric generation for the 2022-2026 period.

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

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

Exhibit A-22 (AKR-1) Coal Contract & Purchase Data.

COAL PURCHASE STRATEGY

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 an economical manner. Coal from different regions are 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 is 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 our 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 approximately 20% to 25% secured for the third calendar year.

Q. Have there been any changes to your coal purchase strategy for 2022 from the previous PSCR filings?

A. No. The Company is continuing to layer coal purchases in order to maintain a diverse portfolio of contracts.

ENVIRONMENTAL CONSIDERATIONS

Q. Would you briefly explain the air pollution considerations that have 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 our coal-fired units. These limitations as set forth in the consent decree have been incorporated into our 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 western 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 a 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 June 16, 2016 for D.E. Karn and December 21, 2017 for J.H. 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 delivery for the 2022-2026 period.

The contracts provide western coal supply to our coal plants. Column (a) lists the suppliers, which for the purpose of this exhibit are represented by contract number. Column (b) identifies the coal type, that is, whether it is eastern coal (originating typically in the Central Appalachian regions of Kentucky and West Virginia) or western coal (originating typically in the Powder River Basin region in Wyoming and Montana). 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 we presently expect to nominate. Column (g) defines the contract price ($/ton).

Q. Could you briefly explain "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 the 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 2022?

A. Yes. We anticipate soliciting for additional coal before the end of 2021 for delivery in 2022.

Q. Do you anticipate entering into any additional coal supply contracts from which tonnage would be received in the 2023-2026 time period?

A. Yes. It is anticipated that the Company will be entering into new coal contracts to provide a secure supply of coal following the Company's coal procurement strategy previously discussed. The need to provide a secure supply of coal beyond 2025 may change if the Company's 2021 Integrated Resource Plan, Case U-21090 is approved.

COAL PRICE DETERMINATION 2022 - 2026

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 prices for coal assumed in this filing are included in the table below:

YEAR	WESTERN ($/Ton)	EASTERN ($/Ton)
2022	$12.49	$60.38
2023	$12.50	$58.85
2024	$12.68	$60.89
2025	$12.94	$63.11
2026	$13.32	$65.00

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 cost recovery plan for the 12 months ending December 31, 2022	))))))	Case No. U-21048

EXHIBIT

OF

ANGELA K. RISSMAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21048
Exhibit No.: A-22 (AKR-1)

Witness: AKRissman
Date: September 2021

2022 - 2026 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	354	Western	12/3/2020	1/1/2022	12/31/2022	1,318,200	$11.85	
2	355	Western	12/15/2020	1/1/2022	12/31/2022	1,318,200	$11.90	
3	359	Western	5/7/2021	1/1/2020	12/31/2021	240,956	$13.05	
4	363	Western	N/A	1/1/2022	12/31/2023	1,131,000	$11.65	*
5		2022 UNCOMMITTED AS OF 2022 PSCR PLAN CASE				3,035,405		
6					**2022 Total**	**7,043,761**		
7	363	Western	N/A	1/1/2022	12/31/2023	1,131,000	$11.90	*
8		2023 UNCOMMITTED AS OF 2022 PSCR PLAN CASE				4,591,589		
9					**2023 Total**	**5,722,589**		

* = NOT FULLY EXECUTED AT DATE OF PLAN FILING

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, 2022	))))))	Case No. U-21048

DIRECT TESTIMONY

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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; and

Case No. U-20802 – 2021 PSCR Plan Case.

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

A. The purpose of my testimony is to present the calculation of the 2022 PSCR Factor.

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

A. Yes, I am sponsoring the following exhibit:

Exhibit A-23 (AGV-1) Calculation of 2022 PSCR Factor.

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

A. Yes.

Q. Please describe Exhibit A-23 (AGV-1).

A. Exhibit A-23 (AGV-1) shows the calculation of the 2022 PSCR Factor. The 2022 PSCR Factor is calculated by dividing line 1, Total Power Supply Cost less Long Term Industrial Load Retention Rate ("LTILRR") Payments provided by Company witness Joshua W. Hahn, by Total System Requirements less LTILRR (measured in units of kilowatt hours ("kWh")) on line 2, provided by Company witness Eugene M. Breuring, to determine the average cost per kWh of requirements on line 3. From this quotient is subtracted the Base Recovery Factor (shown on line 4) collected through the standard tariffs as approved by the Commission. This remaining expense per kWh amount of $0.00163, set forth on line 5, is multiplied by the Line and Transformation Loss Factor on line 6 to determine the 2022 per kWh PSCR Factor of $0.00177 at sales, shown on line 7.

Q. Please explain page 2 of Exhibit A-23 (AGV-1).

A. In March 2021, the Company filed a request for rate relief with the Commission, Case No. U-20963. Included in that filing was a request to modify the Line and Transformation Loss Factor specified in the Company's tariff Rule C8; PSCR Clause. Case No. U-20963 is expected to be decided by the Commission in December 2021. Page 2 of Exhibit A-23 (AGV-1) includes the Company's proposed Line and Transformation Loss Factor from Case No. U-20963 on line 6 of the calculation for the maximum allowable PSCR factor. Once the final order in Case No. U-20963 has been issued, the Company proposes to utilize the approved line loss factor in the calculation of the 2022 PSCR factor.

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. And 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- and under-recovery for the PSCR Plan year. Any amounts over collected are subject to refund with interest at the Company's authorized return on equity, which is currently 9.90%.

Q. In its April 8, 2021 Order in Case No. U-20525, in connection with the transportation services agreement related to the Jackson Plant, the Commission indicated that it was interested in seeing "the manner in which the transactions are handled between the divisions." How does the Company treat the payments made under the agreement in the Company's gas rate cases?

A. Payments received are recorded as transportation revenue in the Company's gas rate cases. Since the asset was paid for by the gas utility, the Company's gas customers receive the benefit through reduced revenue requirement in gas rate cases.

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 cost recovery plan for the 12 months ending December 31, 2022	))))))	Case No. U-21048

EXHIBIT

OF

ANDREW G. VOLANSKY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

Consumers Energy Company

Calculation of 2022 PSCR Factor

Line			
1	Total Power Supply Costs less LTILRR Payments[1]	$	1,897,897,420
2	Total System Requirements less LTILRR in kWh[2]		33,099,039,000
	Jurisdictional Factor Calculation		
3	Average Cost at Requirements (Line 1 / Line 2)	$	0.05733
4	Less: Base Recovery Factor[3]	$	0.05570
5	Remaining Cost per kWh (Line 3 - Line 4)	$	0.00163
6	Line & Transformation Loss Factor[4]		1.08378
7	2022 PSCR Factor at Sales (Line 5 x Line 6)	$	0.00177

Sources: [1]Exhibit A-7 (JWH-1), Page 1, Line 42
[2]WP-EMB-1
[3]Per Order in Case No. U-18322/ Rule C-8, Section B(1) of Company Tariffs
[4]Per Rule C-8 of the Company Tariffs

Consumers Energy Company

Calculation of 2022 PSCR Factor

Line			
1	Total Power Supply Costs less LTILRR Payments[1]	$	1,897,897,420
2	Total System Requirements less LTILRR in kWh[2]		33,099,039,000
	Jurisdictional Factor Calculation		
3	Average Cost at Requirements (Line 1 / Line 2)	$	0.05733
4	Less: Base Recovery Factor[3]	$	0.05570
5	Remaining Cost per kWh (Line 3 - Line 4)	$	0.00163
6	Line & Transformation Loss Factor[4]		1.07735
7	2022 PSCR Factor at Sales (Line 5 x Line 6)	$	0.00176

Sources: [1]Exhibit A-7 (JWH-1), Page 1, Line 42
[2]WP-EMB-1
[3]Per Order in Case No. U-18322/ Rule C-8, Section B(1) of Company Tariffs
[4]Per Rule C-8 of the Company Tariffs

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	)	Case No. U-21048
12 months ending December 31, 2022	)	
____________________________________	)	

DIRECT TESTIMONY

OF

EMILY M. WALAINIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

Q. Please state your name and business address.

A. My name is Emily M. Walainis, 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 Contract Strategies in the Contracts and Settlements Section of the of the Electric Grid Integration Department.

QUALIFICATIONS

Q. Please describe your educational background and business experience.

A. I received a bachelor's degree in finance from Michigan State University and a Master of Business Administration degree from the University of Michigan.

Prior to joining Consumers Energy, I worked as an investment banking analyst at Wells Fargo from 2008 to 2011. In this role, I built comprehensive financial models, completed due diligence and credit analysis, and developed offering memoranda and investor presentations to support the origination and execution of syndicated leveraged loans and high yield bonds. From 2011 to 2015, I worked as a financial analyst at Atlas Energy L.P., an oil and gas exploration and production company. In this position, I was the liaison between the decentralized corporate accounting team and operational groups and performed quantitative and qualitative analysis for financial, operational, and combined projects. I joined Consumers Energy in 2016 as a senior financial analyst in the Enterprise Risk department. In this role, I facilitated the enterprise risk management program, which consisted of working with risk owners across corporate and operational groups, to identify, analyze, and present risks to senior management. From 2017 to 2021, I was a senior associate in the Corporate Strategy department where I was responsible for managing the gas, electric, and retail businesses and supporting organizations strategy development. I also worked on the electric vehicle strategy and supported electric vehicle pilot program testimony and exhibits to ensure electric vehicles are successfully integrated into the electric grid for the benefit of all customers.

I started in my current role at Consumers Energy as the Manager of Supply Contracts in the Electric Grid Integration Contract and Settlements department in 2021. I am responsible for implementing the Company's Clean Energy Plan including: 1) the development of annual competitive solicitations for the procurement of wholesale electric generation; 2) negotiations and development of power purchase agreements; and 3) implementation and compliance with the Public Utility Regulatory Policies Act of 1978 (“PURPA”). I am also responsible for managing the: 1) Renewable Energy Plan (“RE Plan”); 2) Experimental Advanced Renewable Program; 3) Renewable Energy Credit administration and compliance; and 4) procurement of supply for the Company's Voluntary Green Pricing (“VGP”) Programs.

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-21009 (direct), the Company’s the Company’s 2020 Renewable Energy Cost Reconciliation case, regarding the actual and expected expenses incurred to implement the Company’s approved Renewable Energy Plan in 2020, the billed surcharge revenues, and a discussion on the Company’s Regulatory Liability Balance projection; and

- Case No. U-21131 (direct), the Company's petition for approval of criteria for the formation of a Legally Enforceable Obligation under the Public Utility Regulatory Policies Act of 1978.

<u>PURPOSE OF DIRECT TESTIMONY</u>

Q. What is the purpose of your direct testimony?

A. My direct testimony will address: (i) the Power Purchase Agreement ("PPA") resources included in this Power Supply Cost Recovery ("PSCR") Plan that have not been previously approved by the Commission; (ii) the treatment of forward commodity sales contracts associated with the Company's 2021 IRP gas plant acquisitions; (iii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iv) the Company's Blackstart Resource Agreement; (v) PSCR treatment of Midcontinent Independent System Operator, Inc. ("MISO") revenue and expenses; and (vi) 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. Yes. I am sponsoring the following exhibit:

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

<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; and
- New Solar Facilities.

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 will terminate during the time period from 2022 to 2026, 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 and Case No. U-20165, as applicable.

On September 11, 2019, the Commission approved the Company's settlement agreement with PURPA QF developers in MPSC Case No. U-20615. The settlement agreement is resulted in the execution of 414 MW of new PPAs with PURPA QFs at the reduced avoided cost rates established in MPSC Case No. U-18090. The settlement also allowed for the substitution of these 414 MW of projects by developers. Presently, 30 MW of the 414 MW are waiting to be reassigned to QF projects by developers.

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

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, the Commission's Order in MPSC Case No. U-20165 approved the settlement agreement in the Company's Integrated Resources Plan ("IRP"). The IRP includes 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 this settlement agreement, 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 rates included in the recently executed PPA with Calhoun Solar Energy LLC. Therefore, the Company has forecast expenses for the new IRP solar PPAs at the Calhoun Solar Energy LLC rates, 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 agreement in MPSC Case No. U-20165. The Company utilizes an Independent Administrator to conduct the solicitation, complete the proposal evaluations, and provide a blind ranking of projects 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-10 (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 2021 PSCR Plan?

A. Yes. The contracts that were not previously included in the 2021 PSCR Plan are listed in Exhibit A-24 (EMW-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 several PPAs since the filing of the 2021 PSCR Plan. These amendments are also shown in Exhibit A-24 (EMW-1) beginning on row (a).

<u>2021 IRP</u>

Q. The Company's 2021 IRP (Case No. U-21090) includes the acquisition of several natural gas facilities and associated forward commodity sales contracts. Please explain how the sales contracts associated with these acquisitions are reflected in this filing.

A. As detailed in the direct testimony of Company witness Keith G. Troyer in Case No. U-21090, the acquisition of the natural gas plants as a result of the 2021 Natural Gas Plant Request for Proposal includes the assignment of existing forward commodity sales contracts associated with those plants. These commodities include capacity, energy, and steam. The Dearborn Industrial Generation ("DIG") Plant currently has a steam contract with the industrial customers located on the same site as the DIG Plant. Furthermore, the plants included in the CMS Enterprises' bid proposal have committed energy and capacity for sales agreements with third parties.

Q. In acquiring these facilities, will the Company assume these contract agreements?

A. Yes. As further explained in Case No. U-21090, the acquisition of the gas plants will result in an obligation for Consumers Energy to honor those contractual commitments, and the revenues from those sales will be used to offset the Company's costs, for the benefit of the Company's customers.

Q. How does the Company intend to recognize the revenue from the forward commodity sales contracts in future regulatory filings?

A. For the forward capacity sales contracts that the Company will assume, the Company intends to treat the revenue received from those contracts as it would treat typical capacity sales revenue received by the Company from the MISO capacity market. With respect to MISO capacity sales, the Company would recognize the revenue received through the sale of capacity in the MISO market through the PSCR mechanism. Therefore, the Company intends to use the same methodology and recognize the capacity revenue of any forward capacity sales contracts through its PSCR mechanism. Similarly, for the forward energy sales contracts that the Company would assume, the Company will treat the revenue received from those contracts as it would treat typical energy sales revenue received by the Company from the MISO energy market. With respect to MISO energy sales, the Company would recognize the revenue received through the sale of energy in the MISO market through the PSCR mechanism. Therefore, the Company intends to also recognize the energy revenue of any forward energy sales contracts through its PSCR mechanism.

With respect to the steam contract, the Company intends to reduce the PSCR recoverable expense by the amount of fuel used to produce the steam sold. The sales revenue for steam and associated fuel cost for steam sales is expected to be recovered through the Company's base rates in an electric rate case proceeding.

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 2022?

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 revenue related to Black Start is discussed in the direct testimony of Company witness Daniel S. Alfred.

TERMINATION OF COMMISSION-APPROVED PPAS

Q. Does the Company have any PPAs, previously approved by the Commission, that have terminated or will terminate in 2022?

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 2022:

- The Company exercised its election to terminate the PPA with STS Hydropower, LLC for the output of the Morrow Hydro Plant effective December 31, 2021;
- The Agreement with Boyce Hydro Power, LLC for the output of the Edenville, Sanford, Smallwood, and Secord hydroelectric facilities will terminate on May 30, 2022;

- The Agreement with Entergy Nuclear Power Marketing, LLC for the output of the Palisades Nuclear Plant will terminate on May 31, 2022;
- The Agreement with Hillman Power Company, LLC for the output of the Hillman Generating Plant will terminate on May 31, 2022; and
- The Agreement with STS Hydropower, LLC for the output of the Ada Hydro Plant will terminate on May 31, 2022.

Q. Does the Company's election to terminate any of these agreements mean that the Company is unwilling to continue buying energy or capacity from eligible PURPA QFs?

A. No. The Company's termination of the aforementioned contracts only means that the Company is exercising its contractual right to terminate the existing terms of those Agreements. The Company anticipates negotiating new contracts which are based on the Company's avoided costs, in accordance with the Commission's orders in Case No. U-18090, Case No. U-20165, and the Commission's determinations in any subsequent cases which set the Company's avoided costs, with eligible PURPA QFs that have an installed capacity up to the Company's PURPA must purchase obligation.

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

A. Prior to September 2021, under PURPA, as well as the Federal Energy Regulatory Commission ("FERC") Orders implementing PURPA, the Company was obligated to buy the energy and capacity through PURPA contracts with QFs up to 20 MW in size. On July 16, 2020, the FERC issued Order 872 which changed the rebuttable presumption that QFs with a capacity greater than 5 MW have market access.

On June 14, 2021, the Company filed an application to terminate the requirement to enter new contracts or obligations to purchase electric energy and capacity from QFs with a net capacity in excess of 5 MW located within the MISO market.

On September 10, 2021 FERC granted the Company's application to terminate its requirement[2]. The order has an effective date of June 14, 2021, the date of the Company's application.

Q. What implication does the FERC order have for this case?

A. The order does not modify the Company's existing PURPA contracts. However, the order does remove QFs from the forecast for new contracts once an existing PPA expires.

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 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 7, 2019 Order in Case No. U-20165 approved the Company's IRP settlement agreement, which maintains that current existing QFs with a 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.[3] 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.

[2] Note that the Company's must-purchase obligation for renewables is 5 MW, but the co-generation must-purchase obligation remains at 20 MW.

MISO ENERGY MARKETS

Q. With regard to serving Consumers Energy's bundled load, will all of 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 2022?

A. Yes. All of 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 2022 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 2022 PSCR Reconciliation case. In this filing, MISO revenues and expenditures are forecast and presented in the direct testimony and exhibits of Company witnesses Alfred and Joshua W. Hahn.

RENEWABLE RESOURCE PROGRAM

Q. Are you familiar with the RRP?

A. Yes. 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 contributions from customers or the Renewable Resource Fund. The Renewable

[3] The IRP settlement agreement defines "QF" as "Qualifying Facilities which the Company has a legal obligation to purchase from under PURPA."

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. How are RRP costs treated in this PSCR Plan?

A. In accordance with the Commission's orders in Case No. U-13843, Consumers Energy has adjusted the cost of energy delivered from the RRP generators to the average PSCR cost calculated before considering the energy delivered by the RRP suppliers themselves. This cost will be recovered from the Company's PSCR customers. The remainder of the cost contracted to be paid to RRP suppliers that remains unrecovered after such adjustment 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*. In this way, the inclusion of the costs associated with these contracts will have no effect on the PSCR factor in accordance with the Commission's May 18, 2004 Order in that case.

<u>RE PLAN</u>

Q. Are you familiar with the Company's RE Plan?

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

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

A. As discussed in Case No. U-18231, 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 to determine the amount of expense to be recovered through the PSCR. The transfer price schedule assigned to a resource remains with that resource through its duration. 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. For PPA resources, the amount of expense recovered through the PSCR is limited on an annual basis to the lesser of: (i) the value of energy, capacity, and ancillary services; and (ii) the actual amount paid to the supplier.

<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) the treatment of forward commodity sales contracts associated with the Company's 2021 IRP gas plant acquisitions; (iii) applicable changes to PPA resources included in this PSCR Plan that have previously been approved by the Commission; (iv) the Company's Blackstart Resource Agreement; (v) PSCR treatment of MISO revenue and expenses; and (vi) 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.

STATE OF MICHIGAN

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, 2022	))))))	Case No. U-21048

EXHIBIT

OF

EMILY M. WALAINIS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

September 2021

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

Case No.: U-21048
Exhibit No.: A-24 (EMW-1)
Page: 1 of 1
Witness: EMWalainis
Date: September 2021

line	(a) Counterparty	(b) New PPA/Amendment	(c) Fuel	(d) MPSC Case No.	(e) MPSC Approval Date
1	**NextSun Energy LLC (Lake City)**	Amendment	Solar PV	U-20604	10/29/2020
2	**NextSun Energy LLC (Morey Road)**	Amendment	Solar PV	U-20604	10/29/2020
3	**NextSun Energy LLC (Surrey Road)**	Amendment	Solar PV	U-20604	10/29/2020
4	**EDL Byron Center, LLC**	New PPA	Landfill Gas	U-20838	2/4/2021
5	**EDL Coopersville, LLC**	New PPA	Landfill Gas	U-20838	2/4/2021
6	**EDL Grand Blanc, LLC**	New PPA	Landfill Gas	U-20838	2/4/2021
7	**EDL Pinconning, LLC**	New PPA	Landfill Gas	U-20838	2/4/2021
8	**Michigan Wind 1, LLC**	Amended & Restated PPA	Wind	U-20942	2/4/2021
9	**Good Fruit Storage, LLC**	New PPA	Solar PV	U-20604	2/18/2021
10	**Midland Cogeneration Venture Limited Partnership**	Amendment	Natural Gas	U-20896	3/4/2021
11	**Calhoun Solar Energy, LLC**	New PPA	Solar PV	U-20165	4/8/2021
12	**TART Solar, LLC**	Amendment	Solar PV	U-20604	6/23/2021
13	**Bay Windpower I (Mackinaw City)**	New PPA	Wind	U-20604	9/9/2021
14	**Heathland Solar, LLC**	New PPA	Solar PV	U-20165	9/9/2021

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, 2022	))))))	Case No. U-21048

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, 2021, she served an electronic copy of the redacted version of **Consumers Energy Company's Application and the Testimony and Exhibits of Consumers Energy Company Witnesses Daniel S. Alfred, Eugène M.J.A. Breuring, Joshua W. Hahn, Norman J. Kapala, Kevin C. Lott, Stephen J. Nadeau, Angela K. Rissman, Andrew G. Volansky, and Emily M. Walainis** 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, 2021.

Jennifer Joy Yocum

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

ATTACHMENT 1 TO CASE NO. U-21048
(Parties to Case Nos. U-20802 and U-20963)

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