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October 11, 2021

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

**RE: Case No. U-21090 – In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.**

Dear Ms. Felice:

Included in this electronic file in the above-captioned case are the **Revised Testimony of Company witness Norman J. Kapala and Exhibits A-50 (NJK-1), A-51 (NJK-2), A-55 (NJK-6), and A-57 (NJK-8), and the Revised Testimony of Company witness Keith G. Troyer**.

The Company is revising the direct testimony of Company witness Keith G. Troyer due to the Commission's July 2, 2021 Order in Case No. U-20905 *et al.* which ordered that Consumers Energy file proposed Public Utility Regulatory Policies Act of 1978 Legally Enforceable Obligation ("LEO") Criteria in a new docket by September 1, 2021. Pursuant to the Commission's direction, the Company filed its proposed LEO criteria in Case No. U-21131. Since LEO criteria is being addressed in Case No. U-21131, the Company is no longer proposing LEO criteria in this matter.

The Company is revising the direct testimony and Exhibits of Company witness Norman J. Kapala due to an inadvertent error in the calculation of certain avoidable Generation costs. The Company is revising Mr. Kapala's direct testimony and exhibits to reflect the corrected avoidable costs.

This is a paperless filing and is therefore being filed only in a PDF format. I have also enclosed a Proof of Service showing electronic service upon the parties.

Sincerely,

RWB

Digitally signed by Robert W. Beach
Date: 2021.10.11 16:57:41 -04'00'

Robert W. Beach

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<br>**CONSUMERS ENERGY COMPANY**<br>for Approval of an Integrated Resource Plan<br>under MCL 460.6t, certain accounting<br>approvals, and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21090 |

# REVISED DIRECT TESTIMONY

# OF

# NORMAN J. KAPALA

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

October 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. What is your formal education experience?**

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

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

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

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

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

| | |
|---|---|
| Case No. U-20165 | 2018 Integrated Resource Plan under MCL 460.6t; |
| Case No. U-20202 | 2018 Power Supply Cost Recovery ("PSCR") Reconciliation; |
| Case No. U-20219 | 2019 PSCR Plan; |
| Case No. U-20220 | 2019 PSCR Reconciliation; |
| Case No. U-20525 | 2020 PSCR Plan; |
| Case No. U-20844 | Ludington Depreciation Case; |
| Case No. U-20802 | 2021 PSCR Plan; and |
| Case No. U-20526 | 2020 PSCR Reconciliation. |

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

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation

activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

**Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?**

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

**Q. Are there any offsets to the avoided cost numbers?**

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

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

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-50 (NJK-1) Revised | Summary of Capital Expenditures and Operations and Maintenance Expenses; |
| Exhibit A-51 (NJK-2) Revised | Summary of Projected Generation Operations Capital Expenditures; |
| Exhibit A-52 (NJK-3) | Summary of Projected Generation Operations Major Maintenance Expenses; |
| Exhibit A-53 (NJK-4) | Summary of Projected Generation Operations Base O&M Expenses; |
| Exhibit A-54 (NJK-5) | Generation Operations – Summary of Capital Expenditures and Costs of Removal; |

| | |
|---|---|
| Exhibit A-55 (NJK-6) Revised | Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants; |
| Exhibit A-56 (NJK-7) | Summary of Projected Generation Operations Separation Activity Capital Expenditures; |
| Exhibit A-57 (NJK-8) Revised | Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032; |
| Exhibit A-58 (NJK-9) | Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032; |
| Exhibit A-59 (NJK-10) | Generating Unit Random Outage Rates; and |
| Confidential Exhibit A-60 (NJK-11) | Generating Unit Heat Rates. |

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

A. Yes.

## SECTION I: EXISTING GENERATION RESOURCES

**Q. Please provide an overview of the Company's non-renewable energy generation assets.**

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

**TABLE 1**

| RESOURCE | MICHIGAN LOCATION | IN-SERVICE DATE | AGE (years) | RETIREMENT DATE | REMAINING EST. TIME OF OPERATION (years) | LICENSING STATUS | NET GENERATING CAPABILITY (MW) |
|---|---|---|---|---|---|---|---|
| **COAL FIRED** | | | | | | | |
| JH Campbell 1 | West Olive, MI | 1962 | 59 | 2031 | 10 | Active | 260 |
| JH Campbell 2 | West Olive, MI | 1967 | 54 | 2031 | 10 | Active | 260 |
| JH Campbell 3 | West Olive, MI | 1980 | 41 | 2039 | 18 | Active | 785 (owned share) |
| DE Karn 1 | Essexville, MI | 1959 | 62 | 2023 | 2 | Active | 255 |
| DE Karn 2 | Essexville, MI | 1961 | 60 | 2023 | 2 | Active | 258 |
| **OIL OR GAS FIRED** | | | | | | | |
| DE Karn 3 | Essexville, MI | 1975 | 46 | 2031 | 10 | Active | 362 |
| DE Karn 4 | Essexville, MI | 1977 | 44 | 2031 | 10 | Active | 362 |
| Zeeland CC | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 575 |
| Zeeland 1A | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 180 |
| Zeeland 1B | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 180 |
| Jackson | Jackson, MI | 2002 | 19 | 2041 | 20 | Active | 547 |
| **HYDROELECTRIC** | | | | | | | |
| Alcona | Alcona County, MI | 1924 | 97 | n/a | n/a | Active | 8 |
| Allegan | Allegan County, MI | 1936 | 85 | n/a | n/a | Active | 3 |
| Cooke | Iosco County, MI | 1911 | 110 | n/a | n/a | Active | 9 |
| Croton | Newaygo County, MI | 1907 | 114 | n/a | n/a | Active | 9 |
| Five Channels | Iosco County, MI | 1912 | 109 | n/a | n/a | Active | 6 |
| Foote | Iosco County, MI | 1918 | 103 | n/a | n/a | Active | 9 |
| Hardy | Newaygo County, MI | 1931 | 90 | n/a | n/a | Active | 30 |
| Hodenpyl | Wexford County, MI | 1925 | 96 | n/a | n/a | Active | 17 |
| Loud | Iosco County, MI | 1913 | 108 | n/a | n/a | Active | 4 |
| Mio | Oscoda County, MI | 1916 | 105 | n/a | n/a | Active | 5 |
| Rogers | Mecosta County, MI | 1906 | 115 | n/a | n/a | Active | 7 |
| Tippy | Manistee County, MI | 1918 | 103 | n/a | n/a | Active | 21 |
| Webber | Ionia County, MI | 1907 | 114 | n/a | n/a | Active | 3 |
| **ENERGY STORAGE** | | | | | | | |
| Ludington Units 1-6 | Ludington, MI | 1973 | 48 | 2069 | 48 | Active | 1138 (owned share) |

**Q. What does "owned share" mean when used with respect to Campbell Unit 3?**

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

**Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?**

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

## SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

**Q. Please explain Exhibit A-50 (NJK-1) Revised.**

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.**

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.**

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.**

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.**

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?**

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?**

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
  - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
  - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
  - Low Pressure Turbine Overhaul ($3,500,000);
  - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
  - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
  - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
  - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
  - Replace CO-O2 Monitors ($1,044,600);
  - Mill Complete Overhauls ($1,235,000);
  - Reheater Sootblower ($1,250,000);
  - Sootblowing Air Upgrade ($1,200,000);
  - Replace Lake Michigan Intake Screens ($1,339,000);
  - Cell Construction and Permitting ($5,482,830); and
  - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?**

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
  - SCR Reactor Catalyst Management ($1,866,200);
  - Complete Mill Overhauls ($1,264,800);
  - Replace CO-O2 Monitors ($967,400);
  - Design and Install New Large Particle Ash Screen ($1,485,100);
  - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?**

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?**

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

- Distributed Control System and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and

- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - SCR Reactor Catalyst Management ($1,959,510);
  - Turbine Drain Modifications ($2,535,000);
  - Superheat Terminal Drain Replacement ($3,023,100);
  - Replace Boiler Sidewall Panels ($2,425,000);
  - Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - Secondary Air Heater basket & seal replacement ($1,562,000);
  - Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~Dry Ash Landfill Closure ($1,635,230);~~
  - Cell Construction and Permitting ($5,482,830); and
  - ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?**

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
  - GSU Replacement ($6,485,045);
  - SCR Reactor Catalyst Management ($3,000,000);
  - AQCS Equipment repair/replacement ($1,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
  - Cell Construction and Permitting ($2,000,000); and
  - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?**

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

- Catalyst Management ($1,120,000); and
- Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~Replace Air and Flue Gas Expansion Joints ($2,000,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?**

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

- Fuel Handling and Infrastructure Replacements ($1,000,000);
- AQCS Equipment repair/replacement ($1,000,000); and
- Two projects totaling $1,500,000 with no individual project which exceeds $500,000;

- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
  - ~~Cell Construction and Permitting ($3,500,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
  - SCR Reactor Catalyst Management ($2,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment repair/replacement ($2,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.**

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation

capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.**

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.**

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.**

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.**

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?**

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?**

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
  - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
  - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
  - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000); and
  - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?**

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?**

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?**

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
  - Campbell 3 Turbine Overhaul ($7,931,350);
  - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
  - Campbell 3 Periodic Outage Maintenance ($933,100); and
  - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?**

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?**

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

**Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?**

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
  - Campbell 3 Turbine Overhaul ($12,000,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
  - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);

- Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
- Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;

- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

**Q. Please explain Exhibit A-52 (NJK-3), page 2.**

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

that the Company would avoid $5,700,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2025.

**Q. Please explain Exhibit A-52 (NJK-3), page 3.**

A. Exhibit A-52 (NJK-3), page 3, shows the Company's projected major maintenance expenses for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-52 (NJK-3), page 3, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 3, line 21, column (c), shows that the Company would avoid $57,555,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 3, line 21, column (f), shows that the Company would avoid $29,984,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-52 (NJK-3), page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

**Q. Please explain Exhibit A-52 (NJK-3), page 4.**

A. Exhibit A-52 (NJK-3), page 4, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 4, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 4,

line 13, columns (d) and (e), show that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 4, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 4, line 26, columns (d) and (e), shows that the Company would avoid $10,696,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 4, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

**Q. Please explain Exhibit A-52 (NJK-3), page 5.**

A. Exhibit A-52 (NJK-3), page 5, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 5,

line 13, columns (d) and (e), shows that the Company would avoid $14,625,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 5, line 13, columns (i) and (j), shows that the Company would avoid $13,385,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 5, line 26, columns (d) and (e), shows that the Company would avoid $12,185,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 5, line 26, columns (i) and (j), show that the Company would avoid $6,427,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

**Q. Please explain Exhibit A-52 (NJK-3), page 6.**

A. Exhibit A-52 (NJK-3), page 6, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 6, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52

(NJK-3), page 6, line 13, columns (d) and (e), shows that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and $14,625,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-52 (NJK-3), page 6, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and $13,385,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-52 (NJK-3), page 6, line 26, columns (d) and (j), shows that the Company would avoid $10,696,000 in major maintenance expenses at Campbell Unit 1 and $12,185,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-52 (NJK-3), page 6, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and $6,427,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 6, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses because the unit separation major maintenance expenses reflected in the base case are not avoided.

**Q. Please explain Exhibit A-53 (NJK-4), page 1.**

A. Exhibit A-53 (NJK-4), page 1, shows the Company's projected base O&M expenses at the Karn and Campbell sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case. In this case, Karn Units 1 and 2 retire May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire May 31, 2031, and Campbell Unit 3 retires May 31, 2039.

**Q. Please explain Exhibit A-53 (NJK-4), page 2.**

A. Exhibit A-53 (NJK-4), page 2, shows the Company's projected base O&M expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-53 (NJK-4), page 2, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 2, column (c), shows that the Company would avoid $92,202,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2023. Exhibit A-53 (NJK-4), page 2, column (f), shows that the Company would avoid $73,220,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2025.

**Q. Please explain Exhibit A-53 (NJK-4), page 3.**

A. Exhibit A-53 (NJK-4), page 3, shows the Company's projected base O&M expenses for the Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), page 3, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 3, column (c) shows that the Company would avoid $432,791,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2025 and Exhibit A-53 (NJK-4), page 3, column (f), shows that the Company would avoid $232,813,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2032.

**Q. Please explain Exhibit A-53 (NJK-4), pages 4 and 5.**

A. Exhibit A-53 (NJK-4), pages 4 and 5, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M

expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 4 and 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 4, line 21, columns (d), (e), and (f) shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $9,334,000 at Campbell Unit 2 and incremental base O&M expenses of $28,524,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 4, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $8,172,000 at Campbell Unit 2 and incremental base O&M expenses of $26,953,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 5, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $6,983,000 at Campbell Unit 2 and incremental base O&M expenses of $25,313,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 5, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $4,531,000 at Campbell Unit 2 and incremental base O&M expenses of $21,990,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2028.

**Q. Please explain Exhibit A-53 (NJK-4), pages 6 and 7.**

A. Exhibit A-53 (NJK-4), pages 6 and 7, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M

expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 6 and 7, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 6, line 21, columns (d), (e), and (f), shows that the Company would avoid $137,616,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,857,000 at Campbell Unit 1 and incremental base O&M expenses of $38,029,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 6, line 21, columns (j), (k), and (l) show that the Company would avoid $136,376,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,626,000 at Campbell Unit 1 and incremental base O&M expenses of $35,919,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 7, line 21, columns (d), (e), and (f) show that the Company would avoid $135,176,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,374,000 at Campbell Unit 1 and incremental base O&M expenses of $33,759,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 7, line 21, columns (j), (k), and (l), shows that the Company would avoid $129,417,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $4,785,000 at Campbell Unit 1 and incremental base O&M expenses of $29,319,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2028.

**Q. Please explain Exhibit A-53 (NJK-4), pages 8 and 9.**

A. Exhibit A-53 (NJK-4), pages 8 and 9, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base

O&M expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 8 and 9, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 8, line 21, columns (d), (e), and (f), shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1, $97,270,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,497,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2024. Exhibit A-53 (NJK-4), page 8, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1, $84,186,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,989,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2025. Exhibit A-53 (NJK-4), page 9, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1, $70,840,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,439,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2026. Exhibit A-53 (NJK-4), page 9, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1, $43,343,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,331,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2028.

**Q. Please explain Exhibit A-54 (NJK-5).**

A. Exhibit A-54 (NJK-5) shows the projected capital expenditures and costs of removal for the Company's remaining generation units. Lines 1 through 5 reflect the total for each year

of capital expenditures and costs of removal. Lines 6 through 10 reflect the total for each year of capital expenditures only.

**Q. Did the Company account for the capital expenditures shown in Exhibit A-54 (NJK-5) in its IRP modeling?**

A. No. The Company's IRP modeling assumed that the generation units listed in Exhibit A-54 (NJK-5) would continue operating until reaching the end of their lifespan when their book values are fully depreciated.

## SECTION III: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF NEW GAS PLANTS

**Q. Please explain Exhibit A-55 (NJK-6) Revised.**

A. Exhibit A-55 (NJK-6) Revised shows the projected capital expenditures and major maintenance expenses for the new gas plants for the period of January 1, 2020 through May 31, 2040. These are the costs and the date range that the Company used for modeling purposes in this IRP.

**Q. Please explain Exhibit A-55 (NJK-6) Revised, page 1.**

A. Exhibit A-55 (NJK-6) Revised, page 1, shows the Company's projected capital expenditures associated with the General Electric Long Term Service Agreement ("LTSA") for DIG and the Mitsubishi LTSA for Covert, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Covert by May 31, 2023 and the acquisition of DIG by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6) Revised, page 1, line 22, column (b), shows that the total projected LTSA capital expenditures for Covert through 2040 are $209,026,000, and Exhibit A-55 (NJK-6)

Revised, page 1, line 22, column (c), shows that the total projected LTSA capital expenditures for DIG are $~~280,091,000~~148,456,000.

**Q. Please explain Exhibit A-55 (NJK-6) Revised, page 2.**

A. Exhibit A-55 (NJK-6) Revised, page 2, shows the Company's projected capital expenditures for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as all projected capital expenditures for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Kalamazoo and Livingston by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6) Revised, page 2, line 22, column (b), shows that the total projected non-LTSA capital expenditures for Covert through 2040 are $114,887,000, and Exhibit A-55 (NJK-6) Revised, page 2, line 22, column (c), shows that the total projected non-LTSA capital expenditures for DIG, Kalamazoo and Livingston are $~~151,696,000~~87,185,000. The projected spike in capital expenditures for non-LTSA capital expenditures in 2027 reflects work to perform rotor replacement at Covert.

**Q. Please explain Exhibit A-55 (NJK-6) Revised, page 3.**

A. Exhibit A-55 (NJK-6) Revised, page ~~1~~3, shows the Company's projected major maintenance expenses for the new natural gas plants associated with the General Electric and Mitsubishi LTSAs for Covert and DIG for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (b), shows that the total projected LTSA major maintenance expenses for Covert through 2040 are $69,829,000, and Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (c), shows that the total projected LTSA major maintenance expenses for DIG are $50,694,000.

**Q. Please explain Exhibit A-55 (NJK-6) Revised, page 4.**

A. Exhibit A-55 (NJK-6) Revised, page 4, shows the Company's projected base O&M expenses for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as the base O&M expenses for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 4, line 22, column (b), shows that the total projected non-LTSA base O&M expenses for Covert through 2040 are $511,184,000, and Exhibit A-55 (NJK-6) Revised, page 4, line 22, column (c), shows that the total projected non-LTSA base O&M expenses for DIG, Kalamazoo, and Livingston are $543,256,000. The non-LTSA base O&M expenses include both fixed and variable O&M expenses.

## SECTION IV: SEPARATION ACTIVITY COSTS

**Q. Please explain Exhibit A-56 (NJK-7).**

A. Exhibit A-56 (NJK-7) shows the separation activity costs that the Company would incur in each retirement case. Exhibit A-56 (NJK-7), lines 1 through 9, shows the separation activity costs as they were modeled by the Company for this IRP, based on assumptions made at the time that the modeling was conducted.

**Q. What are separation activity costs?**

A. Separation activity costs cover those activities that are required to keep the remaining units at a site functioning when other units are retired.

**Q. Are there any separation activity costs in the base case?**

A. Yes. Exhibit A-56 (NJK-7), lines 1 and 2, shows that unit separation costs were modeled in the base case.

**Q. What separation activity costs did the Company model in the event that Karn Units 3 and 4 were retired in 2023?**

A. As shown in Exhibit A-56 (NJK-7), line 3, if Karn Units 3 and 4 are retired in 2023, the Company's IRP modeling assumes a reduction in the separation activity costs at Karn Unit 3 and 4 from $28,651,000 to $13,186,000. These costs could potentially be avoided in 2022 and 2023 once a decision to retire Karn Units 3 and 4 in 2023 is finalized.

**Q. What separation activity costs did the Company model in the event that Campbell Unit 3 operated through May 31, 2039?**

A. As shown in Exhibit A-56 (NJK-7), line 2, if Campbell Unit 3 operates through May 31, 2039, the Company projects that it will incur unit separation costs of $64,146,000. However, as reflected on lines 7 and 9, a Campbell Unit 3 retirement in 2025 or 2032, if coupled with a Campbell Unit 1 and 2 retirement, would allow the Company to entirely avoid the unit separation costs.

**Q. What separation activity cost does the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?**

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur $64,146,000 in separation activity costs at Campbell Unit 3 in the 2024, 2025, 2026, and 2028 Campbell Unit 1 and 2 retirement cases.

**Q. Is the Company requesting Commission approval of the separation activity costs for the Campbell site in this IRP proceeding?**

A. No, the Company is not making such a request in *this* proceeding. The Company developed its projections of $64,146,000 in separation activity costs based on an external conceptual engineering study of the Campbell Unit 1 and 2 unit separation costs. The Company's base

case assumed that this separation work would begin in 2028 in anticipation of a May 31, 2031 retirement date for Campbell Units 1 and 2. The Company believes this estimate is accurate and, as noted above, used this figure when conducting its IRP modeling. To the extent necessary, the Company will develop a more detailed engineering study and construction plans for the separation activity. Those more specific projections for separation activity spending will be presented to the Commission and requested for approval in a future regulatory proceeding.

**Q. What unit separation activity work would be required at the Campbell site?**

A. The following is a high level list of activities that would be performed as part of the Campbell site unit separation:

- Mechanical isolation, cut, & caps, and new electric heating;
- Unit 1 & 2 basement sump modifications and tunnel dewatering;
- Coal pile runoff discharge treatment;
- Unit 1 & 2 communications fed from the Unit 2 switchgear building;
- Unit 2 switchgear building repower - fuel handling and Unit 1 & 2;
- Stackout and reclaim system modifications; and
- Fuel Handling Conveyor reroute/rebuild.

**Q. What separation activity work does the Company plan to avoid if Karn Units 3 and 4 are retired early?**

A. Under a Karn Unit 3 and 4 early retirement case, the Company would avoid capital expenditures in 2022 and 2023. It is impractical to realistically avoid any capital costs in 2021 due to the projected timing of an order in this proceeding.

**Q. What is the Company's schedule for completing this work?**

A. This separation work is currently underway in order to successfully retire Karn Units 1 and 2 on May 31, 2023.

**Q. What are the implications of retiring Karn Units 3 and 4 in 2023 on the unit separation timeline?**

A. Exhibit A-56 (NJK-7), line 3, reflects an extremely aggressive reduction in unit separation capital expenditures for this retirement case in 2022. Due to the potential timing of a final order approving the Company's PCA, it is unrealistic to avoid any unit separation capital expenditures in 2021, and the level of capital expenditures that the Company can avoid in 2022 is entirely dependent on when it receives a decision on its PCA. In order to achieve retirement of Karn Units 1 and 2 on May 31, 2023, the Company must continue to proceed with its current separation of these units from Karn Units 3 and 4.

**Q. What separation activity costs did the Company model in the event that Campbell Units 1 and 2 were retired in 2024, 2025, 2028 or 2031?**

A. Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, shows the costs that the Company's IRP modeling assumes would be incurred at Campbell Unit 3 if both Campbell Units 1 and 2 were retired in 2024, 2025, 2026, 2028. If only one of the two units is retired, the separation activity costs would not be incurred at Campbell Unit 3 until 2028 as modeled in the base case assuming that Campbell Unit 3 operates through 2039. However, if Campbell Unit 3 is retired in 2025 or 2032, and its retirement is coupled with a Campbell Unit 1 and 2 retirement, the unit separation costs can be avoided. The separation activity costs at Campbell Unit 3 in these bases would be an estimated $64,146,000, incurred from 2028 through 2031, to prepare Campbell Unit 3 to operate on a standalone basis once Campbell Units 1 and 2 are retired.

**Q. What separation activity costs would the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?**

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur an estimated $64,146,000 in separation activity costs at Campbell Unit 3 that were projected in the IRP modeling. As previously discussed, these costs can be avoided with an early Campbell Unit 3 retirement case.

**Q. If Campbell Units 1 and 2 were retired, what separation activity work would the Company plan to complete?**

A. In order to allow Campbell Unit 3 to remain operating after the retirement of Campbell Units 1 and 2, the Company would leave the structure housing Campbell Units 1 and 2 in place, with its tripper deck remaining in service. All fuel handling equipment would have to be rerouted and fuel handling, the tripper deck, and ventilation and heating equipment at the site would have to be repowered from Campbell Unit 3. The fuel handling conveyor reroute work constitutes a large portion of the costs reflected in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8. Using this approach would involve fewer upfront costs and would be logistically simpler than building new fuel handling equipment. Leaving the structure housing Campbell Units 1 and 2 standing would require the Company to incur some incremental major maintenance expenses, as discussed later in my direct testimony. Because the structure would remain standing, Campbell Units 1 and 2 would not formally enter the cold and dark period, and it would likely be difficult to pursue any redevelopment opportunities at the site.

## SECTION V: UNAVOIDABLE, AVOIDABLE, AND INCREMENTAL COSTS

**Q. Please explain Exhibit A-57 (NJK-8) Revised.**

A. Exhibit A-57 (NJK-8) Revised illustrates the Company's unavoidable, avoidable, and incremental capital expenditures for each of the early retirement cases.

**Q. What are unavoidable capital expenditures?**

A. Unavoidable capital expenditures represent capital expenditures that the Company must make even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

**Q. Please provide an example of an unavoidable capital expenditure.**

A. The Company's overall plans for capital expenditures were discussed above; the unavoidable capital expenditures are those that the Company must make in any case to ensure safety and reliability. One example of an unavoidable capital expenditure is the Campbell Unit 1 PJFF bag replacement. PJFF bags are part of the AQCS equipment which was installed to comply with Environmental Protection Agency requirements. These PJFF bags remove dry fly ash from the gas exiting the boiler and need to be replaced every four or five years to avoid failure due to plugging. Maintaining the integrity of the bags and being able to properly operate the bag cleaning system are necessary for plant operation within regulatory limits. Multiple bag failures could cause the unit to exceed opacity, resulting in unit derate or forced outage based upon the consent decree. Performance of this work will provide continued environmental compliance. This work is generally

performed on a seven-year cycle, is due to be completed in 2023, and would be required to be completed in the 2025 through 2028 Campbell Unit 1 retirement cases.

**Q. What are avoidable capital expenditures?**

A. Avoidable capital expenditures represent capital expenditures that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego making in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. The avoidable capital expenditures were discussed above in my discussion of Exhibit A-51 (NJK-2) Revised.

**Q. What are incremental costs?**

A. Incremental capital expenditures represent capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in the Company's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made.

**Q. Please explain the incremental capital expenditures shown in Exhibit A-57 (NJK-8) Revised.**

A. The incremental capital expenditures for each retirement case include the expenditures at Campbell Unit 1 in the cases in which Campbell Unit 2 is retired, and incremental capital expenditures at Campbell Unit 2 in the cases in which Campbell Unit 1 is retired. These costs are reflected in Exhibit A-57 (NJK-8) Revised, page 2, lines 4 and 8, for the 2024 retirement case. In Exhibit A-51 (NJK-2) Revised: (i) page 4, line 13, column (e), shows that if Campbell Unit 1 is retired in 2024, the Company will have $253,000 in incremental

capital expenditures at Campbell Unit 2; and (ii) page 5, line 13, column (d), shows that if Campbell Unit 2 is retired in 2024, the Company will have $322,000 in incremental capital expenditures at Campbell Unit 1. These costs represent shifting of fuel handling and infrastructure from the retired unit to the remaining unit for each of these two cases.

**Q. Please explain Exhibit A-58 (NJK-9).**

A. Exhibit A-58 (NJK-9) illustrates the Company's unavoidable, avoidable, and incremental major maintenance expenses for each of the early retirement cases.

**Q. What are unavoidable expenses?**

A. Unavoidable expenses represent major maintenance expenses that the Company must incur even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

**Q. Please provide an example of an unavoidable expense.**

A. Consumers Energy's overall plans for expenses were discussed above; the unavoidable expenses are those that the Company must incur in any case to ensure safety and reliability. As an example, if Campbell Units 1, 2, or 3 are selected for any of the early retirement cases in in 2024, 2025, 2026, 2028, or 2032, the Company will still have O&M expenses for Mill major maintenance.

**Q. What are avoidable major maintenance expenses?**

A. Avoidable expenses represent major maintenance expenses that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025,

2026, 2028, or 2032 are made. The avoidable expenses were discussed above in my discussion of Exhibit A-52 (NJK-3).

**Q. What are incremental major maintenance expenses?**

A. Incremental major maintenance expenses represent O&M expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in Consumers Energy's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. As shown in Exhibit A-58 (NJK-9), pages 1 through 6, the Company has not projected any incremental major maintenance expenses for any of the retirement cases.

## SECTION VI: PERFORMANCE OF EXISTING GENERATION FLEET

**Q. Please explain Exhibit A-59 (NJK-10), page 1.**

A. Exhibit A-59 (NJK-10), page 1, illustrates the historic and projected performance of the Company's coal-fired generating units at the Campbell and Karn sites, measuring their Random Outage Rate ("ROR").

**Q. Please define ROR.**

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

**Q. What factors cause an increase or decrease in ROR?**

A. The frequency and/or duration of a forced or unplanned generating unit outage or generating unit de-rate directly affects ROR. Reducing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates improves ROR.

Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

**Q. How are ROR projections for the generating units developed?**

A. Initial ROR projections are based on five-year historic averages and then adjusted to reflect current operating conditions and projected unit investment. Further than five years into the future, it is increasingly difficult to accurately project ROR, as the number of unknown external factors increase. Therefore, the projected RORs for 2026 through 2031 are based on an assumed slight decrease in performance, accounting for standard corrective capital investments and maintenance.

**Q. Does the ROR measurement reflect customer value?**

A. While a reduced ROR may result in a benefit to customers because of the increased availability of the unit or category of unit, ROR is not itself a measure of customer benefit. The Company utilizes Net Energy Value ("NEV") to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. The historical values are presented in table below.

**TABLE 2**

| | 2016 | 2017 | 2018 | 2019 | 2020 | TOTAL |
|---|---|---|---|---|---|---|
| CAMPBELL 1 | $5,963,929. | $4,201,021. | $8,497,680. | $5,687,739. | $1,468,569. | $25,818,937. |
| CAMPBELL 2 | $6,192,416. | $2,219,726. | $9,133,940. | $4,809,091. | $948,961. | $23,304,133. |
| CAMPBELL 3 | $19,778,737. | $28,200,856. | $47,291,421. | $30,225,507. | $19,665,066. | $145,161,587. |
| | | | | | | |
| KARN 1 | $5,989,670. | $8,176,719. | $7,238,867. | $1,954,120. | $1,362,009. | $24,721,385. |
| KARN 2 | $5,981,023. | $4,466,650. | $6,489,054. | $438,945. | $438,017. | $17,813,688. |

**Q. What can the Company do to positively affect NEV?**

A. Typically, economic investments that improve the reliability and availability of the generating unit or category of unit will result in increasing NEV. Economic investments that result in a reduction in the cost to generate will also result in increasing NEV, all else being equal. Positive NEV increases when a generating unit operates more frequently during periods in which market pricing exceeds the cost of production for that unit. Historically, market pricing has tended to be higher in the summer and winter, although there is variability to market conditions. As discussed earlier in my testimony, this is the reason that periodic outages are generally scheduled in the shoulder months of spring and fall. Market prices are typically lower during this time period, thereby reducing the PSCR impact of each scheduled outage.

**Q. What are the Company's expectations regarding ROR and NEV for its coal-fired generating units?**

A. As presented on Exhibit A-59 (NJK-10), page 1, the Company has projected a steady decline in ROR through retirement for Campbell Units 1 and 2 and Karn Units 1 and 2. As previously discussed, the Company's projections of ROR take into account the projected unit investment and, given the current retirement dates for these units, investments targeted at improving ROR are generally uneconomic and not likely to result in providing incremental customer value. As a result, it is likely that the NEV for these units will also decline slightly as they move closer to retirement.

**Q. Please explain Exhibit A-59 (NJK-10), page 2.**

A. Exhibit A-59 (NJK-10), page 2, illustrates the historic Equivalent Forced Outage Rate Demand ("$EFOR_d$") of the Company's generation units at the Campbell and Karn sites.

**Q. Please define $EFOR_d$.**

A. $EFOR_d$ represents the hours of unit failure (Forced Outage Hours demand + Equivalent Forced Derate Hours demand), given as a percentage of the total hours of unit availability (Service Hours + Forced Outage Hours demand + Equivalent Forced Derate Hours During Reserve Shutdown).

**Q. What does the ROR and $EFOR_d$ information in Exhibit A-59 (NJK-10) indicate about the condition of the existing equipment at Campbell Units 1 and 2 and Karn Units 1 and 2?**

A. Exhibit A-59 (NJK-10) indicates that Campbell Units 1 and 2 have generally performed more reliably than Karn Units 1 and 2 as measured by ROR and $EFOR_d$, and the ROR of Campbell Units 1 and 2 are projected to continue demonstrating better reliability than Karn Units 1 and 2 in future years leading up to retirement. This indicates that the condition of existing equipment at Campbell Units 1 and 2 is generally better than that at Karn Units 1 and 2.

**Q. Are there other measures used to inform operational and financial decisions in order to optimize the customer value of the generating unit?**

A. Investments made to improve reliable operations at generating units can provide capacity value as well as energy value. The Company is required by the Midcontinent Independent System Operation, Inc. ("MISO") to secure enough capacity on an annual basis to cover all of its load, plus a reserve margin. All of the Company's units provide some capacity towards meeting this obligation and $EFOR_d$ is a measure which factors into the determination of that capacity.

**Q. Please explain Confidential Exhibit A-60 (NJK-11), page 1.**

A. Confidential Exhibit A-60 (NJK-11), page 1, illustrates the projected heat rates for Campbell Units 1 and 2 in the base case and the various retirement cases.

**Q. Please define heat rate.**

A. The heat rate or efficiency of a unit is the amount of energy used by an electrical generator to produce one kilowatt-hour (kWh) of electricity, represented in BTU/kWh.

**Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 1 impacted its projected heat rates?**

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 1-12, the heat rate for Campbell Unit 1 through 2023 is identical in the base case and each retirement case. However, in the 2024, 2025, and 2026 Campbell Unit 1 retirement cases, the heat rate degrades (increases) in 2024 due to the elimination of the project to replace the air preheater baskets and seals in 2023 and 2024. As such, only the base case and 2028 retirement case reflect a heat rate improvement in 2024 and beyond. No other projects in the base case provide heat rate improvement.

**Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 2 impacted its projected heat rates?**

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 13-24, the heat rate for Campbell Unit 2 through 2031 is identical in the base case and each retirement case. The reason for this is that there are no major Campbell Unit 2 projects with heat rate effects after the Turbine/Generator work and air heater seal replacement work in 2021. As such, the heat rate degradation is the same for all cases.

## SECTION VII: EXECUTION RISKS OF EARLY RETIREMENT

**Q. What execution risks does the Company face in its plan to retire the Campbell site in 2025?**

A. Since the Company is recommending that the Campbell site be retired early, there are several factors that could make the actual operation of those units until May 31, 2025 difficult. These factors include issues related to plant maintenance and employee retention.

**Q. What are the risks related to plant maintenance?**

A. The Company will continue to make capital investments and incur O&M expenses at Campbell site in order to ensure safe operation. However, as the units get closer to their early retirement date, the Company will have to evaluate any unexpected maintenance issues that may arise to determine if the economics of the situation would justify performing repairs. For example, if one of the units experiences a turbine failure one year prior to the retirement date, the Company would consider both the costs and benefits of replacement and/or repair before proceeding. If replacement and/or repair would result in high costs that could not be recovered before retirement, and replacement energy could be purchased through the MISO market, and replacement capacity could be purchased bilaterally, at a more economic price than the price of replacement and/or repair, then the Company could elect to leave the affected unit in an outage until the retirement date.

**Q. What are the risks related to employee retention?**

A. The Company will develop a thorough plan to ensure that the necessary qualified employees are retained to operate the units through the retirement date, as well as during the cold and dark time period following retirement, as discussed later in my direct testimony. However, once it is certain that the units will retire, employees may begin to

seek positions elsewhere in the Company, or externally. In that circumstance, it could become difficult for the units to be safely operated through the retirement date. When the Company retired the Classic 7 in 2016, and made plans to retire Karn Units 1 and 2 in 2023, the Company was able to mitigate these employee retention risks because it had time to develop a transition plan that gave employees needed confidence to remain at those units through the closure date, knowing that they would likely be able to move to other positions within the Company afterward. However, with the retirement of all remaining coal units, the difficulty of this task has significantly increased. Further, the Company has observed situations involving other utilities in which the retirement of a generation plant was made more difficult by less than adequate human resource management and planning. For example, there have been situations at other utilities in which plant employees were not provided any kind of post-closure transition plan, meaning those employees were liable to lose their jobs, resulting in low morale and delays in the retirement of the plant. By having an effective transition plan in place for employees, the Company can effectively mitigate these risks.

**Q. Is the Company considering environmental risks in retiring the Campbell site?**

A. Yes. When the units are retired, the Company will have to bring the units into compliance with environmental regulations. This will include vacuuming all ash, draining boilers, and removing all oil from the machinery. The Company will ensure that nothing is left at the site that may leak and release pollution into the environment. In performing this environmental work, the Company will ensure that it does not, and will not, exceed any regulatory limits on emissions into local waterways throughout the prolonged cold and dark period, which will require sufficient time during the cold and dark period. If the Company

does not have sufficient time to do this cleaning, it runs the risk of significantly increased clean-up costs in order to ensure that the Company does not violate emissions limits and completes all necessary clean-up work. In addition to the clean-up work itself, the Company will also need to address the coal pile. The Company plans to burn the coal pile down in the final weeks of the units' operation, so that as little coal remains onsite as possible. The Company will evaluate remediation of the land on which the coal pile sits to determine if that land can be redeveloped for other purposes.

**Q. Is the Company considering risks related to the future use of the site?**

A. Yes. The Company has recent experience in evaluating future use of a retired generation unit site, having done so when the Classic 7 were retired and currently doing so for the Karn site. During the Classic 7 retirement process, the Company evaluated various future use options for those sites, and Consumers Energy had enough time in that process to effectively study the divestment of those sites and opportunities to divest to third parties who would also manage facility demolition and redevelopment, mitigating the risk of unnecessarily high costs and optimizing customer value since a specialized firm would manage demolition and redevelopment instead of the Company doing so directly. In the case of Campbell site, the Company would also need time to study different future use options for the site, and to vet different options for both Company-managed demolition and redevelopment and for divestment to a third-party firm to do that work.

**Q. Are there future use risks related to the local community?**

A. Impacts to the community when the Campbell site retires are discussed later in my direct testimony. At a high level, the retirement will impact the community's tax base and employment base. The Company is committed to assisting in redevelopment of the site to

offset these impacts, and to communicating with the community as much as possible to facilitate this.

**Q. If Campbell Units 1 and 2 were retired in 2024 instead of 2025, as the Company considered in other cases, would there be additional risks?**

A. Yes. As noted above, the Company has demonstrated an ability to responsibly and safely retire and decommission a coal-fired generation unit when given sufficient time to develop a transition plan that ensures needed employee retention so that operations can be appropriately wound down in a safe and environmentally responsible manner, which would also allow the Company to assess impacts to the local community and develop a transition plan for that as well. Assuming that this filing receives Commission approval in 2022, a 2024 retirement date does not give the Company adequate time. A 2024 retirement date would not allow the Company enough time to implement a safe and responsible transition plan for environmental clean-up, for employee transitions, or for community transitions.

**Q. Are there any further concerns related to retiring Campbell Units 1 and 2 in 2024 instead of 2025?**

A. Yes. The Company has made significant capital investments in Campbell Units 1 and 2 to ensure their compliance with environmental standards as well as to maintain reliability. Operating Campbell Units 1 and 2 until 2025 increases the benefits of those investments as the units will continue to provide energy and capacity for a longer period of time; conversely, retiring Campbell Units 1 and 2 in 2024 would reduce the time that those capital investments provide benefits to customers.

**Q. Are there any risks that would result in Campbell site being required to be operated beyond 2025?**

A. Yes. To retire a generation unit, the Company must get approval from MISO. MISO will study the Company's retirement proposal to ensure that it does not create transmission reliability concerns, particularly related to maintaining voltage on the transmission system. If MISO finds that transmission reliability concerns will exist, MISO may require one or more of the units to remain in operation until such time that a solution is found and completed to mitigate the reliability problem. As part of its stakeholder process, MISO would consider solutions, such as: (i) re-dispatch or reconfiguration of the transmission system; (ii) special protection schemes; (iii) contracted demand response; (iv) new or expanded generation elsewhere on the system; and (v) transmission expansion.

**Q. What would happen if MISO does require one or both units to remain in operation?**

A. If MISO makes such a determination, it would designate the unit or units as a System Support Resource ("SSR"). When a unit becomes an SSR, MISO ensures that the unit fully recovers its ongoing operating costs by assigning those costs to affected MISO transmission customers through MISO's Federal Energy Regulatory Commission-regulated transmission rates.

## SECTION VIII: TAX, COMMUNITY, AND EMPLOYEE IMPACTS OF EARLY RETIREMENT

### Karn Units 3 and 4

**Q. What is the tax impact of Karn Units 3 and 4?**

A. The Company pays property taxes on Karn Units 3 and 4 that fund local governmental services provided by Hampton Township and Bay County. The units' 2020 taxable value was $25.6 million, which was approximately 0.87% of the total taxable value in Bay

County and 7.6% of the total taxable value in Hampton Township. The units' 2021 taxable value had a small increase of approximately 1%.

**Q. Aside from property tax revenues, what other impacts will the retirement of Karn Units 3 and 4 in 2023 have on its respective community?**

A. Gas-fired generation units provide employment in the communities in which they are located and can be local economic drivers. Retirement of Karn Units 3 and 4 in combination with Karn Units 1 and 2 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

**Q. How will the Company provide that help?**

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company has commissioned a detailed future-use study to analyze specific potential opportunities to redevelop the Karn site.

**Q. Please explain the community transition plan for Karn Units 3 and 4.**

A. The community transition plan for Karn Units 3 and 4 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. This transition will be updated by the Company subsequent to this filing. The transition plan will identify and describe the economic strengths of Bay County and advantages of the Karn site for future redevelopment, which would be explored

in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area and potential threats to redevelopment.

**Q. Please describe the results of the Company's transition planning for retirement of the Classic 7.**

A. The Company's transition plans for the Classic 7 focused on a smooth transition through open communication and regional sustainable vision alignment. The performance of future use studies along with collaboration with community stakeholders were critical to the Classic 7 decommissioning process. The Company's community partners included residents, government officials, state elected officials, economic development organizations, vendors, state agencies, and employees affected by the closure.

**Q. How has the Company's community engagement resulted in success for the affected communities?**

A. The Company's community engagement process at its Cobb plant, which is located at the Port of Muskegon, helped regional community leaders find new solutions to market and manage the port and re-imagine the potential for Muskegon Lake. Current plans include conversion of the area into a deep-water marine terminal. Similarly, the Company's stakeholder engagement process associated with the closing, near-complete demolition and active redevelopment of the Whiting plant will result in a site which is ideal for manufacturing and warehousing based upon its extensive logistical advantages such as rail and direct access to I-75.

**Q. Please explain the community communication plan for Karn Units 3 and 4.**

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Karn Units 3 and 4; this communication is the key first

step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

**Q. Please explain the future-use study process for Karn Units 3 and 4**.

A. The Company has been conducting a future-use study as part of its process for planning to retire Karn Units 1 and 2. These studies will consider environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. The retirement of all four Karn units in 2023 will un-restrain potential redevelopment options for the Karn site which is adjacent to the formerly retired Weadock site. Previous redevelopment options for the Weadock site were limited to reuse by the Company for other purposes. The Company will consider options for private redevelopment, as the retirement of Karn Units 1, 2, 3, & 4 may make more of the site, such as the port facilities, available for redevelopment.

**Q. How will the retirement of Karn Units 3 and 4 in 2023 affect Company employees?**

A. The employees that support the operation of Karn Units 1 and 2 as well as Karn Units 3 and 4 are Karn site employees. As such, all of the employees that directly support day-to-day facility operation were included in the Company's retention and separation program which was established to support the retirement of Karn Units 1 and 2 in 2023. The

Company continues to be committed to ensuring a smooth transition for the Karn employees as the decommissioning process for the Karn site is implemented.

**Campbell Units 1, 2, and 3**

**Q. What is the tax impact of Campbell Units 1, 2, and 3?**

A. The Company pays property taxes on Campbell Units 1, 2, and 3 that fund local governmental services provided by Port Sheldon Township and Ottawa County. The units' 2020 taxable valuation was $143.8 million, which is approximately 1.15% of the total taxable value in Ottawa County and 27% of the total taxable value in Port Sheldon Township. The units' 2021 taxable value declined by 12.5%, due to a decline in market conditions for coal-fired power plants. The overall taxable value of the Campbell site is expected to continue to decline due to negative market conditions facing coal-fired generation.

**Q. Aside from property tax revenues, what other impacts will the retirement of Campbell Units 1, 2, and 3 in 2025 have on its respective community?**

A. Coal-fired generation units provide employment in the communities in which they are located and can be significant local economic drivers. Retirement of Campbell Units 1, 2, and 3 in 2025 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

**Q. How will the Company provide that help?**

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will

be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company plans to complete a detailed future-use study to analyze specific potential opportunities to redevelop the Campbell site.

**Q. Please explain the community transition plan.**

A. The community transition plan for Campbell Units 1, 2, and 3 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. The transition plan will identify and describe the economic strengths of Ottawa County and advantages of the Campbell site for future redevelopment, which would be explored in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area, and potential threats to redevelopment.

**Q. Please explain the community communication plan.**

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Campbell Units 1, 2, and 3; this communication is the key first step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

**Q. Please explain the future-use study process**.

A. The Company previously developed future-use studies as part of its process for retiring the Classic 7 and, as previously mentioned, is in the process of conducting a future use study for the Karn site. These studies considered environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. Because the Company intends to retire the Campbell site in its entirety, the potential redevelopment options are less restrained than if only one or two of the three units were retired.

**Q. How many employees does the Company currently have at the Campbell site?**

A. The Campbell site currently has 405 employees at the Campbell site, 313 of whom directly support day-to-day facility operation, with representatives of the Company's Generation Operations, Generation Engineering, Environmental, and other groups. Within the total number of 313 employees that directly support day-to-day facility operation, 214 employees are operations, maintenance, and construction ("OM&C") employees, 75 are exempt employees, and 24 are non-exempt employees. Employees in executive, manager and supervisor, professional, and outside sales positions are considered by the Company to be *exempt* from the Fair Labor Standards Act's minimum wage, overtime pay, and certain record-keeping requirements, and are considered at-will employees. Employees who work as technicians, office and clerical staff, and administrative support are considered *not to be exempt* from those requirements. OM&C employees at the Campbell site are represented by the Utility Workers Union of America ("UWUA").

**Q. How will the retirement of the Campbell site in 2025 affect Company employees?**

A. The Company is committed to ensuring a smooth transition for employees as the decommissioning process for Campbell is implemented. The Company will use regular and transparent internal communications with its employees to ensure that employees are informed about the Company's plans. The Company will leverage the lessons it learned from its successful experience in retiring the Classic 7 and planning for retirement of Karn Units 1 and 2 in developing a retention and separation plan to govern how employees are treated during the decommissioning process of Campbell Units.

**Q. What is the Company's intended timing for its retention and separation plan?**

A. Once a retirement date for the Campbell site is established, pursuant to an MPSC order in this case, the Company will implement a retention plan that takes effect 40 months prior to that retirement date. For example, if the Campbell Units are scheduled to complete their cold and dark activities by October 31, 2025, then the retention plan would go into effect on July 1, 2022. The retention plan for OM&C employees was previously negotiated with the UWUA and approved by Company leadership; retention plans for other classifications of employees have been developed by the Company, as well. The separation plan exists within current Company agreements and policies and would take effect when the Campbell site retires.

**Q. What is the purpose of the retention component of the Company's plan?**

A. The Company has a strong interest in keeping qualified employees working at the Campbell site through the site's retirement date to ensure safe and reliable operations. Once a retirement date for the Campbell site is confirmed, some employees may seek employment at other Company locations or outside of the Company; meanwhile, hiring

new employees at the Campbell site will become more difficult given the short remaining lifespan of the units, plus the training time necessary for any new hires is challenging. Using the best practices that the Company employed in retiring the Classic 7 and planning for the retirement of Karn Units 1 and 2, the Company plans to offer retention bonuses to all impacted employees who stay at the Campbell site for the entire 40-month period noted above.

**Q. What is the purpose of the separation component of the Company's plan?**

A. When the Campbell site is retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement with the Company within 30 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position; relocation policies for OM&C employees are explained in further detail below.

**Q. What are the estimated costs of the retention and separation plan?**

A. Based on current employment levels and demographics, the Company estimates the costs of this retention program, including estimated severance and moving cost, is $60 million if all employees qualify for the retention bonus and all retirement-eligible employees accept

a severance offer. It is the Company's intent to find placements for as many employees as possible, thus mitigating the cost of separations.

**Q. Is the Company requesting recovery of the retention incentive costs in this proceeding?**

A. Yes. As discussed by Company Witness Jason R. Coker, the Company is requesting the expense recognition to be deferred as a regulatory asset until such time that the expenses are recovered in rates.

**Q. What is the possible impact to affected employees at the Campbell site?**

A. The Company expects that approximately 313 employees will be needed to continue operation of the Campbell site until its proposed retirement in 2025. The rest of the employees will be covered by the policy relevant to their classification. The Working Agreement covering OM&C employees guarantees all eligible OM&C employees a position at their current respective wage within 60 miles of the Campbell site. It is the Company's intent that all exempt and non-exempt employees, who desire to retain employment with the Company, will be offered another position. However, in the event that exempt or non-exempt employees cannot find placement within the Company, they will be offered involuntary severance in accordance with the terms of the Salaried Separation Plan. The Company has 7 locations within 60 miles of the Campbell site.

**Q. What is the Company's recent history with managing employee impacts following the retirement of a coal-fired power plant?**

A. Following the retirement of the Classic 7 in 2016, all Company employees who desired to continue employment with the Company were able to do so. The Company believes that this demonstrates the Company's commitment to its employees. The retirement of the

Classic 7 was successful because all employees had confidence that they would maintain secure employment following plant closure. As described earlier in my direct testimony, maintaining this confidence is essential for mitigating the Company's execution risk in retiring the Campbell site.

**Q. How much time is needed for the Company to execute its plan for employees?**

A. As discussed above, the Company plans for its retention plan to cover a 40-month period, preceded by negotiation and approval. This period of time is particularly necessary because many employees will need to be retrained for new jobs. When the Company retired the Classic 7, many operators were able to move to other coal-fired facilities within the Company, limiting the need for retraining. Since the Company plans to retire all of its remaining coal-fired units, this option is no longer available. Furthermore, the 7 Company locations within 60 miles of the Campbell site consist of numerous service centers, where the work is substantially different than at a generating site. Employees from the Campbell site who move, for example, to the West Kent Service Center may need several months of training to become certified in the distribution maintenance work done at that location. The Company's goal is to facilitate a smooth transition by having employees trained to move into new positions as soon as possible after the retirement of the Campbell site. The Company is capable of managing this transition, having done so with the Classic 7, but it needs sufficient time for workforce planning as well to ensure that appropriate positions are available for employees.

**Q. To minimize retraining, could the Company relocate employees from the Campbell site to the Covert site?**

A. Yes. The Covert site is within 60 miles of the Campbell site. While gas and coal generating plants are operated differently, there are many similarities with respect to maintenance which could allow for a relatively smooth transition for some Campbell employees. To the extent that employees relocate to locations which are not within a 60 mile radius of the Campbell site, the Company's Working Agreement covering OM&C employees allows those employees to receive Company-paid moving expenses if they accept a position more than 60 miles away, and the Company is providing an additional relocation incentive for employees moving more than 60 miles.

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

A. Yes.

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Capital Expenditures and Operations and Maintenance Expenses
January 1, 2020 through May 31, 2031
($000)

Case No.: U-21090
Exhibit No.: A-50 (NJK-1) Revised
Page: 1 of 6
Witness: NJKapala
Date: October 2021

**Generation Operations - Capital Scenarios**

**Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|
| | Karn 1 & 2 Total | Karn 3 & 4 Total | Karn 3 & 4 Separation Total | Campbell 1 Total | Campbell 2 Total | Campbell 3 Total | Campbell 3 Separation Total |
| 1 | $ 13,294 | $ 82,598 | $ 28,651 | $ 57,878 | $ 79,020 | $ 195,597 | $ 64,146 |

**Retire Karn Units 3 & 4 5/31/2023**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case |
|---|---|---|---|
| 2 | $ 6,950 | $ (75,648) | $ (15,465) |

**Retire Karn Units 3 & 4 5/31/2025**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case |
|---|---|---|---|
| 3 | $ 19,611 | $ (62,987) | $ (9,161) |

**Retire Campbell Unit 3 5/31/2025**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case | Campbell Unit 3 Separation Variance to Base Case |
|---|---|---|---|
| 4 | $ 59,291 | $ (136,306) | $ (64,146) |

**Retire Campbell Unit 3 5/31/2032**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case | Campbell Unit 3 Separation Variance to Base Case |
|---|---|---|---|
| 5 | $ 157,697 | $ (37,900) | $ (64,146) |

**Retire Campbell 1 5/31/2024**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 6 | $ 15,037 | $ 79,273 | $ (42,840) | $ 253 |

**Retire Campbell 1 5/31/2025**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 7 | $ 21,926 | $ 79,020 | $ (35,951) | $ - |

**Retire Campbell 1 5/31/2026**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 8 | $ 23,831 | $ 79,020 | $ (34,046) | $ - |

**Retire Campbell 1 5/31/2028**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 9 | $ 43,436 | $ 79,020 | $ (14,442) | $ - |

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).
3. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

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| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|

**Generation Operations - Capital Scenarios**

**Retire Campbell 2 5/31/2024**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 10 | $ 58,200 | $ 22,950 | $ 322 | $ (56,070) |

**Retire Campbell 2 5/31/2025**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 11 | $ 57,878 | $ 32,446 | $ - | $ (46,573) |

**Retire Campbell 2 5/31/2026**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 12 | $ 57,878 | $ 33,746 | $ - | $ (45,273) |

**Retire Campbell 2 5/31/2028**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 13 | $ 57,878 | $ 60,687 | $ - | $ (18,333) |

**Retire Campbell 1&2 5/31/2024**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 14 | $ 15,037 | $ 22,950 | $ (42,840) | $ (56,070) | $ - |

**Retire Campbell 1&2 5/31/2025**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 15 | $ 21,926 | $ 32,446 | $ (35,951) | $ (46,573) | $ - |

**Retire Campbell 1&2 5/31/2026**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 16 | $ 23,831 | $ 33,746 | $ (34,046) | $ (45,273) | $ - |

**Retire Campbell 1&2 5/31/2028**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 17 | $ 43,436 | $ 60,687 | $ (14,442) | $ (18,333) | $ - |

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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**Generation Operations - Major Maintenance Scenarios**

**Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039**

| Line No. | Karn 1 & 2 Total | Karn 3 & 4 Total | Campbell 1 Total | Campbell 2 Total | Campbell 3 Total |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | $ 9,465 | $ 11,050 | $ 29,361 | $ 28,814 | $ 74,700 |

**Retire Karn Units 3 & 4 5/31/2023**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case |
|---|---|---|
| 2 | $ 1,000 | $ (10,050) |

**Retire Karn Units 3 & 4 5/31/2025**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case |
|---|---|---|
| 3 | $ 5,350 | $ (5,700) |

**Retire Campbell Unit 3 5/31/2025**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case |
|---|---|---|
| 4 | $ 17,145 | $ (57,555) |

**Retire Campbell Unit 3 5/31/2032**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case |
|---|---|---|
| 5 | $ 44,716 | $ (29,984) |

**Retire Campbell 1 5/31/2024**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 6 | $ 14,845 | $ 28,814 | $ (14,516) | $ - |

**Retire Campbell 1 5/31/2025**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 7 | $ 17,247 | $ 28,814 | $ (12,114) | $ - |

**Retire Campbell 1 5/31/2026**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 8 | $ 18,666 | $ 28,814 | $ (10,696) | $ - |

**Retire Campbell 1 5/31/2028**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| 9 | $ 23,262 | $ 28,814 | $ (6,100) | $ - |

1. Excludes environmental costs related to SEEG and 316(b).
2. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

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**Generation Operations - Major Maintenance Scenarios**

**Retire Campbell 2 5/31/2024**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 10 | $ 29,361 | $ 14,189 | $ - | $ (14,625) |

**Retire Campbell 2 5/31/2025**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 11 | $ 29,361 | $ 15,428 | $ - | $ (13,385) |

**Retire Campbell 2 5/31/2026**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 12 | $ 29,361 | $ 16,629 | $ - | $ (12,185) |

**Retire Campbell 2 5/31/2028**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 13 | $ 29,361 | $ 22,387 | $ - | $ (6,427) |

**Retire Campbell 1&2 5/31/2024**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 14 | $ 14,845 | $ 14,189 | $ (14,516) | $ (14,625) | $ - |

**Retire Campbell 1&2 5/31/2025**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 15 | $ 17,247 | $ 15,428 | $ (12,114) | $ (13,385) | $ - |

**Retire Campbell 1&2 5/31/2026**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 16 | $ 18,666 | $ 16,629 | $ (10,696) | $ (12,185) | $ - |

**Retire Campbell 1&2 5/31/2028**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 17 | $ 23,262 | $ 22,387 | $ (6,100) | $ (6,427) | $ - |

1. Excludes environmental costs related to SEEG and 316(b).

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| (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|

**Generation Operations - Base O&M Retirement Scenarios**

**Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039**

| Line No. | Karn 1 & 2 Total | Karn 3 & 4 Total | Campbell 1 Total | Campbell 2 Total | Campbell 3 Total |
|---|---|---|---|---|---|
| 1 | $ 86,987 | $ 119,895 | $ 110,877 | $ 151,804 | $ 574,054 |

**Retire Karn Units 3 & 4 5/31/2023**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case |
|---|---|---|
| 2 | $ 27,693 | $ (92,202) |

**Retire Karn Units 3 & 4 5/31/2025**

| | Karn 3 & 4 Total | Karn 3 & 4 Variance to Base Case |
|---|---|---|
| 3 | $ 46,675 | $ (73,220) |

**Retire Campbell Unit 3 5/31/2025**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case |
|---|---|---|
| 4 | $ 141,264 | $ (432,791) |

**Retire Campbell Unit 3 5/31/2032**

| | Campbell Unit 3 Total | Campbell Unit 3 Variance to Base Case |
|---|---|---|
| 5 | $ 341,242 | $ (232,813) |

**Retire Campbell 1 5/31/2024**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 6 | $ 39,791 | $ 151,804 | $ (71,086) | $ 9,334 | $ 28,524 |

**Retire Campbell 1 5/31/2025**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 7 | $ 49,353 | $ 151,804 | $ (61,524) | $ 8,173 | $ 26,953 |

**Retire Campbell 1 5/31/2026**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 8 | $ 59,106 | $ 151,804 | $ (51,771) | $ 6,983 | $ 25,313 |

**Retire Campbell 1 5/31/2028**

| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
|---|---|---|---|---|---|
| 9 | $ 79,202 | $ 151,804 | $ (31,675) | $ 4,531 | $ 21,990 |

1. Excludes environmental costs related to SEEG and 316(b).
2. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

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**Generation Operations - Base O&M Retirement Scenarios**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| | **Retire Campbell 2 5/31/2024** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 10 | $ 110,877 | $ 14,189 | $ 9,857 | $ (137,616) | $ 38,029 |
| | **Retire Campbell 2 5/31/2025** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 11 | $ 110,877 | $ 15,428 | $ 8,626 | $ (136,376) | $ 35,919 |
| | **Retire Campbell 2 5/31/2026** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 12 | $ 110,877 | $ 16,629 | $ 7,375 | $ (135,176) | $ 33,759 |
| | **Retire Campbell 2 5/31/2028** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 13 | $ 110,877 | $ 22,387 | $ 4,785 | $ (129,417) | $ 29,319 |
| | **Retire Campbell 1&2 5/31/2024** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 14 | $ 39,791 | $ 54,534 | $ (71,086) | $ (97,270) | $ 9,497 |
| | **Retire Campbell 1&2 5/31/2025** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 15 | $ 49,353 | $ 67,618 | $ (61,524) | $ (84,186) | $ 8,989 |
| | **Retire Campbell 1&2 5/31/2026** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 16 | $ 59,106 | $ 80,964 | $ (51,771) | $ (70,840) | $ 8,439 |
| | **Retire Campbell 1&2 5/31/2028** | | | | |
| | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Campbell 3 Variance to Base Case |
| 17 | $ 79,202 | $ 108,461 | $ (31,675) | $ (43,343) | $ 7,331 |

1. Excludes environmental costs related to SEEG and 316(b).

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**Generation Operations - Capital - Base Retirement Case**

**Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039**

| Line No. | Year | (a) | Karn 1/2 Total (b) | Karn 3/4 Total (c) | Campbell 1 Total (d) | Campbell 2 Total (e) | Campbell 3 Total (f) |
|---|---|---|---|---|---|---|---|
| 1 | 2020 | | 7,176 | 8,679 | 10,025 | 9,268 | 12,860 |
| 2 | 2021 | | 2,859 | 4,172 | 3,493 | 13,512 | 19,576 |
| 3 | 2022 | | 2,135 | 15,416 | 7,300 | 5,257 | 17,125 |
| 4 | 2023 | | 1,124 | 10,072 | 7,215 | 9,472 | 20,478 |
| 5 | 2024 | | | 9,775 | 9,753 | 11,252 | 33,396 |
| 6 | 2025 | | | 10,134 | 2,550 | 7,800 | 14,512 |
| 7 | 2026 | | | 9,900 | 3,300 | 4,420 | 4,400 |
| 8 | 2027 | | | 8,950 | 4,050 | 6,845 | 5,900 |
| 9 | 2028 | | | 2,000 | 3,500 | 7,394 | 4,400 |
| 10 | 2029 | | | 2,000 | 3,879 | 2,500 | 11,750 |
| 11 | 2030 | | | 1,000 | 2,564 | 1,050 | 11,150 |
| 12 | 2031 | | | 500 | 250 | 250 | 2,400 |
| 13 | 2032 | | | | | | 2,750 |
| 14 | 2033 | | | | | | 11,750 |
| 15 | 2034 | | | | | | 5,400 |
| 16 | 2035 | | | | | | 10,150 |
| 17 | 2036 | | | | | | 4,650 |
| 18 | 2037 | | | | | | 2,400 |
| 19 | 2038 | | | | | | 550 |
| 20 | 2039 | | | | | | |
| 21 | Total | | $ 13,294 | $ 82,598 | $ 57,878 | $ 79,020 | $ 195,597 |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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**Generation Operations - Capital - Karn 3&4 Early Retirement Case**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Karn 3&4 5/31/2023** | | | | | **Retire Karn 3 & 4 5/31/2025** | | | |
| Line No. | Year | Karn 3&4 Total | Karn 1&2 ariance to Base Cas | Karn 3&4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case | Year | Karn 3&4 Total | Karn 1&2 ariance to Base Cas | Karn 3&4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case |
| 1 | 2020 | 5,500 | - | (3,179) | - | 2020 | 8,679 | - | - | - |
| 2 | 2021 | 750 | - | (3,422) | - | 2021 | 6,012 | - | 1,840 | (667) |
| 3 | 2022 | 500 | - | (14,916) | (13,675) | 2022 | 2,370 | - | (13,046) | (7,204) |
| 4 | 2023 | 200 | - | (9,872) | (1,790) | 2023 | 1,850 | - | (8,222) | (1,290) |
| 5 | 2024 | - | - | (9,775) | - | 2024 | 500 | - | (9,275) | - |
| 6 | 2025 | - | - | (10,134) | - | 2025 | 200 | - | (9,934) | - |
| 7 | 2026 | - | - | (9,900) | - | 2026 | - | - | (9,900) | - |
| 8 | 2027 | - | - | (8,950) | - | 2027 | - | - | (8,950) | - |
| 9 | 2028 | - | - | (2,000) | - | 2028 | - | - | (2,000) | - |
| 10 | 2029 | - | - | (2,000) | - | 2029 | - | - | (2,000) | - |
| 11 | 2030 | - | - | (1,000) | - | 2030 | - | - | (1,000) | - |
| 12 | 2031 | - | - | (500) | - | 2031 | - | - | (500) | - |
| 13 | Total | $ 6,950 | $ - | $ (75,648) | $ (15,465) | Total | $ 19,611 | $ - | $ (62,987) | $ (9,161) |

Note:
1. Cost of removal has not been included.

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**Generation Operations - Capital - Campbell 3 Early Retirement Cases**

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|
| | **Retire Campbell 3 5/31/2025** | | | | **Retire Campbell 3 5/31/2032** | | |
| Line No. | Year | Campbell 3 Total | Campbell 3 Variance to Base Case | Campbell Unit 3 Separation Variance to Base Case | Year | Campbell 3 Total | Campbell 3 Variance to Base Case | Campbell Unit 3 Separation Variance to Base Case |
| 1 | 2020 | 12,860 | 0 | - | 2020 | 12,860 | 0 | - |
| 2 | 2021 | 18,397 | (1,179) | - | 2021 | 19,576 | - | - |
| 3 | 2022 | 12,885 | (4,240) | - | 2022 | 17,125 | - | - |
| 4 | 2023 | 8,705 | (11,773) | - | 2023 | 20,478 | - | - |
| 5 | 2024 | 6,044 | (27,352) | - | 2024 | 33,396 | - | - |
| 6 | 2025 | 400 | (14,112) | - | 2025 | 14,512 | - | - |
| 7 | 2026 | - | (4,400) | - | 2026 | 4,400 | - | - |
| 8 | 2027 | - | (5,900) | - | 2027 | 5,900 | - | - |
| 9 | 2028 | - | (4,400) | (6,780) | 2028 | 4,400 | - | (6,780) |
| 10 | 2029 | - | (11,750) | (14,341) | 2029 | 8,750 | (3,000) | (14,341) |
| 11 | 2030 | - | (11,150) | (28,683) | 2030 | 11,150 | - | (28,683) |
| 12 | 2031 | - | (2,400) | (14,341) | 2031 | 2,400 | - | (14,341) |
| 13 | 2032 | - | (2,750) | - | 2032 | 2,750 | - | - |
| 14 | 2033 | - | (11,750) | - | 2033 | - | (11,750) | - |
| 15 | 2034 | - | (5,400) | - | 2034 | - | (5,400) | - |
| 16 | 2035 | - | (10,150) | - | 2035 | - | (10,150) | - |
| 17 | 2036 | - | (4,650) | - | 2036 | - | (4,650) | - |
| 18 | 2037 | - | (2,400) | - | 2037 | - | (2,400) | - |
| 19 | 2038 | - | (550) | - | 2038 | - | (550) | - |
| 20 | 2039 | - | - | - | 2039 | - | - | - |
| 21 | Total | $ 59,291 | $ (136,306) | $ (64,146) | Total | $ 157,697 | $ (37,900) | $ (64,146) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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**Generation Operations - Capital - Campbell 1 Early Retirement Cases**

**Retire Campbell 1 5/31/2024**

| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 1 | 2020 | 9,644 | 9,268 | (381) | - |
| 2 | 2021 | 3,293 | 13,541 | (200) | 29 |
| 3 | 2022 | 1,050 | 5,257 | (6,250) | - |
| 4 | 2023 | 800 | 9,696 | (6,415) | 224 |
| 5 | 2024 | 250 | 11,252 | (9,503) | - |
| 6 | 2025 | - | 7,800 | (2,550) | - |
| 7 | 2026 | - | 4,420 | (3,300) | - |
| 8 | 2027 | - | 6,845 | (4,050) | - |
| 9 | 2028 | - | 7,394 | (3,500) | - |
| 10 | 2029 | - | 2,500 | (3,879) | - |
| 11 | 2030 | - | 1,050 | (2,564) | - |
| 12 | 2031 | - | 250 | (250) | - |
| 13 | Total | $ 15,037 | $ 79,273 | $ (42,840) | $ 253 |

**Retire Campbell 1 5/31/2025**

| Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| | (f) | (g) | (h) | (i) | (j) |
| 2020 | 9,989 | 9,268 | (36) | - |
| 2021 | 3,293 | 13,512 | (200) | - |
| 2022 | 3,810 | 5,257 | (3,490) | - |
| 2023 | 3,784 | 9,472 | (3,431) | - |
| 2024 | 800 | 11,252 | (8,953) | - |
| 2025 | 250 | 7,800 | (2,300) | - |
| 2026 | - | 4,420 | (3,300) | - |
| 2027 | - | 6,845 | (4,050) | - |
| 2028 | - | 7,394 | (3,500) | - |
| 2029 | - | 2,500 | (3,879) | - |
| 2030 | - | 1,050 | (2,564) | - |
| 2031 | - | 250 | (250) | - |
| Total | $ 21,926 | $ 79,020 | $ (35,951) | $ - |

**Retire Campbell 1 5/31/2026**

| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 14 | 2020 | 9,989 | 9,268 | (36) | - |
| 15 | 2021 | 3,293 | 13,512 | (200) | - |
| 16 | 2022 | 3,810 | 5,257 | (3,490) | - |
| 17 | 2023 | 4,073 | 9,472 | (3,141) | - |
| 18 | 2024 | 1,616 | 11,252 | (8,137) | - |
| 19 | 2025 | 800 | 7,800 | (1,750) | - |
| 20 | 2026 | 250 | 4,420 | (3,050) | - |
| 21 | 2027 | - | 6,845 | (4,050) | - |
| 22 | 2028 | - | 7,394 | (3,500) | - |
| 23 | 2029 | - | 2,500 | (3,879) | - |
| 24 | 2030 | - | 1,050 | (2,564) | - |
| 25 | 2031 | - | 250 | (250) | - |
| 26 | Total | $ 23,831 | $ 79,020 | $ (34,046) | $ - |

**Retire Campbell 1 5/31/2028**

| Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| | (f) | (g) | (h) | (i) | (j) |
| 2020 | 10,025 | 9,268 | - | - |
| 2021 | 3,493 | 13,512 | - | - |
| 2022 | 7,300 | 5,257 | - | - |
| 2023 | 7,215 | 9,472 | - | - |
| 2024 | 9,753 | 11,252 | - | - |
| 2025 | 2,550 | 7,800 | - | - |
| 2026 | 2,050 | 4,420 | (1,250) | - |
| 2027 | 800 | 6,845 | (3,250) | - |
| 2028 | 250 | 7,394 | (3,250) | - |
| 2029 | - | 2,500 | (3,879) | - |
| 2030 | - | 1,050 | (2,564) | - |
| 2031 | - | 250 | (250) | - |
| Total | $ 43,436 | $ 79,020 | $ (14,442) | $ - |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

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**Generation Operations - Capital - Campbell 2 Early Retirement Cases**

**Retire Campbell 2 5/31/2024**

| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 1 | 2020 | 10,025 | 8,861 | - | (407) |
| 2 | 2021 | 3,530 | 11,739 | 37 | (1,773) |
| 3 | 2022 | 7,300 | 1,300 | - | (3,957) |
| 4 | 2023 | 7,500 | 800 | 285 | (8,672) |
| 5 | 2024 | 9,753 | 250 | - | (11,002) |
| 6 | 2025 | 2,550 | - | - | (7,800) |
| 7 | 2026 | 3,300 | - | - | (4,420) |
| 8 | 2027 | 4,050 | - | - | (6,845) |
| 9 | 2028 | 3,500 | - | - | (7,394) |
| 10 | 2029 | 3,879 | - | - | (2,500) |
| 11 | 2030 | 2,564 | - | - | (1,050) |
| 12 | 2031 | 250 | - | - | (250) |
| 13 | Total | $ 58,200 | $ 22,950 | $ 322 | $ (56,070) |

**Retire Campbell 2 5/31/2025**

| Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| | (f) | (g) | (h) | (i) | (j) |
| 2020 | 10,025 | 9,219 | - | (49) |
| 2021 | 3,493 | 13,271 | - | (241) |
| 2022 | 7,300 | 5,107 | - | (150) |
| 2023 | 7,215 | 3,800 | - | (5,672) |
| 2024 | 9,753 | 800 | - | (10,452) |
| 2025 | 2,550 | 250 | - | (7,550) |
| 2026 | 3,300 | - | - | (4,420) |
| 2027 | 4,050 | - | - | (6,845) |
| 2028 | 3,500 | - | - | (7,394) |
| 2029 | 3,879 | - | - | (2,500) |
| 2030 | 2,564 | - | - | (1,050) |
| 2031 | 250 | - | - | (250) |
| Total | $ 57,878 | $ 32,446 | $ - | $ (46,573) |

**Retire Campbell 2 5/31/2026**

| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) |
| 14 | 2020 | 10,025 | 9,219 | - | (49) |
| 15 | 2021 | 3,493 | 13,271 | - | (241) |
| 16 | 2022 | 7,300 | 5,107 | - | (150) |
| 17 | 2023 | 7,215 | 3,800 | - | (5,672) |
| 18 | 2024 | 9,753 | 1,300 | - | (9,952) |
| 19 | 2025 | 2,550 | 800 | - | (7,000) |
| 20 | 2026 | 3,300 | 250 | - | (4,170) |
| 21 | 2027 | 4,050 | - | - | (6,845) |
| 22 | 2028 | 3,500 | - | - | (7,394) |
| 23 | 2029 | 3,879 | - | - | (2,500) |
| 24 | 2030 | 2,564 | - | - | (1,050) |
| 25 | 2031 | 250 | - | - | (250) |
| 26 | Total | $ 57,878 | $ 33,746 | $ - | $ (45,273) |

**Retire Campbell 2 5/31/2028**

| Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
|---|---|---|---|---|
| | (f) | (g) | (h) | (i) | (j) |
| 2020 | 10,025 | 9,268 | - | - |
| 2021 | 3,493 | 13,512 | - | - |
| 2022 | 7,300 | 5,257 | - | - |
| 2023 | 7,215 | 9,472 | - | - |
| 2024 | 9,753 | 11,252 | - | - |
| 2025 | 2,550 | 4,800 | - | (3,000) |
| 2026 | 3,300 | 3,170 | - | (1,250) |
| 2027 | 4,050 | 3,706 | - | (3,139) |
| 2028 | 3,500 | 250 | - | (7,144) |
| 2029 | 3,879 | - | - | (2,500) |
| 2030 | 2,564 | - | - | (1,050) |
| 2031 | 250 | - | - | (250) |
| Total | $ 57,878 | $ 60,687 | $ - | $ (18,333) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

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**Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1&2 5/31/2024** | | | | | **Retire Campbell 1&2 5/31/2025** | | | |
| Line | | Campbell 1 | Campbell 2 | Campbell 1 | Campbell 2 | | Campbell 1 | Campbell 2 | Campbell 1 | Campbell 2 |
| No. | Year | Total | Total | Variance to Base Case | Variance to Base Case | Year | Total | Total | Variance to Base Case | Variance to Base Case |
| 1 | 2020 | 9,644 | 8,861 | (381) | (407) | 2020 | 9,989 | 9,219 | (36) | (49) |
| 2 | 2021 | 3,293 | 11,739 | (200) | (1,773) | 2021 | 3,293 | 13,271 | (200) | (241) |
| 3 | 2022 | 1,050 | 1,300 | (6,250) | (3,957) | 2022 | 3,810 | 5,107 | (3,490) | (150) |
| 4 | 2023 | 800 | 800 | (6,415) | (8,672) | 2023 | 3,784 | 3,800 | (3,431) | (5,672) |
| 5 | 2024 | 250 | 250 | (9,503) | (11,002) | 2024 | 800 | 800 | (8,953) | (10,452) |
| 6 | 2025 | - | - | (2,550) | (7,800) | 2025 | 250 | 250 | (2,300) | (7,550) |
| 7 | 2026 | - | - | (3,300) | (4,420) | 2026 | - | - | (3,300) | (4,420) |
| 8 | 2027 | - | - | (4,050) | (6,845) | 2027 | - | - | (4,050) | (6,845) |
| 9 | 2028 | - | - | (3,500) | (7,394) | 2028 | - | - | (3,500) | (7,394) |
| 10 | 2029 | - | - | (3,879) | (2,500) | 2029 | - | - | (3,879) | (2,500) |
| 11 | 2030 | - | - | (2,564) | (1,050) | 2030 | - | - | (2,564) | (1,050) |
| 12 | 2031 | - | - | (250) | (250) | 2031 | - | - | (250) | (250) |
| 13 | Total | $ 15,037 | $ 22,950 | $ (42,840) | $ (56,070) | Total | $ 21,926 | $ 32,446 | $ (35,951) | $ (46,573) |

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1&2 5/31/2026** | | | | | **Retire Campbell 1&2 5/31/2028** | | | |
| Line | | Campbell 1 | Campbell 2 | Campbell 1 | Campbell 2 | | Campbell 1 | Campbell 2 | Campbell 1 | Campbell 2 |
| No. | Year | Total | Total | Variance to Base Case | Variance to Base Case | Year | Total | Total | Variance to Base Case | Variance to Base Case |
| 14 | 2020 | 9,989 | 9,219 | (36) | (49) | 2020 | 10,025 | 9,268 | - | - |
| 15 | 2021 | 3,293 | 13,271 | (200) | (241) | 2021 | 3,493 | 13,512 | - | - |
| 16 | 2022 | 3,810 | 5,107 | (3,490) | (150) | 2022 | 7,300 | 5,257 | - | - |
| 17 | 2023 | 4,073 | 3,800 | (3,141) | (5,672) | 2023 | 7,215 | 9,472 | - | - |
| 18 | 2024 | 1,616 | 1,300 | (8,137) | (9,952) | 2024 | 9,753 | 11,252 | - | - |
| 19 | 2025 | 800 | 800 | (1,750) | (7,000) | 2025 | 2,550 | 4,800 | - | (3,000) |
| 20 | 2026 | 250 | 250 | (3,050) | (4,170) | 2026 | 2,050 | 3,170 | (1,250) | (1,250) |
| 21 | 2027 | - | - | (4,050) | (6,845) | 2027 | 800 | 3,706 | (3,250) | (3,139) |
| 22 | 2028 | - | - | (3,500) | (7,394) | 2028 | 250 | 250 | (3,250) | (7,144) |
| 23 | 2029 | - | - | (3,879) | (2,500) | 2029 | - | - | (3,879) | (2,500) |
| 24 | 2030 | - | - | (2,564) | (1,050) | 2030 | - | - | (2,564) | (1,050) |
| 25 | 2031 | - | - | (250) | (250) | 2031 | - | - | (250) | (250) |
| 26 | Total | $ 23,831 | $ 33,746 | $ (34,046) | $ (45,273) | Total | $ 43,436 | $ 60,687 | $ (14,442) | $ (18,333) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
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**Generation Operations - LTSA Capital**

| Line No. | Year | (a) | (b) Covert Total | (c) DIG Total |
|---|---|---|---|---|
| 1 | 2020 | | - | |
| 2 | 2021 | | - | - |
| 3 | 2022 | | - | - |
| 4 | 2023 | | 7,863 | - |
| 5 | 2024 | | 13,798 | - |
| 6 | 2025 | | 14,117 | 6,668 |
| 7 | 2026 | | 14,446 | 11,696 |
| 8 | 2027 | | 14,790 | 11,975 |
| 9 | 2028 | | 15,143 | 12,261 |
| 10 | 2029 | | 15,499 | 12,549 |
| 11 | 2030 | | 15,855 | 12,838 |
| 12 | 2031 | | 16,212 | 13,127 |
| 13 | 2032 | | 16,575 | 13,421 |
| 14 | 2033 | | 16,948 | 13,723 |
| 15 | 2034 | | 17,323 | 14,026 |
| 16 | 2035 | | 17,702 | 14,333 |
| 17 | 2036 | | 4,522 | 3,954 |
| 18 | 2037 | | 4,623 | 4,042 |
| 19 | 2038 | | 2,836 | 3,061 |
| 20 | 2039 | | 773 | 782 |
| 21 | 2040 | | - | - |
| 22 | Total | $ | 209,026 | $ 148,456 |

Notes:
1. Cost of removal has not been included.

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

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**Generation Operations - non-LTSA Capital**

| Line No. | (a) Year | (b) Covert Total | (c) DIG, Kalamazoo, Livingston Total |
|---|---|---|---|
| 1 | 2020 | - | |
| 2 | 2021 | - | - |
| 3 | 2022 | - | - |
| 4 | 2023 | 3,128 | - |
| 5 | 2024 | 5,488 | - |
| 6 | 2025 | 5,615 | 2,948 |
| 7 | 2026 | 5,746 | 5,171 |
| 8 | 2027 | 12,942 | 5,295 |
| 9 | 2028 | 6,023 | 5,421 |
| 10 | 2029 | 6,165 | 5,548 |
| 11 | 2030 | 6,307 | 5,676 |
| 12 | 2031 | 6,449 | 5,804 |
| 13 | 2032 | 6,593 | 5,934 |
| 14 | 2033 | 6,741 | 6,067 |
| 15 | 2034 | 6,890 | 6,201 |
| 16 | 2035 | 7,041 | 6,337 |
| 17 | 2036 | 7,195 | 6,475 |
| 18 | 2037 | 7,355 | 6,620 |
| 19 | 2038 | 7,520 | 6,768 |
| 20 | 2039 | 7,688 | 6,919 |
| 21 | 2040 | - | - |
| 22 | Total | $ 114,887 | $ 87,185 |

Notes:
1. Cost of removal has not been included.

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

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**Generation Operations - LTSA-related O&M**

| Line No. | Year | (a) | (b) Covert Total | (c) DIG Total |
|---|---|---|---|---|
| 1 | 2020 | | | |
| 2 | 2021 | | - | - |
| 3 | 2022 | | - | - |
| 4 | 2023 | | 1,966 | - |
| 5 | 2024 | | 3,450 | - |
| 6 | 2025 | | 3,529 | 1,667 |
| 7 | 2026 | | 3,611 | 2,924 |
| 8 | 2027 | | 3,697 | 2,994 |
| 9 | 2028 | | 3,786 | 3,065 |
| 10 | 2029 | | 3,875 | 3,137 |
| 11 | 2030 | | 3,964 | 3,209 |
| 12 | 2031 | | 4,053 | 3,282 |
| 13 | 2032 | | 4,144 | 3,355 |
| 14 | 2033 | | 4,237 | 3,431 |
| 15 | 2034 | | 4,331 | 3,506 |
| 16 | 2035 | | 4,426 | 3,583 |
| 17 | 2036 | | 4,522 | 3,661 |
| 18 | 2037 | | 4,623 | 3,743 |
| 19 | 2038 | | 4,726 | 3,827 |
| 20 | 2039 | | 4,832 | 3,912 |
| 21 | 2040 | | 2,058 | 1,666 |
| 22 | Total | $ | 69,829 | $ 50,964 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

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**Generation Operations - non-LTSA O&M**

| Line No. | Year | (a) | (b) Covert Total | (c) DIG, Kalamazoo, Livingston Total |
|---|---|---|---|---|
| 1 | 2020 | | - | - |
| 2 | 2021 | | - | - |
| 3 | 2022 | | - | - |
| 4 | 2023 | | 16,009 | - |
| 5 | 2024 | | 28,393 | - |
| 6 | 2025 | | 29,004 | 20,774 |
| 7 | 2026 | | 29,289 | 33,806 |
| 8 | 2027 | | 29,519 | 33,841 |
| 9 | 2028 | | 28,816 | 33,773 |
| 10 | 2029 | | 29,300 | 34,024 |
| 11 | 2030 | | 29,205 | 34,009 |
| 12 | 2031 | | 29,295 | 35,178 |
| 13 | 2032 | | 29,120 | 35,675 |
| 14 | 2033 | | 30,490 | 35,998 |
| 15 | 2034 | | 30,868 | 37,078 |
| 16 | 2035 | | 31,444 | 37,174 |
| 17 | 2036 | | 31,443 | 37,075 |
| 18 | 2037 | | 31,130 | 38,790 |
| 19 | 2038 | | 31,793 | 38,860 |
| 20 | 2039 | | 32,863 | 40,584 |
| 21 | 2040 | | 13,204 | 16,619 |
| 22 | Total | $ | 511,184 | $ 543,256 |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Electric Capital Expenditures

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**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2023**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | (c) 2020-2031 Total |
|---|---|---|---|
| **Karn 3&4 Retirement Scenario** | | | |
| 1 | Karn 3&4 | Unavoidable | $ 6,950 |
| 2 | Karn 3&4 - Unit Separation | Unavoidable | $ 13,186 |
| 3 | Karn 1&2 | Unavoidable | $ 13,294 |
| 4 | Karn 3&4 | Avoidable | $ 75,648 |
| 5 | Karn 3&4 - Unit Separation | Avoidable | $ 15,465 |
| 6 | Karn 1&2 | Avoidable | $ - |
| 7 | Karn 3&4 | Incremental | $ - |
| 8 | Karn 1&2 | Incremental | $ - |

**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2024**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | | (c) 2020-2031 Total |
|---|---|---|---|---|
| **Campbell 1 Retirement Scenario** | | | | |
| 1 | Campbell 1 | Unavoidable | $ | 15,037 |
| 2 | Campbell 2 | Unavoidable | $ | 79,020 |
| 3 | Campbell 1 | Avoidable | $ | 42,840 |
| 4 | Campbell 2 | Incremental | $ | 253 |
| **Campbell 2 Retirement Scenario** | | | | |
| 5 | Campbell 1 | Unavoidable | $ | 57,878 |
| 6 | Campbell 2 | Unavoidable | $ | 22,950 |
| 7 | Campbell 2 | Avoidable | $ | 56,070 |
| 8 | Campbell 1 | Incremental | $ | 322 |
| **Campbell 1 and 2 Retirement Scenario** | | | | |
| 9 | Campbell 1 | Unavoidable | $ | 15,037 |
| 10 | Campbell 2 | Unavoidable | $ | 22,950 |
| 11 | Campbell 1 | Avoidable | $ | 42,840 |
| 12 | Campbell 2 | Avoidable | $ | 56,070 |
| 13 | Campbell 3 | Incremental | $ | - |

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Electric Capital Expenditures

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**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2025**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | (c) 2020-2031 Total |
|---|---|---|---|
| **Campbell 1 Retirement Scenario** | | | |
| 1 | Campbell 1 | Unavoidable | $ 21,926 |
| 2 | Campbell 2 | Unavoidable | $ 79,020 |
| 3 | Campbell 1 | Avoidable | $ 35,951 |
| 4 | Campbell 2 | Incremental | $ - |
| **Campbell 2 Retirement Scenario** | | | |
| 5 | Campbell 1 | Unavoidable | $ 57,878 |
| 6 | Campbell 2 | Unavoidable | $ 32,446 |
| 7 | Campbell 2 | Avoidable | $ 46,573 |
| 8 | Campbell 1 | Incremental | $ - |
| **Campbell 1 and 2 Retirement Scenario** | | | |
| 9 | Campbell 1 | Unavoidable | $ 21,926 |
| 10 | Campbell 2 | Unavoidable | $ 32,446 |
| 11 | Campbell 1 | Avoidable | $ 35,951 |
| 12 | Campbell 2 | Avoidable | $ 46,573 |
| 13 | Campbell 3 | Incremental | $ - |
| **Campbell 3 Retirement Scenario** | | | |
| 13 | Campbell 3 | Unavoidable | $ 59,291 |
| 14 | Campbell 3 - Unit Separation | Unavoidable | $ - |
| 15 | Campbell 3 | Avoidable | $ 136,306 |
| 16 | Campbell 3 - Unit Separation | Avoidable | $ (64,146) |
| 17 | Campbell 3 | Incremental | $ - |
| **Karn 3&4 Retirement Scenario** | | | |
| 18 | Karn 3&4 | Unavoidable | $ 19,611 |
| 19 | Karn 3&4 - Unit Separation | Unavoidable | $ 19,490 |
| 20 | Karn 1&2 | Unavoidable | $ 13,294 |
| 21 | Karn 3&4 | Avoidable | $ 62,987 |
| 22 | Karn 3&4 - Unit Separation | Avoidable | $ 9,161 |
| 23 | Karn 1&2 | Avoidable | $ - |
| 24 | Karn 3&4 | Incremental | $ - |
| 25 | Karn 1&2 | Incremental | $ - |

**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2026**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | | (c) 2020-2031 Total |
|---|---|---|---|---|
| **Campbell 1 Retirement Scenario** | | | | |
| 1 | Campbell 1 | Unavoidable | $ | 23,831 |
| 2 | Campbell 2 | Unavoidable | $ | 79,020 |
| 3 | Campbell 1 | Avoidable | $ | 34,046 |
| 4 | Campbell 2 | Incremental | $ | - |
| **Campbell 2 Retirement Scenario** | | | | |
| 5 | Campbell 1 | Unavoidable | $ | 57,878 |
| 6 | Campbell 2 | Unavoidable | $ | 33,746 |
| 7 | Campbell 2 | Avoidable | $ | 45,273 |
| 8 | Campbell 1 | Incremental | $ | - |
| **Campbell 1 and 2 Retirement Scenario** | | | | |
| 9 | Campbell 1 | Unavoidable | $ | 23,831 |
| 10 | Campbell 2 | Unavoidable | $ | 33,746 |
| 11 | Campbell 1 | Avoidable | $ | 34,046 |
| 12 | Campbell 2 | Avoidable | $ | 45,273 |

**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2028**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | | (c) 2020-2031 Total |
|---|---|---|---|---|
| **Campbell 1 Retirement Scenario** | | | | |
| 1 | Campbell 1 | Unavoidable | $ | 43,436 |
| 2 | Campbell 2 | Unavoidable | $ | 79,020 |
| 3 | Campbell 1 | Avoidable | $ | 14,442 |
| 4 | Campbell 2 | Incremental | $ | - |
| **Campbell 2 Retirement Scenario** | | | | |
| 5 | Campbell 1 | Unavoidable | $ | 57,878 |
| 6 | Campbell 2 | Unavoidable | $ | 60,687 |
| 7 | Campbell 2 | Avoidable | $ | (18,333) |
| 8 | Campbell 1 | Incremental | $ | - |
| **Campbell 1 and 2 Retirement Scenario** | | | | |
| 9 | Campbell 1 | Unavoidable | $ | 43,436 |
| 10 | Campbell 2 | Unavoidable | $ | 60,687 |
| 11 | Campbell 1 | Avoidable | $ | 14,442 |
| 12 | Campbell 2 | Avoidable | $ | 18,333 |
| 13 | Campbell 3 | Incremental | $ | - |

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Consumers Energy Company
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**Generation Capital Expenditures**
**AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2032**
**($000's)**

| Line No. | (a) Unit | (b) Cost Type | (c) 2020-2039 Total |
|---|---|---|---|
| **Campbell 3 Retirement Scenario** | | | |
| 1 | Campbell 3 | Unavoidable | $ 157,697 |
| 2 | Campbell 3 - Unit Separation | Unavoidable | $ - |
| 3 | Campbell 3 | Avoidable | $ 37,900 |
| 4 | Campbell 3 - Unit Separation | Avoidable | $ (64,146) |
| 5 | Campbell 3 | Incremental | $ - |

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for Approval of an Integrated Resource Plan<br>under MCL 460.6t, certain accounting<br>approvals, and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21090 |

# REVISED DIRECT TESTIMONY

# OF

# KEITH G. TROYER

# ON BEHALF OF

# CONSUMERS ENERGY COMPANY

October 2021

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

A. My name is Keith G. Troyer, 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 Director of Electric Grid Integration Contracts and Settlements in the Electric Supply Section of the Electric Grid Integration Department.

## QUALIFICATIONS

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

A. I received the degree of Bachelor of Science in Engineering with a specialty in Civil Engineering from Michigan State University in 2008. In 2015, I became a Registered Professional Engineer in the state of Michigan. In 2018, I received a Master of Business Administration ("MBA") through Michigan State University's Executive MBA Program.

In July 2009, I joined Consumers Energy as an Electric System Owner. In January 2011, I accepted a position as an Engineer in the Transactions and Resource Planning Section of the Energy Supply Department. In that role, I was responsible for administration and coordination of the Company's Experimental Advanced Renewable Program ("EARP") – Solar, part of the Company's Renewable Energy Plan ("RE Plan"). I was involved in the development and implementation of the EARP-Solar expansion in 2011. In June 2013, I began taking on additional responsibilities associated with the RE Plan, including the calculation of the Transfer Price associated with renewable energy and capacity and the tracking of Renewable Energy Credits ("RECs"). In 2014, I was also

responsible for supervision of the implementation of the EARP-Anaerobic Digestion pilot. In December 2016, I transitioned to a new role where my supervisory and direct responsibilities included administering Power Purchase Agreements ("PPAs"), issuing solicitations for energy and capacity, and managing the Company's capacity position with Midcontinent Independent System Operator, Inc. ("MISO"). In September 2019, I became the Director of Electric Grid Integration Contracts and Settlements.

**Q. What are your responsibilities as Director of Electric Grid Integration Contracts and Settlements?**

A. My responsibilities include oversight of the Company's distribution agreements and programs, PPAs, solicitations for energy and capacity, renewable energy compliance, and electric wholesale settlement activities.

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

A. Yes. I provided testimony in:

- MPSC Case No. U-17095-R (direct), the Company's 2013 Power Supply Cost Recovery ("PSCR") Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-17631 (direct), the Company's 2013 RE Reconciliation Case, regarding 2013 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;
- MPSC Case No. U-17317-R (direct), the Company's 2014 PSCR Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR;
- MPSC Case No. U-17792 (direct and rebuttal), the 2015 biennial review of the Company's RE Plan, regarding RE Plan expenses recovered through the PSCR, RE compliance, new renewable capacity compliance, and RE programs;
- MPSC Case No. U-17803 (direct), the Company's 2014 Renewable Cost Reconciliation Case, regarding 2014 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- MPSC Case No. U-17678-R (direct), the Company's 2015 PSCR Reconciliation Case, regarding 2015 RE Plan expenses recovered through PSCR;

- MPSC Case No. U-17918 (rebuttal), the Company's 2016 PSCR Plan and five-year forecast, regarding the impacts of net electric metering on energy supply;

- MPSC Case No. U-18081 (direct and revised), the Company's 2015 Renewable Reconciliation case, regarding 2015 RE Plan expenses recovered through PSCR, RE compliance, and new renewable capacity compliance;

- MPSC Case No. U-18090 (direct, rebuttal, reopened rebuttal, and second reopened rebuttal, and affidavit), the Company's 2016 Public Utility Regulatory Policies Act of 1978 ("PURPA") case to establish a method and calculation for avoided costs;

- MPSC Case No. U-17918-R (direct), the Company's 2016 PSCR Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;

- MPSC Case No. U-18241 (direct), the Company's 2016 RE Cost Reconciliation Case, regarding 2016 RE Plan expenses recovered through PSCR;

- MPSC Case No. U-18402 (direct and rebuttal), the Company's 2018 PSCR Plan and five-year forecast, regarding long-term PPAs and capacity forecast;

- MPSC Case No. U-18231 (direct and rebuttal), the 2017 biennial review of the Company's RE Plan, regarding the Company's Request for Proposal process for new resources, the cost of new RE resources included in the RE Plan, and the risks that may drive performance to vary, associated with these topics;

- MPSC Case No. U-18351 (rebuttal), the Company's 2017 Application to comply with Section 61 of 2016 PA 342, regarding customer credits in voluntary RE programs and competitive solicitations;

- MPSC Case No. U-20165 (direct, rebuttal, and second rebuttal), the Company's 2018 Integrated Resource Plan ("IRP"), regarding long-term PPAs, proposed changes to the Company's PURPA avoided cost implementation, the Company's proposal to utilize competitive solicitations and the implementation of the Financial Compensation Mechanism ("FCM");

- MPSC Case No. U-20219 (direct and rebuttal), the Company's 2019 PSCR Plan and five-year forecast, regarding long term PPAs and MISO revenue and expenses;

- MPSC Case No. U-20202 (direct), the Company's 2018 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund.;

- MPSC Case No. U-20469 (affidavit), the Company's Application requesting an Order Rescinding Avoided Cost Rates, regarding the Company's avoided costs, obligations to enter new PPAs, and establishment of new avoided costs in the Company's IRP;

- MPSC Case No. U-20496 (direct), the Company's Application for approval of Amendments to the PPA with Viking Energy of Lincoln, LLC, Viking Energy of McBain, LLC, and Hillman Power Company;

- MPSC Case No. U-20604 (direct), the Company's Application for approval of PPAs;

- MPSC Case No. U-15805-S (affidavit), the Company's Application for approval of a renewable energy purchase agreement with River Fork Solar, LLC.

- MPSC Case No. U-20525 (direct and rebuttal), the Company's 2020 PSCR Plan and five-year forecast, regarding long-term PPAs and the treatment of MISO revenue and expenses;

- MPSC Case No. U-20697 (direct and rebuttal), the Company's 2020 electric rate case, regarding PSCR expenses, transmission cost analysis, state reliability mechanism methodology, and IRP supply implementation activities;

- MPSC Case No. U-20220 (direct), the Company's 2019 PSCR Reconciliation Case, regarding purchased power supply costs and the allocation of costs to the renewable resource fund;

- MPSC Case No. U-15805-T (affidavit), the Company's Application for approval of amended renewable energy and PPAs with North American - Central LLC;

- MPSC Case No. U-20833 (direct), the Company's Application for approval of PPAs with STS Hydropower LLC;

- MPSC Case No. U-20838 (direct), the Company's Application for approval of new PPAs with members of the Independent Power Producers Coalition of Michigan;

- MPSC Case No. U-20734 (direct), the Company's Application for approval of an amendment to the PPA with Entergy Nuclear Power Marketing, LLC; and

- MPSC Case No. U-20896 (direct), the Company's Application for approval of an amendment to the PPA with Midland Cogeneration Venture Limited Partnership.

**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:

- Provide an overview of the key input assumptions in this IRP related to the Company's existing and anticipated PPAs;
- Provide an overview of the MPSC Staff's ("Staff") Customer Distributed Generation ("DG") Program proposal, as included in the 2018 IRP Settlement Agreement approved in Case No. U-20165, and discuss the Company's consideration of that proposal;
- Detail the proposed changes to the Company's Financial Compensation Mechanism ("FCM");
- Provide an overview of the Company's implementation of PURPA avoided costs and detail the proposed changes to the Company's PURPA avoided cost implementation;
- Provide an overview of the Company's IRP-based competitive solicitations and detail the proposed changes to the Company's IRP-based competitive solicitations;
- Provide an overview of the Company's research on best practices for competitive procurement of renewable PPAs; and
- Provide an overview of the Company's 2021 Natural Gas Plant Request for Proposals ("RFP").

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

A. First, I provide a summary of the existing PPAs that have been executed by the Company and approved by the Commission. Then, I will discuss the assumptions related to: (i) the expected commercial operation date and execution of new PURPA-based contracts; (ii) the assumed PPA additions resulting from the annual IRP competitive solicitations issued in 2019 through 2021 to meet the Proposed Course of Action ("PCA") approved in the 2018

IRP Settlement Agreement, for commercial operation dates in 2022 through 2024; and (iii) the treatment of PPAs with contract expirations that occur during a MISO Planning Year.[1] Then, I will provide an overview of Staff's Customer DG Program proposal, as included in the 2018 IRP Settlement Agreement approved in Case No. U-20165 ("IRP Settlement Agreement"), and discuss the Company's consideration of that proposal. Next, I will provide an overview of the Company's proposed changes to the applicability and implementation of the FCM for new PPAs. Then, I will provide a summary of the Company's most recent avoided cost proceeding including the methodology and implementation procedures approved by the Commission. Next, I will discuss proposed changes to the avoided cost methodology and implementation procedures to better align with the Company's long-term capacity needs included in this IRP. Then, I will provide a summary of the Company's competitive procurement process for IRP-based supply-side resources including: (i) an overview of the solicitations issued in accordance with the IRP Settlement Agreement; (ii) proposed updates, clarifications, and enhancements for future IRP-based competitive solicitations; and (iii) the role of the Independent Administrator for future IRP-based competitive solicitations. Next, I will discuss the research conducted by the Company's consultant on best practices for the competitive procurement of renewable PPAs. Lastly, I will discuss the 2021 Natural Gas Plant RFP issued by the Company in January 2021 to support this IRP filing.

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

A. Yes. I am sponsoring the following exhibits:

[1] MISO defines a Planning Year as the 12-month period beginning June 1 of one year and concluding May 31 of the following year.

| | |
|---|---|
| Exhibit A-45 (KGT-1) | Purchase Power Contract Rates and MPSC Approval Orders; |
| Exhibit A-46 (KGT-2) | Procurement Trends and Potential Strategies for Renewable PPAs; |
| Exhibit A-47 (KGT-3) | U-20697 Embedded Capacity Costs - $/Peak kW Sales; |
| Exhibit A-48 (KGT-4) | Report of the Independent Administrator dated March 18, 2020; and |
| Exhibit A-49 (KGT-5) | Charles River Associates, Inc. ("CRA") Recommendation Letter. |

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

A. Yes.

**SECTION I: KEY INPUTS ASSUMPTIONS RELATED TO PPAs**

**Q. Are you familiar with the Company's PPAs for energy and capacity?**

A. Yes. As the Director of the Electric Grid Integration Contracts and Settlements at Consumers Energy, I am responsible for oversight of negotiation, execution, and administration of the Company's PPAs.

**Q. Please summarize how the Company's PPAs are included in the modeling assumptions for this proceeding.**

A. The Company has or expects to have 125 long-term PPAs (including proxy assumptions) in place representing 4,107 MW of contract capacity with independent power producers for the purchase of energy, capacity, and/or RECs. Of the 125 PPAs the Company has in place, 100 PPAs are for the purchase of energy and capacity, 3 PPAs provide renewable energy under the Renewable Resource Program (a.k.a. Green Generation Program), 11 PPAs provide renewable energy under the RE Plan, and 3 PPAs are in place under the EARP-Anaerobic Digestion Program. Additionally, the Company has executed 8 contracts

for the purchase of energy and has 379 contracts in place for the purchase of solar energy, capacity, and RECs as part of the EARP-Solar Program.

**Q. Please explain Exhibit A-45 (KGT-1).**

A. Exhibit A-45 (KGT-1) is a list of the contracts that the Company currently has or expects to have in place as a base modeling assumption during the IRP study period. Exhibit A-45 (KGT-1), column (a), lists the current counterparties with which the Company has previously executed a contract. Column (b) shows the amount of contract capacity that the Company purchases under each contract. Column (c) shows the fuel used to generate electricity under the PPA. Column (d) shows the Commission order that approved each PPA. Column (e) shows the expected termination date specified for each PPA. Column (f) shows the entities up to the size of the Company's PURPA purchase obligation threshold (currently 20 MW in size) that the Company anticipates will enter into new PURPA contracts with the Company upon termination of their current PPAs.

**Q. What assumptions are included in the IRP modeling for PPAs?**

A. The expected production and associated expense from the PPAs are included as part of the Company's supply portfolio through the expected termination of the agreements shown in Exhibit A-45 (KGT-1), column (d). The Company forecasts that at the conclusion of their existing PPAs, the counterparties with renewable generators that have contracts for energy and capacity, as part of the Renewable Resource Program, or as part of the Company's Renewable Energy Plan shown on Exhibit A-45 (KGT-1), up to 20 MW in size will sign new PURPA contracts with the Company at rates similar to the PPA with River Fork Solar. These facilities are identified in column (f).

**Q. Are there any bilateral purchase agreements for energy or capacity included in this IRP?**

A. No.

**Q. Are there any PPAs included in this IRP that have not been previously approved by the Commission?**

A. Yes. The Commission's September 11, 2019 Order in Case No. U-20615 approved a settlement agreement between the Company and various developers to resolve outstanding rights and claims to new PURPA PPAs ("PURPA Settlement Agreement"). The PURPA Settlement Agreement resulted in the execution of 170 MW of PURPA PPAs in the Company's PURPA queue at the full PURPA avoided cost from Case No. U-18090, which is 20 MW more than the amount included in the Company's 2018 IRP in Case No. U-20165. Additionally, the PURPA Settlement Agreement resulted in the award of 414 MW of PURPA PPA entitlements at the Company's reduced avoided cost from Case No. U-18090. In accordance with the PURPA Settlement Agreement, qualifying facilities ("QFs") that have entered into a PPA as a result of the 414 MW of entitlement, are permitted to terminate and replace executed PPAs with new PPAs that meet the requirements of the PURPA Settlement Agreement. The process of terminating and replacing PPAs causes some ambiguity in the modeling assumptions used in the preparation of this IRP. Thus, the Company has assumed that the PPAs included in the 584 MW of capacity in the PURPA Settlement Agreement will begin commercial operation on the Expected Start Date included in each PPA as was known on June 1, 2020. All of the PPAs executed as part of the 584 MW utilize solar photovoltaic technology for generation. These contracts are included in Exhibit A-45 (KGT-1), rows 1 through 96.

The Company has executed only 574 MW of the total 584 MW of PURPA capacity and has therefore included a proxy PPA shown as the PURPA Aggregate on row 97 of Exhibit A-45 (KGT-1). Additionally, Exhibit A-45 (KGT-1) shows placeholders for the new PPAs that it expects to enter into as a result of the IRP Settlement Agreement from the 2019 through 2021 solar competitive solicitations for facilities that are expected to begin commercial operation in 2022 through 2024.

**Q. How has the Company included the new IRP PCA PPAs in this filing?**

A. Similar to the treatment of PURPA PPAs, the Company locked in assumptions regarding the new IRP PCA PPAs on June 1, 2020. At that time, the Company had not yet executed any PPAs as a result of the 2019 or later solicitations.[2] The IRP Settlement Agreement requires at least 50% of new solar capacity to come from PPAs in each annual solicitation. Therefore, the Company has assumed June 1st start dates for half of the solicitation capacity through new solar PPAs beginning operation in 2022 through 2024 as shown in Exhibit A-45 (KGT-1), rows 98 through 100.

**Q. How are the PPAs represented in this filing with respect to their capacity contribution towards the Company's planning reserve margin requirements from MISO?**

A. MISO requires the Company to fulfill its capacity needs for the entire Planning Year which begins June 1st and ends May 31st. If a contract for energy and capacity or as part of the Renewable Resource Program terminates before the end of the Planning Year, it does not fulfill MISO's requirements and is not included as a capacity resource for the Planning

[2] The Commission's April 8, 2021 Order in Case No. U-20165 approved the 140 MW PPA with Calhoun Solar Energy, LLC from the 2019 IRP competitive solicitation. 10 MW from the 2019 competitive solicitation has been made available to PURPA QFs at the avoided cost set in accordance with the IRP Settlement Agreement from the 2019 solicitation results.

Year.[3] For example, prior to the recent amendment, the Company's PPA with the Palisades Nuclear Plant ended on April 11th, 2022, which occurred during the Planning Year that began June 1, 2021.[4] Since the PPA did not continue through May 31, 2022, the capacity would not be included in the forecast of Company resources for Planning Year 2021/2022 (i.e. Planning Year 2021). The amount of capacity expected to be supplied by each PPA, as well as the 10 MW of new PURPA solar PPA(s) and the 550 MW of new IRP PPA solar from the 2019 through 2021 solicitations, is shown on Exhibit A-6 (STW-3), sponsored by Company witness Sara T. Walz.

**Q. Does the Company have any generation in its supply portfolio sourced from nuclear technology?**

A. Yes. While the Company does not own any nuclear fueled generation, it has an existing PPA with Entergy Nuclear Power Marketing, LLC for the output of the Palisades Nuclear Plant. The PPA was most recently amended on January 28, 2020 to extend the termination of the PPA from April 11, 2022 to May 31, 2022. This amendment was approved by the Commission's August 20, 2020 Order Approving a Settlement Agreement in Case No. U-20734.

## SECTION II: Staff's Customer DG Program Proposal

**Q. Are you familiar with the IRP Settlement Agreement provision related to DG?**

A. Yes. As part of the IRP Settlement Agreement, the Company agreed that its next IRP would include consideration of a DG program, similar to Staff's Customer DG Program proposed by Staff witness Meredith A. Hadala in her direct testimony in Case No. U-20165.

[3] The Company has included the entire capacity from the MCV PPA through Planning Year 2029/2030.
[4] As discussed below, the Commission recently approved an amendment to the Palisades Nuclear Plant PPA which extended the term through May 31, 2022 and will allow the Company to rely on the capacity provided by the PPA for the entire 2021 MISO Planning Year. See Case No. U-20734.

**Q. What was the underlying objective of the IRP settlement provision?**

A. A key objective of including this provision in the settlement agreement was to facilitate increased access to customer rooftop solar. In Case No. U-20165, Staff proposed that "…2% of the capacity planned to be acquired in every competitive solicitation be reserved for a Customer Distributed Generation program."

**Q. What actions has the Company taken regarding DG since the IRP Settlement Agreement?**

A. Since the IRP Settlement Agreement, the Company has taken steps to expand customer access to distributed generation. On November 19, 2020, the Company reached its statutory cap of 1% on Category 1 and Category 2 distributed generation.[5] In an effort to expand customer access to rooftop solar until an alternative compensation methodology is established, the Company voluntarily doubled its distributed generation program's cap to 2% of average peak load on January 1, 2021. See MPSC Case No. U-20697, December 17, 2020 Order, page 310.

**Q. Why did the Company voluntarily increase the size of its DG program?**

A. The Company's decision to voluntarily double its DG program showcases the Company's support for customers who wish to install rooftop solar generation. The Company continues to advocate for DG policy provisions that prioritize the needs of all customers in Michigan, recognizing that the expansion of the cap is a simple, albeit temporary solution. Solar plays an important role in the Company's Clean Energy Plan, and the Company fully supports continuing to develop clean energy in Michigan. Voluntarily increasing the 1% statutory DG cap to 2% ensures that customers have expanded access to rooftop solar.

[5] See the Company's November 19, 2020 filing in Case No. U-15787.

**Q. Does this voluntarily expansion of the Company's DG program address the objectives of the IRP's settlement provisions?**

A. Yes. The voluntary expansion of the Company's DG tariff achieves the goal of facilitating increased customer access to rooftop solar.

**Q. Has the Company considered Staff's Customer DG Program proposed in Case No. U-20165?**

A. Yes. The Company has considered Staff's proposal and believes that it is unnecessary due to the voluntary expansion of the Company's DG tariff.

## SECTION III: FCM IMPLEMENTATION

**Q. Are you familiar with the Company's FCM?**

A. Yes, I sponsored testimony in the Company's 2018 IRP and 2021 Electric Rate case, Case No. U-20697, related to the implementation of the FCM on new PPAs.

**Q. Is the Company proposing to make any changes to the implementation of the FCM?**

A. Yes. The Company is proposing two changes to the implementation of the FCM. First, the IRP Settlement Agreement establishes an annual cap on the maximum PPA rate that is eligible for FCM. The Company proposes to remove the FCM cap for several reasons. The FCM cap is based on a $/MWh limit which does not align with the Company's current compensation structure in PPAs which include a capacity payment based on $/ZRC-day or $/ZRC-month, and an energy payment based on $/MWh. Because of this disconnect in cap and compensation structure, the Company is limited in the amount of FCM it is able to recover for PPAs. For example, if the Company only procures ZRCs and/or RECs and not the associated energy, it would be prohibited from collecting any FCM on the PPA. Similarly, the FCM cap unfairly restricts the Company's ability to recover an appropriate

amount of FCM on dispatchable resources, where the energy production may be significantly reduced in order to improve the PPAs responsiveness to energy market signals.

Second, the FCM is currently applicable to only new PPAs that are not included in the Company's RE Plan. This limitation disincentivizes the pursuit of PPAs, in lieu of Company-owned generation, as part of the RE Plan. Additionally, the Company is not able to apply the FCM to PPA amendments which disincentivizes the pursuit of contract extensions through bilateral negotiations. For example, if the Company wishes to delay the construction of a new generator by negotiating a 10-year extension on a PPA, it would not be permitted to receive an FCM on the PPA to delay the new generator even though the PPA would be substantially replacing the new generation resource. Rather, in this example, the Company would be incentivized to sign a new 10-year PPA or construct the new generation resource, both potentially at a higher cost, than the existing PPA that is available for consideration. For these reasons, the Company proposes that the FCM be applicable to all new PPAs, including RE Plan PPAs, as well as all PPA amendments, except affiliate PPAs which are prohibited by law.

## SECTION IV: IMPLEMENTATION OF PURPA AVOIDED COSTS

**Q. Are you familiar with the Company's implementation of PURPA avoided costs in accordance with the IRP Settlement Agreement?**

A. Yes. I sponsored testimony related to the Company's PURPA avoided cost construct in Case No. U-18090 and the Company's 2018 IRP. Most recently, I submitted testimony, exhibits, and an affidavit to reset the PURPA full avoided cost rate in Case No. U-20165 in accordance with the IRP Settlement Agreement. I have management oversight of the

administration of all PPAs and distribution agreements, as well as monthly settlements with MISO and QFs.

**Q. What are avoided costs?**

A. This term comes from the Federal Energy Regulatory Commission ("FERC") rules established and embodied in the Code of Federal Regulations, where "avoided costs" are defined as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

**Q. What is a QF?**

A. A QF can be either a qualifying small power production facility or a qualifying cogeneration facility that meets certain size, fuel, and/or efficiency standards.

**Q. Are QFs required to sell their energy and/or capacity at avoided costs?**

A. No. These generating facilities can enter into negotiated PPAs with the Company or others or to submit bids in response to RFPs issued by the Company or others that seek to acquire energy and/or capacity.

**Q. Do QFs have an obligation to execute contracts with the Company?**

A. No. QFs have the option to enter into PURPA contracts with the Company but may also participate in the wholesale market or sell to other utilities at negotiated rates.

**Q. Does the Company have an obligation to execute PURPA contracts with QFs?**

A. Yes. The Company generally has an obligation to enter into contracts for energy and capacity up to its purchase obligation threshold (currently 20 MW in size[6]) with QFs that

[6] On June 14, 2021, the Company filed an application with FERC to reduce the must buy obligation threshold to 5 MW for qualifying small power production facilities in accordance with FERC Order 872. The FERC application does not apply to qualifying cogeneration facilities.

both (i) are capable of delivering energy and capacity to the Company and (ii) do not have nondiscriminatory access to wholesale markets. Throughout my direct testimony, when discussing QFs, I am referring to facilities up to the size of the Company's must buy obligation threshold that meet the requirements to be certified as a QF, unless otherwise noted.

**Q. Please describe the Company's currently approved PURPA avoided cost construct.**

A. On May 26, 2021, the Commission issued an Order in Case No. U-20165 approving new PURPA full avoided cost rates, including updates to the Standard Offer Tariff and associated Standard Offer Contract that were updated in accordance with the IRP Settlement Agreement. Under this existing construct, the Standard Offer Tariff and Standard Offer Contract are available for QFs up to 2 MW in size. In accordance with the IRP Settlement Agreement, "the full avoided cost rate offered will be equal to the highest priced proposal that received a contract in the competitive solicitation and the contract length will be the same as offered in the competitive solicitation."

The Company currently offers both full avoided costs and reduced avoided costs rates for PURPA QFs. The current reduced avoided cost rate is based on the MISO Planning Resource Auction ("PRA") capacity rate, adjusted annually, and either (i) a 10-year term based on the forecast of LMPs for the first five years and year six through year 10 equal to the energy price in the fifth year of the LMP forecast, or (ii) actual LMPs for 15 years. Regardless of whether a PURPA contract is based on full avoided cost or reduced avoided cost, QFs that enter into a PPA are not required to transfer RECs to the Company, but the QF and Company can negotiate a separate agreement for the RECs at a mutually agreed upon price.

**Q. Please explain the circumstances in which a QF is currently eligible to receive full avoided cost rates.**

A. While the Company is proposing several prospective changes to its PURPA avoided cost construct as further detailed below, there are several methods by which a QF can *currently* pursue contracts with the Company:

1. Any QF up to the Company's must buy obligation threshold can participate in the Company's competitive solicitations, regardless of the technology specified, and receive the rate[7] included in their proposal, if selected;

2. Any remaining capacity solicited but not filled through each solicitation is made available to QFs on a first-come, first-served basis at the full avoided cost rates based on that solicitation;

3. Any QF with an existing PPA as of January 1, 2019 with an expiring full avoided cost PURPA PPA for energy and capacity is eligible to receive the most recently Commission-approved full avoided cost rate for a new PPA; and

4. QFs up to 150 kW that request the Standard Offer Contract will receive the most recently Commission-approved full avoided cost rates.

**Q. Is the Company proposing to make any changes to its currently approved PURPA avoided cost construct?**

A. Yes. There are several adjustments to the current PURPA avoided cost review and implementation that should be adopted.

**Q. What changes does the Company propose to make to its review of PURPA avoided costs?**

A. The Company requests that the Commission clarify that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that

[7] QFs participating in the solicitation are treated as other respondents to the solicitation which requires meeting the eligibility requirements of the solicitation and will result in the transfer of RECs, if applicable, to the Company under the solicitation-based PPA.

the Company has agreed to file every three years.[8] Previously, the Commission's May 31, 2017, Order in Case No. U-18090 required a biennial review of the Company's PURPA avoided costs. See Case No. U-18090, May 31, 2017 Opinion and Order, page 28. This application is being filed approximately 2 years from the approval of the IRP Settlement Agreement, which resulted in the approval of the Company's current PURPA avoided cost construct. Long-term planning, including both PURPA and non-PURPA resources, is most adequately addressed in IRP filings, and the Company intends to continue to update PURPA avoided costs following the conclusion of each annual IRP solar solicitation. As the Company intends to continue filing IRPs every three years to implement the buildout of solar resource additions, the Company requests that the Commission clarify, or in the alternative modify, its previous order in Case No. U-18090 and find that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that the Company has agreed to file every three years.

**Q. Has the Commission previously indicated a willingness to examine avoided costs as part of an IRP proceeding?**

A. Yes. The Commission's November 21, 2017 Order in Case No. U-18090 states :

> Going forward, the Commission believes that PURPA avoided costs should be integrated with capacity demonstration and IRP proceedings in order to more accurately assess capacity needs. The IRP proceedings are conducive to updating avoided costs, because the Commission will already be evaluating, in detail, utility-specific plans for any incremental generation or purchases along with their associated costs.

The Company views this language as support by the Commission to include both an update to avoided costs and review of the Company's capacity needs in this IRP, and all IRPs

[8] As explained by Company witness Richard T. Blumenstock, the Company's agreement to continue to file IRPs on a three-year basis is conditioned on the approval of the Company's PCA.

going forward. Additionally, it should be noted that, in Case No. U-20905 *et al.*, the Commission indicated that it "will consider in the next biennial review for each utility whether review on a biennial basis or a less frequent review is appropriate." Case No. U-20905 *et al.*, January 21, 2021 Order, page 27.

**Q. What changes does the Company propose to make to its implementation of PURPA avoided costs?**

A. There are several changes that the Company proposes to make to the implementation of PURPA avoided costs. These changes pertain to eligibility for full avoided cost rates and the Standard Offer.

**Q. Please explain the Company's proposed changes to eligibility for full avoided cost rates.**

A. As explained above, there are multiple ways in which full avoided costs are *currently* available to QFs. Given the findings in FERC's July 16, 2020 Order, 172 FERC ¶ 61,041 ("FERC Order 872"), and November 19, 2020 Order, 173 FERC ¶ 61,158 ("FERC Order 872-A"), the Company proposes to remove two options from the Company's PURPA full avoided cost construct: (i) eligible QFs up to 150 kW that request the Standard Offer Contract are eligible to receive the most recent Commission-approved full avoided cost rates; and (ii) when there is remaining unfilled capacity from an annual solicitation, the unfilled capacity is made available to QFs on a first-come, first-served basis.

FERC Order 872 explains that when a competitive solicitation process is used to meet a utility's full capacity needs, a utility is not required to enter into PURPA contracts for capacity outside of that competitive solicitation process. FERC Order 872, page 236. FERC further explained that "[t]his approach further shields purchasing electric utilities

from situations... where QFs could simply sit out the competitive solicitation process (or participate but not have their bids accepted), but then seek to sell capacity to the purchasing electric utility and to receive a separate higher administratively-determined avoided cost rate including an avoided cost capacity rate, and even potentially displace non-QF competitive solicitation winners." FERC Order 872, page 237. Therefore, since the Company is using a competitive solicitation approach, in which QFs sized 150 kW or less are able to participate, for acquiring the Company's full capacity needs, there is no basis to require the Company to pay full avoided cost rates (which include a capacity component) to QFs 150 kW and below. QFs 150 kW and below would still remain eligible for standard, reduced avoided cost rates like any other QF.

Furthermore, on January 1, 2021, the Company increased the size of its DG Program from 1% to 2% of the Company's peak load as previously discussed to continue providing an opportunity for customers to install solar on their homes and businesses using the Company's well-established program. Additionally, since the Commission's approval of the IRP Settlement Agreement, the Company has neither (i) executed any Standard Offer Contracts with QFs up to 150 kW in size, nor (ii) been contacted by a generator up to 150 kW in size claiming to be a QF or asking for a PURPA-based PPA. It is apparent that customers are not seeking to execute PURPA-based PPAs up to 150 kW in size, but instead are interested and applying for the DG program. For these reasons, QFs up to 150 kW in size should only be eligible to receive full avoided cost rates if they meet the full avoided cost eligibility that all other QFs must meet.

Providing QFs with capacity unfilled by the Company's annual solicitations is also inconsistent with FERC Order 872. The Company is proposing to satisfy its full

supply-side capacity needs through its annual solicitations and permits all QFs up to the Company's PURPA purchase obligation threshold to participation in those solicitations. Pursuant to FERC Order 872, since the Company is meeting its full capacity needs in its annual solicitation, the Company's avoided capacity cost is zero and the Company is not required to enter into PURPA contracts for capacity outside of that competitive solicitation process. Therefore, QFs should not be eligible for the Company's full avoided cost rates outside of the Company's annual competitive solicitation process. Moreover, as discussed in more detail below, the Company is proposing greater flexibility in the amount of MWs acquired in each competitive solicitation and a reconciliation process in future IRPs which means that it will not be known on an annual basis if there is open capacity to offer QFs. In other words, under the Company's proposed PCA, the amount of capacity acquired in any one year or any one solicitation would not necessarily be indicative of a capacity need that could or should be filled by PURPA QFs outside of the solicitation process. Instead, the Company's PCA will employ multiple solicitations over multiple years to fill an overall capacity need in a more flexible manner.

Through participation in the annual solicitation process, QFs have an opportunity to secure contracts with the Company by winning the solicitation or may receive standard, reduced avoided cost rates for energy, over a fixed term, consistent with the Company's currently approved methodology for such rates.

While the Company is proposing the above changes to QF eligibility for full avoided cost rates, the Company is not proposing any changes to the eligibility of certain existing QFs with respect to the Company's full avoided cost rates. The IRP Settlement Agreement provided that any QF with an existing PPA as of January 1, 2019 with an

expiring full avoided cost PURPA PPA for energy and capacity is eligible to receive the most recently Commission-approved full avoided cost rate for a new PPA. So long as a QF has an existing PPA as of January 1, 2019, the Company agrees to pay those QFs the Company's currently approved full avoided cost rates at the time of PPA expiration. QFs with PPAs entered after January 1, 2019 would need to enter future competitive solicitations to secure contracts with the Company, in accordance with the direction in FERC Order 872.

**Q. How should the Company's PURPA capacity needs be determined?**

A. Pursuant to the process approved in the IRP Settlement Agreement, and the direction provided by FERC in FERC Order 872, the Company has no PURPA capacity need so long as the Company is implementing a competitive biddings process to acquire its full capacity needs. Since the Company's PCA presents the capacity needs of the Company, the Company requests a finding from the Commission in this proceeding that the Company has no capacity need so long as the Company is implementing the PCA, including the competitive bidding process for all future capacity needs.

**Q. Please explain the Company's proposed change to the eligibility for the Standard Offer.**

A. Currently, QFs up to 2 MW in size are eligible for the Company's Standard Offer PPA. The Company proposes to reduce the size of the Standard Offer Contract and Standard Offer Tariff to 100 kW. There are numerous reasons for this proposal. First, 18 CFR 292.304(c) requires utilities to implement a Standard Offer Program for QFs up to 100 kW in size, making the Company's proposal consistent with FERC's PURPA regulations. Second, Standard Offer Tariff rates are most appropriate for small developers and

customers that lack the experience and resources needed for larger forays into the electricity generation business. The current Standard Offer Tariff size extends to developers who have significant experience and resources, and who do not need to have their contracting facilitated through a Standard Offer Tariff. The majority of requests for Standard Offer PPAs come from large sophisticated solar project developers and, based on the Company's experience, these developers have or are in the process of developing larger solar projects at or above 5 MW. For instance, the PURPA Settlement Agreement in Case No. U-20615 resulted in the execution of 22 PPAs with QFs up to 2 MW in size and 21 of those PPAs are under development with a subsidiary or an affiliate of a sophisticated solar development company.[9] Third, FERC Order 2222 requires that MISO develop a process by which distributed energy resources 100 kW and larger can participate in the wholesale market. Since distributed energy resources 100 kW and larger can participate in the wholesale market, providing the Standard Offer to facilities over 100 kW is unnecessary.

**Q. Is the Company's proposed change to the eligibility for the Standard Offer consistent with the MPSC's previous direction?**

A. Yes. In Case No. U-20905 *et al.*, the Commission found the following with respect to the Standard Offer cap:

> …should a utility receive authorization from FERC to terminate its obligation to purchase from QFs above 5 MW, the Commission directs the utility, in its next avoided cost review that follows the termination, to explain and support its position on the standard offer cap. Should a utility not propose a standard offer cap being set at 5 MW, it should provide a rationale as to why such a standard offer cap is not appropriate. [Case No. U-20905 *et al.*, January 21, 2021 Order, page 26.]

[9] Three projects are associated with NextSun Energy LLC. Three projects are associated with Inman Solar LLC. 15 projects are associated with Pine Gate Renewables and/or Albedo Development Company.

While the Company has not received FERC authorization to lower its PURPA must buy obligation threshold prior to this IRP filing, the Company anticipates that FERC will rule on the Company's application during this proceeding. Therefore, pursuant to the Commission's directive in Case No. U-20905 *et al.*, the Company has provided rationale as to why a Standard Offer cap of 5 MW is not appropriate. In addition, and in accordance with MCL 460.6v, the Company agrees to publish on its website the Company's proposed template contract for PPAs with QFs greater than 100 kW but less than or equal to 5 MW. QFs that participate in the Company's annual solicitation process will also be provided the Company's template PPA prior to the issuance of the RFP. MCL 460.6v provides that the terms of a template PPA are not binding on either an electric utility or a QF and may be negotiated and altered upon agreement between an electric utility and a QF.

**Q. Does the Company have any additional proposed changes to the Standard Offer?**

A. Yes. The Company proposes to update the basis for capacity compensation for the Standard Offer Contract and Standard Offer Tariff. In Case No. U-18090, the Commission issued an Order on July 31, 2017 that requires the Company to pay for capacity using the methodology implemented by MISO at the time the contract is executed for any QFs up to 2 MW in size. See Case No. U-18090, July 31, 2017 Opinion and Order, pages 25-26. MISO is continuing to pursue changes to its resource adequacy construct that are expected to result in a seasonal, instead of annual, resource adequacy period by Planning Year 2023/2024. Company witness Thomas P. Clark discusses these changes further in his direct testimony. As part of the change, the Company anticipates that the winter capacity accreditation for solar will be substantially reduced compared to the current summer test. Compensating QFs for unusable capacity results in unnecessary costs for the Company and

its customers. Therefore, this preferential treatment for QFs up to 2 MW in size should be rescinded to protect customers from an unnecessary increase in cost.

Since the July 31, 2017 Order in Case No. U-18090, the Company has developed and incorporated a new method of compensating for capacity that equally shares the benefit or harm between the Company and its PPA suppliers for any changes that MISO makes to the capacity construct. This methodology results in the Company receiving the entire capacity accredited to the generator and compensating the supplier for the average between: (i) the MISO methodology established in accordance with the MISO Business Practice Manual ("BPM") at the time the contract is executed; and (ii) the MISO methodology established in accordance with the MISO BPM at the time capacity is accredited to the generator for a resource adequacy planning period. The Company has implemented this methodology into several solar PURPA PPAs and PPAs executed as a result of the IRP competitive solicitation process. For these reasons, the Company proposes to update the Standard Offer Contract and Standard Offer Tariff from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA.

**Q. If the Commission does ultimately find that QFs are eligible to receive the Company's full avoided cost rates outside of the annual solicitation process, what PPA term length does the Company propose for QF PPAs.**

A. As explained above, consistent with FERC Order 872, the Company does not support the awarding of the Company's full avoided cost rates outside of the annual solicitation process.[10] However, if the Commission does ultimately find the QFs are eligible to receive

[10] The Company intends to continue to offer full avoided costs based on the solicitations to QFs up to the Company's must buy obligation that had a PPA for both energy and capacity on January 1, 2019.

the Company's full avoided cost rates outside of the annual solicitation process in a manner consistent with the Company's current PURPA avoided cost construct, the Company proposes that such PPAs should be at a term up to 20 years in duration. As further described later in my testimony, the Company intends to change the term lengths of PPAs solicited in the IRP competitive solicitations. While the Company believes that shorter term PPAs are preferable for the Company and its customers, the Commission's May 31, 2017 Order in Case No. U-18090 ruled that the term length offered for the Company's full avoided cost PURPA PPAs would be up to 20 years. Therefore, without limiting the Company's ability to challenge this term length in future cases, the Company proposes to offer full avoided cost rate PURPA PPAs term lengths up to 20 years.

**Q. What does the Company propose with respect to the Company's currently approved reduced avoided cost rate?**

A. The IRP Settlement Agreement provides for a reduced avoided cost rate structure based on MISO PRA capacity rate and either: (i) a 10-year term based on a forecast of LMPs for the first five years and year six through year 10 of the term will be equal to the price of energy in the fifth year of the LMP forecast; or (ii) actual LMPs for 15 years. This rate structure is currently available to QFs when the Company does not have a capacity need. Given FERC's guidance in FERC Order 872 that a utility's avoided capacity cost is zero if it is competitively soliciting its full capacity needs and additional capacity is not needed, the reduced avoided cost capacity rate (i.e. the MISO PRA capacity rate) should be removed from the reduced avoided cost rate.

**Q. Please address the Commission's direction with respect to the formation of Legally Enforceable Obligations ("LEO") by QFs under PURPA.**

A. In its January 21, 2021 Order in Case No. U-20905 *et al.*, the Commission directed "each utility, as part of its next biennial review application, to provide clear guidance on the criteria it will use to evaluate a QF's commercial viability and financial commitment in determining whether an LEO has been formed, again consistent with FERC and Commission precedent."

**Q. What is the Company's proposed criteria on the formation of LEOs by QFs?**

A. As an initial matter, the Company does not believe that individual utility biennial filings, like this IRP proceeding, are the appropriate forum to consider the formation of LEOs under PURPA because it would unreasonably result in different LEO standards for each Michigan utility. If the Commission desires to adopt specific criteria for the formation of a LEO, the Commission should consider such criteria in a proceeding that involves all Michigan utilities. There should be uniformity in the LEO criteria required of all Michigan utilities so that one or more utilities is not required to utilize a potentially less stringent LEO standard. In DTE Electric Company's recent PURPA avoided cost case in Case No. U-18091, the Commission approved changes to the structure of DTE Electric Company's Standard Offer "in the interest of more uniform QF development across the State." Case No. U-18091, July 31, 2017 Opinion and Order, page 21. The Commission should reach a similar finding with respect to the criteria for LEO formation and find that the criteria for the formation of a LEO should be uniform throughout Michigan.

In addition to the above, and as explained in more detail in the Company's November 30, 2020 Comments submitted in Case No. U-20905 *et al.*, in FERC Order 872,

~~FERC provided minimum guidance for the establishment of a LEO. FERC established new regulations, effective at the end of 2020, "to require QFs to demonstrate that a proposed project is commercially viable and that the QF has a financial commitment to construct the proposed project, pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO." FERC Order 872, pages 373-374. FERC also affirmed that "states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment, albeit subject to the criteria being objective and reasonable." *Id*.~~

~~The Commission should affirm FERC's directive in FERC Order 872 regarding minimum requirements for the establishment of a LEO and also make clear that a QF's meeting of these requirements does not, in and of itself, mean that the QF has formed a LEO. In particular, consistent with comments submitted by Consumers Energy to the Commission in the past, the MPSC should emphasize that a QF must demonstrate that it is commercially viable and has made appropriate financial commitments to demonstrate its viability, before a LEO can be established. In addition to affirming FERC's minimum LEO requirements, the Commission should clarify that, in the process of establishing whether or not a QF project has a LEO, the Commission will continue to assess each QF project on a case-by-case basis to determine if the QF project is a real, viable project on which customers can rely.~~

~~If the Commission desires to establish specific LEO criteria, in the alternative to the current case-by-case approach described above, the Company proposes to use a modified version of the criteria submitted by the Company on May 1, 2020 in the context~~

~~of Staff's LEO Workgroup. Specifically:~~

~~(1) A legally enforceable obligation is established between the qualifying facility and the electric utility when a qualifying facility has:~~

~~(a) Provided an electric utility with documentation demonstrating that, under 18 C.F.R. § 292:~~

~~(i) The facility is a "qualifying facility;" and~~

~~(ii) The facility has been certified as a qualifying facility with or by the Federal Energy Regulatory Commission.~~

~~(b) Provided the electric utility all of the following:~~

~~(i) A description of the location of the project and its proximity to other projects within one (1) mile of the project, which are owned or controlled by the same developer or owner or otherwise affiliated with the qualifying facility,~~

~~(ii) An estimated, non-binding, good faith estimate of the energy production for the project that includes the kilowatt-hours to be produced by the qualifying facility for each month and year of the entire term of the project's anticipated power purchase agreement,~~

~~(iii) An Internal Revenue Service Form W-9,~~

~~(iv) Evidence of an engineering, procurement, and construction program that will result in commercial operation of the project (and the project's interconnection) on a defined schedule that is consistent with the capacity needs of the purchasing utility,~~

~~(v) Evidence of a secured commitment from major equipment manufacturers for the delivery and/or installation of all major equipment to be utilized by the project,~~

~~(vi) Evidence that the project is financeable, and~~

~~(vii) Proof of fuel security, or, if the project is for wind, solar, or hydroelectric generation, the amount of available fuel at the project's location.~~

~~(c) Demonstrated that it has taken meaningful steps to obtain site control adequate to commence construction of the project at the proposed location.~~

~~(d) If qualifying as a "cogeneration facility" under R 460.1052(1)(a) provided the electric utility with written proof of a steam host that is willing to contract for steam over the full term of the project's anticipated power purchase agreement for a cogeneration facility.~~

~~(e) Submitted an interconnection application and completed the process of obtaining any necessary interconnection study results (engineering review and/or distribution system study results) from the Company under R 460.620.~~

~~(f) Agreed, in writing, to pay the system construction or modification costs identified in any interconnection study pursuant~~

~~to R 460.620(10).~~

~~(g) Unilaterally signed and tendered a proposed power purchase agreement ("PPA") to the purchasing utility with a price term equal to either:~~

~~(i) the existing standard offer rate in accordance with the applicable standard tariff provisions as approved by the commission for qualifying facilities eligible for standard offer rates; or~~

~~(ii) a price term consistent with the purchasing utility's avoided costs, with specified beginning and ending dates for delivery of energy, capacity, or both to be purchased by the utility~~

~~The Company's above recommended criteria are generally consistent with Staff's second Strawman Proposal for Interconnection, DG, and LEO standards ("Strawman Proposal") published by Staff on February 28, 2020. However, the Company's proposed additions to Staff's Strawman Proposal are intended to ensure that, at a minimum, the proposed LEO criteria be revised to require: (i) that meaningful steps have been taken to secure site control, consistent with FERC Order 872; (ii) that developers be required to provide evidence of engineering, procurement, and construction agreements associated with each project; and (iii) that developers be required to provide evidence that their project is financeable. These recommendations are based on the Company's actual experience to date, which includes encountering developers with competing "options" to lease the same parcel of land, and significant uncertainty regarding project financing, equipment availability, project construction schedules, and project development progress.~~

~~The Company is also proposing, consistent with the Commission's existing interconnection rules, that QFs be required to obtain any necessary interconnection studies from the Company and then agree, in writing, to pay any system construction or modification costs identified in those studies. These requirements do not place formation of a LEO solely in the hands of the Company because the process and timing for such~~

~~studies is objective, predictable, and governed by Commission rules. In the Company's recent experience, many proposed QF projects have turned out to be non-viable upon receipt of interconnection costs. The only way to ensure that a QF is in fact commercially viable, consistent with FERC Order 872, is to ensure that the QF has obtained interconnection cost estimates under the MPSC-prescribed process and agreed to pay those costs.~~

~~In addition, the Company submits that formation of a LEO requires "a binding commitment by both sides to the agreement or obligation – the obligation by the utility to purchase the power and the obligation by the QF to provide energy and capacity upon which the utility and its customers can rely." See September 26, 2019 Order in MPSC Case No. U-20156, Page 53. Without the additional requirements recommended by Consumers Energy, the Company is concerned that a LEO could be formed without a true commitment by developers. Allowing a LEO to arise without additional evidence of that commitment will not "strike the right balance between access for QFs on the one hand and system reliability and certainty in utility planning and procurement to protect ratepayers on the other hand." See September 26, 2019 Order in MPSC Case No. U-20156, Page 54.~~

~~Furthermore, the Company requests clarification from the Commission as to when a LEO is abrogated. Even after a LEO is formed by a QF, there may be modifications made which materially change the nature, and potential viability, of a proposed project. Since the formation of a LEO hinges on the viability of a project, a formed LEO cannot continue in perpetuity for an undeveloped project. Therefore, clear guidance is needed from the Commission to define when a previously formed LEO has been terminated. For example, a QF that proposes a material modification to its project design, and therefore~~

~~will require new interconnection studies and new interconnection cost estimates, should be required to re-affirm its commitment to paying those costs, that it has taken meaningful steps toward site control for the modified project, and provide evidence that the revised project remains financeable. In the Company's experience, many QF projects languish for years in the Consumers Energy interconnection queue and uncertainty around the potential future plans for such projects can cause significant uncertainty for the Company's resource planning.~~

## SECTION V: COMPETITIVE SOLICITATIONS

### Summary of 2019 and 2020 Competitive Solicitations

**Q. Are you familiar with the Company's competitive solicitation process for IRP supply-side resources?**

A. Yes. In Case No. U-20165, I sponsored direct and rebuttal testimony describing the Company's plans to utilize competitive solicitations to procure PPAs and Company-owned solar resources to meet the IRP Settlement Agreement PCA. I also have management oversight of the administration of competitive solicitations for new generation resources.

**Q. Please provide a summary of the competitive solicitation process from the IRP Settlement Agreement.**

A. In accordance with the IRP Settlement Agreement, the Company uses an annual solicitation process to procure the supply-side technologies specified in the IRP PCA. Each solicitation must meet the following requirements:

1. Administration of the solicitation by an independent evaluator ("IE") (also referred to as "Independent Administrator" in Company's regulatory filings);

2. The Company makes the selection of provisional award from a blind ranking of evaluated proposals as provided by the IE;

3. QFs are permitted to bid any technology into the solicitation;
4. The cost and value of the proposed project are to be considered to determine the net cost as may be modified by value added criteria;

5. The solicitation will follow the 2008 Guidelines for Competitive Request for Proposal of Renewable and Advanced Cleaner Energy from the Commissions December 4, 2008 Order in Case No. U-15800 plus (i) the issuance of public notice to interested parties, and (ii) providing the terms of the contract with the RFP;

6. Respondents may select a PPA term length up to the depreciation schedule of a similar Company asset (i.e. 25 years for solar);

7. 50% will be sourced from PPAs and 50% will be owned by the Company, however the Company can select more than 50% from PPA capacity at its sole discretion; and

8. The Company must inform respondents of the impact of the FCM on PPA proposals.

Additionally, the Company's solicitations will be required to follow any future applicable guidelines for competitive procurement that the Commission may adopt.

**Q. Has the Company gained additional experience and insight on the effectiveness of these solicitation requirements since the approval of the IRP Settlement?**

A. Yes. The Company's, third-party independent administrator, Enel X, issued the first annual solicitation on September 30, 2019 to procure 300 MW of new solar capacity to be installed by 2022. A total of 49 unique proposals covering 34 unique projects and representing nearly 2,000 MW of capacity, were submitted on a confidential basis in the 2019 competitive solicitation. Of those, 24 proposals were offered as a BTA and 25 were offered as long-term PPAs. Fifteen projects that participated were PURPA QFs up to the Company's current must buy obligation of 20 MW.

The Company entered into a 140 MW PPA with Calhoun Solar Energy, LLC and a 150 MW Build-Transfer Agreement ("BTA") with Mustang Mile, LLC for the development and construction of the Mustang Mile project that will be owned and operated by the Company. These agreements were filed in Case No. U-20165 and the PPA and BTA

were both approved by the Commission on April 8, 2021. In accordance with the IRP Settlement Agreement, the Company filed updated PURPA full avoided costs including the Standard Offer Contract and Standard Offer Tariff in Case No. U-20165 on April 14, 2021, which were approved by the Commission's May 26, 2021 Order in that docket. The Company is currently in discussions with QFs to fill the remaining 10 MW of capacity. Enel X has produced a final report on the 2019 IRP solar competitive solicitation which contains more details on the Company's first IRP-based competitive solicitation process. This report is provided as Exhibit A-48 (KGT-4).

On July 29, 2020, Enel X issued the second annual solicitation to procure 300 MW of new solar capacity to be installed by 2023. A total of 43 unique projects representing nearly 2,500 MW of capacity, were submitted on a confidential basis in the 2020 competitive solicitation. Of those, 21 unique projects were offered as a BTA and 19 unique projects were offered as long term PPAs. Five unique projects that participated were PURPA QFs up to the Company's must buy obligation threshold of 20 MW. At the time of the preparation of this filing, the Company has executed one PPA which is expected to be filed for MPSC approval in July 2021 and is in negotiations with developers on several projects to fill the solicited capacity. The Company's IE will be issuing and completing the 500 MW 2021 solicitation for 2024 resources while this case is ongoing.

**Q. What role does the IE have in the solicitations?**

A Enel X, as the IE of the Company's 2019 and 2020 solicitations, supported the Company by assisting in the RFP development, advertising and releasing the RFP, independently and without bias administered fair and transparent solicitations, provided individualistic support to respondents, collected and evaluated proposals, produced blind shortlists, and

provided regulatory support post solicitation. Enel X has also been supporting the Company's continuous improvement efforts to improve the Company's competitive procurement practices.

**Q. What were the criteria used to rank proposals?**

A Proposals were first screened based on factors identified by the Company as necessary to ensure a viable project. These include factors such as minimum and maximum capacity offer, contract length, interconnection status, feasibility location site control and creditworthiness. Per Section 9.2 of the Consumers Energy RFP; Proposals were to be evaluated based on projected costs, projected commodity value, and value-added criteria. The economic evaluation consisted of first calculating the total projected cost of a proposal. Second, the projected value of the commodities provided by the proposed project was subtracted from the total projected cost to calculate a net cost for the proposal. Lastly, the value-added criteria was subtracted from the net cost to determine the final, adjusted net cost of the proposal. Projects were then ranked based on their adjusted net cost. A blind ranking of the proposals was then provided by Enel X to the Company for review and provisional award of projects to move forward with due diligence and negotiation between the Company and the proposal developer.

**Q. What impact did the FCM have on the solicitations?**

A PPAs are subject to the FCM approved as part of the IRP Settlement Agreement in Case No. U-20165. The FCM was included in the economic evaluation of all PPA proposals, and its inclusion in the evaluation did not affect the ranking or impact the outcome of the solicitation results in any way.

**Q. How are the new solar assets represented in this filing?**

A. The details about the size, performance, and costs of the 2019 and 2020 solicitation resources was unknown at the time that input assumptions were finalized for inclusion in the base assumptions for IRP modeling. Therefore, the Company relied on proxy assumptions for this filing including 300 MW in 2023, 300 MW in 2024, and 500 MW in 2025 for base modeling assumptions. Of this capacity, the Company assumed that 50% would be owned by the Company and 50% would come from PPAs. The base modeling assumption for PPAs included in this IRP are detailed in Exhibit A-45 (KGT-1).

**Proposed Changes to Future Competitive Solicitations**

**Q. Is the Company proposing any changes to the annual competitive solicitation process in the IRP Settlement Agreement?**

A. Yes. Based on the Company's experience with the 2019 and 2020 solicitations, there are several improvements that the Company proposes related to the targeted MWs acquired in each solicitation and timing of project Commercial Operation Dates ("COD"); the solicitation ownership structure; the manner in which MWs acquired in each solicitation will be ultimately reconciled, the term length of PPAs, and the evaluation of bids.

**Q. Please explain the Company's proposed changes related to the targeted MWs acquired in each solicitation and timing of project COD.**

A. The Company is challenged to balance the "lumpiness" of achieving a target capacity to the exact MW with resources as large as 150-200 MW in size. Finding the perfect blend of projects to get an exact amount of capacity (e.g. 300 MW) is not a simple or easily repeatable process. Further, the Company must try to achieve exactly 50% PPA and 50% Company-owned in each solicitation further complicating the lumpiness issue. For

example, if the Company has a target of 150 MW and the best evaluated project is 50 MW with the second best evaluated project at 150 MW, the Company may prefer to pursue both projects, or perhaps just the 50 MW, and make up the difference in a future solicitation. However, the current requirement to award any shortfall to PURPA incentivizes the Company to over-procure the Company-owned tranche of the solicitation to prevent missing an opportunity to own and operate half of its supply portfolio. Further, with the 50% PPA and 50% Company-owned ownership structure required in each solicitation under the IRP Settlement Agreement, the Company must similarly over-award on the PPA tranche to match any over-award on the Company-owned tranche. This iterative process creates uncertainty, inefficiency, and additional cost within post-solicitation activities which has resulted in delays and frustration in the negotiation process.

To obtain the best projects for customers, the Company requires additional flexibility to be able to select more or less capacity than the solicited MW target in each annual solicitation. There may be solicitations that result in extremely high-cost proposals that the Company would not want to obligate customers to pay. Similarly, there may be solicitations that result in extremely low-cost proposals that the Company would like to acquire to get the best costs for customers. Therefore, the Company proposes to both (i) remove the requirement that leftover capacity from each solicitation is made available to PURPA QFs, as discussed in the prior section of my direct testimony, and (ii) add flexibility to pursue more or less capacity in any given annual solicitation to more efficiently track towards the long term PCA acquisition targets. With the approval of these proposals, the Company will continue to file the PPAs and Company-owned assets for

Commission approval, which will ensure that the flexibility requested by the Company will be subject to Commission oversight.

Since the flexibility provided to the Company in each solicitation allows the Company to procure more than the targeted MW amount in any given year, the Company will reconcile the total MWs procured in the prior solicitations with the MWs needed to implement the PCA in each subsequent IRP proceeding. In other words, the Company would not reconcile the annually acquired MWs against the targeted PCA MWs between the annual solicitations. The IRP-based reconciliation would also address instances where the Company is required to acquire supply-side capacity outside of the solicitation, like the PURPA Settlement Agreement. Since the Company may ultimately procure more or less than the targeted MW amount, the Company may make upward or downward adjustments to the to-be-acquired MWs in the PCA in future IRP proceedings.

In addition to the above, and as discussed in more detail below, the Company proposes to generally maintain the current ownership structure of the solicitation process, with the caveat that the Company may own at least 50% of the new capacity with the remaining capacity coming from either PPAs or Company-owned resources, based on economics. Because the Company is proposing to acquire potentially more than 50% of new capacity from Company-owned resources, the IRP-based reconciliation would also address instances where the Company decided to acquire Company-owned projects instead of PPAs. The Company would provide the basis for its decisions to pursue Company-owned projects over PPAs in future proceedings seeking approval of the specific Company-owned project.

Furthermore, the Company proposes that the at least 50% Company-owned and 50% either PPA or Company-owned ownership structure be viewed over a longer term, beginning with the IRP Settlement Agreement, and revisited in each IRP, versus annually, due to the lumpiness of utility scale solar as previously discussed. This will allow sufficient flexibility to acquire potentially more or less than the targeted MW amount in each solicitation and account for instances where the Company may be required to take on other supply-side resources. As demonstrated in the table below, the Company is significantly oversupplied with solar PPAs, beyond the originally intended 50% PPA and 50% Company-owned ownership structure established in the IRP Settlement Agreement, due in part to the PURPA Settlement Agreement. Since the IRP Settlement Agreement, the Company has added the following capacity to its supply-side portfolio resulting in only 20% Company ownership and 80% PPA:

| Resource | Ownership | Capacity (MW) | Source |
|---|---|---|---|
| PURPA Solar | PPA | 434 | PURPA Settlement Agreement |
| Calhoun Solar | PPA | 140 | 2019 RFP |
| Mustang Mile | BTA | 150 | 2019 RFP |
| PURPA Solar | PPA | 10 | 2019 RFP |
| **Total** | | **734** | |

Due to events like the PURPA Settlement Agreement, it is more reasonable to meet the Company's proposed ownership structure over the longer-term period described above. Therefore, the Company proposes that the requirement to establish ownership in each solicitation be replaced with a target of maintaining the structure, beginning with the IRP Settlement Agreement, in each subsequent IRP.

The Company also intends to provide additional flexibility on the timing between the annual solicitations and the required COD prescribed in each solicitation. Through the

first two solicitations, one common issue is the proposal's interconnection schedule and required network upgrades misaligning with the COD deadlines of the solicitation. The rigidity of the current three-year cycle is causing uncertainty in the Company's ability to procure the right amount of capacity when needed to meet MISO's Planning Reserve Margin Requirement ("PRMR") since project schedules tend to slip for reason's outside of the Company's or a developer's control. Similarly, the Company has experienced proposals that are "too developed" meaning that the project would result in significant investment before the Commission could review and issue an order on the reasonableness of procuring the asset.

**Q. Please explain the Company's proposed changes related to the ownership structure of the resources selected in the solicitations.**

A. In future solicitations, the Company proposes to acquire *at least* 50% of the capacity from Company-owned resources and 50% from either PPAs or Company-owned resources, based on economics. The Company is proposing this modification to the current solicitation structure, which caps the Company's acquisition of Company-owned resources at 50%, because it has the unintended consequence of restricting the Company's ability to meet its annual solicitation capacity. Projects that are ultimately owned and operated by the Company are not easily scalable and typically are the most economic when constructed as initially designed. However, PPAs are scalable because the supplier can more easily line up several buyers to procure a portion of the output or sell a portion into the MISO market. For example, the Company's 100 MW PPA with River Fork Solar results in the purchase of about 67% of the 149 MW plant's output. Similarly, the Company's 140 MW PPA with Calhoun Solar Energy results in the purchase of about 70% of the 200 MW

plant's output. The Company would expect to see better alignment with the total solicited capacity if the Company were able to own at least 50% and allow the PPAs to be scalable to fill the remaining capacity. Therefore, the Company proposes to own at least 50% of the new solar capacity procured through the IRP.

**Q. How does the Company view the costs and benefits of Company-owned projects compared to long term PPAs?**

A. There are several significant differences between Company-owned projects and long term PPAs for customers including: (i) value; (ii) cost; (iii) risk; and (iv) regulatory oversight. First, for Company-owned projects, customers have an inherent economic optionality built into the facility. Throughout the useful life of the asset, the Company can, through economic analysis under the MPSC's oversight, make additional investments into the facility to extend the plant's useful life, improve the efficiency of plant, or economically retire the plant. This optionality may only be realized in PPAs if contractually included in the PPA as an option to extend, purchase, or terminate. Rather, PPAs are an obligation on behalf of both parties where the supplier can make similar decisions to extend the useful life or improve the efficiency of the plant but is able to retain the value of the economic decision without conveying it to the Company or our customers. Typically, the Company's PPAs include early termination security provisions that require a financial obligation for either party to terminate the PPA. In the case that a supplier terminates the PPA, the Company would receive a financial payment, but would still need to contract with, purchase from the wholesale market, or build replacement capacity and energy to fill the void in supply created by such termination.

Second, the costs of Company-owned facilities are typically front loaded in capital investment with some amount of ongoing Operating and Maintenance ("O&M") expense, both of which are subject to recovery through regulatory approval in each electric rate case. The reasonableness of expense(s), whether capital or O&M, are constantly reviewed through the life of the asset. However, PPAs are typically subject to review and approval of the PPA at a single point in time before the PPA begins. Then, once approved and effective, the PPA rates are locked in for the life of the asset. The ability for the Company to challenge decisions made by a supplier are limited to the performance and availability guarantees built into the contract from the start. For this reason, the Company, and ultimately its customers, experience misalignment between PPAs and the wholesale market as market conditions tend to change over the term of a PPA. When PPA rates exceed market costs, the Company's customers take on the additional cost, and when PPA rates are lower than market costs, the Company's customers realize the cost savings, both of which occur through the PSCR mechanism. Historically, the Company's PPA rates have exceeded actual wholesale market costs even though the costs could be based on wholesale market forecasts.

Third, there is a significant difference in both the oversight by the MPSC, as well as commitments to the communities in which facilities are located. PPA oversight, once approved, is generally limited to ensuring that the terms of a PPA are met. The MPSC does not typically have the authority to question PPA supplier decision-making. Whereas, the Company engages with the MPSC in numerous filings annually, where the MPSC has the authority to challenge the Company's decisions and ultimately determine whether or not the costs incurred will be recoverable from customers. The Company owns and

operates generation and has retail customers throughout the lower peninsula of Michigan. The Company has an obligation to care for the communities in which it serves gas and electric customers. PPA suppliers, especially when set up as LLCs, do not have the same responsibilities to care for customer's communities.

**Q. Please explain the Company's proposed changes related to the PPA term sought in each solicitation.**

A. Currently, in accordance with the competitive solicitation process approved in the IRP Settlement Agreement, the Company solicits PPA terms lengths up to 25 years in its annual solicitations. While the Company recognizes that the PPA term lengths that it solicits is ultimately a management decision, going forward, the Company intends to solicit PPAs which are a maximum of 15 years in length. The Company will also solicit PPAs which provide for an option to purchase or extend the PPA term beginning in the 10th year of the PPA and continuing in five-year increments thereafter.

**Q. Why is the Company interested in pursuing options to purchase PPA facilities or extend the term of the PPA?**

A. There are significant differences in the value provided for customers from Company-owned facilities versus PPAs. As previously discussed, Company-owned facilities include inherent optionality for customers to maximize the value of the facility by economically improving, extending, or retiring a generating asset. Historically, the Company has partially addressed this value by including a terminal value in the economic analysis of Company-owned facilities. However, terminal value as implemented by the Company only reflects the option to extend, not the options available to customers for the Company to improve or extend the life of an asset. In an effort to obtain a more apples-to-apples

comparison in value provided by Company-owned assets and PPAs, the Company can build the optionality into the PPAs through an option to purchase or extend the PPA at a specific time during the PPA term. Based on recent research into renewable PPA terms and competitive procurement, the Company anticipates that shortening the PPA term and including options that the Company may enforce during the PPA term will result in financeable PPAs for the developer while increasing value to our customers.

**Q. Has the Company commissioned any independent analysis to support its position on PPA term length?**

A. Yes. The Company was aware that non-utility corporations had been able to procure a variety of renewable PPAs to meet renewable or sustainability initiatives. The Company hired Wood Mackenzie ("WoodMac") to conduct research into the competitive procurement and renewable PPA strategies conducted throughout the utility and non-utility sector to determine if there are additional best practices that the Company could adopt to improve the acquisition of renewable technologies for our customers.

**Q. Please explain Exhibit A-46 (KGT-2).**

A. Exhibit A-46 (KGT-2) is a final, independent report that WoodMac created to summarize its findings of the research requested by the Company on renewable PPA strategy and competitive procurement. The first topic summarized in the report on pages 4 through 14 of the Exhibit is a comparison of traditional utility PPA structures to those utilized by the Commercial and Industrial ("C&I") customer segment. The second topic summarized in the report on pages 15 through 20 is a comparison of the Company's PPA procurement strategy to the processes utilized by C&I customers. In both sections, WoodMac has

included a review of risks, opportunities, and/or evaluation of the Company's current practices compared to C&I customers.

**Q. Based on the research conducted by WoodMac, what additional changes does the Company propose to make to its competitive procurement process?**

A. With respect to PPAs, the Company intends to procure PPAs with a maximum term of 15 years as previously discussed. The C&I customer segment is successfully balancing buyer flexibility with developer certainty with contract terms in the 12 to 15-year timeframe. This shorter initial period will help ensure that the Company's customers are not saddled with higher PPA prices in the later years of a PPA. Additionally, the Company intends to include the option to extend or option to purchase in future PPAs that it acquires through the competitive solicitation process to increase the value of the PPA for customers. The combination of shorter term PPA with these options is expected to result in better PPAs for our customers.

The WoodMac report identifies several additional opportunities or risks for the Company to consider including: (i) the potential for negative market prices; (ii) diversification of production risk; (iii) the evaluation of bundled and unbundled environmental attributes; (iv) wholesale price separation between the project and the Company's load; and (v) inclusion of the Right of First Refusal to purchase at the end of a PPA. Some of these topics can be incorporated into the solicitations under the current IRP Settlement Agreement as they are not material to the solicitation process, but rather, the specific terms of the PPA offered through the solicitation. The Company will consider WoodMac's suggestions in the upcoming solicitations.

With respect to the competitive procurement process, there are changes that the Company is seeking in this IRP including: (i) flexibility on COD dates; and (ii) laddering procurement. First, the Company has experienced delays in both transmission and distribution connected projects, leading to a lower probability of meeting the Company's PRMR in years when the Company's surplus capacity is small. The Company and its customers are expected to have a greater certainty of procuring an adequate amount of resources through the "laddered approach" suggested by WoodMac. The Company would intend to procure in a single solicitation, capacity from resources with a variety of start dates from approximately 3-5 years from the solicitation. This flexibility in procurement will provide more certainty for resource planning by acquiring resources further in advance of COD, and for PPAs, with a variety of contract term lengths to limit the amount of capacity leaving the Company's supply in a single year at the end of the PPA(s) term.

Regarding the competitive procurement section in the WoodMac report, there are also several additional opportunities or risks for the Company to consider including: (i) technology limitation; (ii) geographic limitation; and (iii) flexibility to understand pricing. Some of these topics including technology and location are applicable for other types of Company solicitations, including VGP solicitations or bilateral capacity auctions where the technology or MISO Local Resource Zone ("LRZ") are not prescribed like it is in the IRP. There are some topics that can be incorporated into the solicitations under the current IRP Settlement Agreement through the use of multiple tranches or eligible bidding options that the Company can further purse in the upcoming solicitations.

**Q. Please explain the Company's proposed changes to the evaluation of bids in the solicitation process.**

A. The Company intends to increase the flexibility for how to conduct and update its evaluation process from the rigidity specified in the IRP Settlement Agreement. The Company agrees with the general construct that the cost of a resource and the value provided (including non-commodity value) are important to economic considerations of resource. Additionally, there are mitigation attributes of a proposal that are important to consider in each solicitation. The objective of a competitive solicitation to drive down costs while maximizing value is best accomplished through continuous improvement based on lessons learned and experience. Therefore, the Company intends to remove two prescribed elements from the evaluation process, including (i) ranking proposals on a net cost basis, and (ii) establishing Value-Added Criteria on a $/MWh as used in the 2019-2021 solicitations. First, the net cost concept does not appropriately scale with the changes in cost and value if the two factors move substantially. There are other metrics that should be considered such as cost to value ratios. For example, if Proposal A has a cost of $95/MWh and a value of $100/MWh, the net cost (value) is ($5)/MWh; and if Proposal B has a cost of $45 and a value of $50/MWh, the net cost (value) is ($5)/MWh. However, if the value is based on a volatile commodity, the lower risk project is likely Proposal B since Proposal A relies on a higher estimated value. Using this example, Proposal A would have a cost to value ratio of 95% and Proposal B would have a cost to value ratio of 90% which means that Proposal B is the preferred project using the cost-to-value ratio methodology. An alternative perspective using cost to value ratios is that the reciprocal of the ratio illustrates how much value is received for each dollar spent. For Proposal A for each dollar

spent, customers would receive $1.05 in value and for Proposal B for each dollar spent customers would receive $1.11 in value.

Second, in the 2019 through 2021 solicitations the Company established all non-pricing factors as Value Added Criteria on a $/MWh basis which was more divisive than traditional points-based evaluations for unique properties of a proposal. Similarly, to address some of the qualitative aspects of a project including development progress and project risk, the Company increased the screening criteria for eligible proposals. As the Company is seeking more flexibility on the timing of CODs in each proposal, it is unlikely that a robust screening criterion will be flexible enough to handle the variety of developmental status that will be bid into the solicitation. The Company supports transparency in the solicitation process for respondents to understand how proposals will be evaluated, but this transparency must be balanced with the Company's ability to improve the evaluation process through the flexibility to adopt best practices from the utility and C&I procurement processes.

**Q. Are there any other changes or clarifications related to the Company's competitive solicitation process?**

A. Yes. While the Company intends to meet its full supply-side capacity needs with the annual competitive solicitation process, the Company also requires opportunities for learning and development. To that end, the Company intends to pursue supply-side resource pilots outside of the competitive solicitation process. These pilots will allow the Company to better understand how emerging technologies fit within the Company's resource portfolio and how those emerging technologies may be better considered in a future IRP. The purpose of these pilots is not to secure capacity, displace PCA capacity acquisitions, or

otherwise to meet the Company's capacity needs. Rather, any projects pursued through the pilot process would be intended to expand the Company's knowledge and experience for unique, novel projects. If the Company ultimately pursues a specific supply-side resource pilot, and seeks cost recovery, the Company will present that pilot in a future rate case, similar to the battery pilots presented in the Company's 2020 electric rate case, Case No. U-20697.

**Q. Are there other situations in which the Company may need to acquire capacity?**

A. Yes. It is possible that the Company could be faced with a short-term capacity need due to an unforeseen change in its generation portfolio or resource acquisition plan. One such circumstance, as previously discussed in my testimony, could be due to the slippage in the schedules of both PURPA and IRP solar resources that are relied on as part of the Company's long-term capacity planning. Another circumstance could be the catastrophic outage of an existing capacity resource. Under these circumstances, the Company could be in a position in future Planning Years where its capacity supply will not meet its MISO PRMR on a short-term basis. In that situation, the Company cannot use the annual solicitation process to fill that need due to the time required to potentially build a new resource. If the Company determines that a significant shortfall of capacity is needed for an upcoming Planning Year, the Company would issue a separate capacity solicitation, such as the Company's prior reverse auctions for capacity, to reduce cost risk for customers as it has done in the past. The Company needs flexibility to make such short-term capacity purchases in order to address emergent, unplanned capacity shortages and to protect customers from the potentially significant costs associated with falling short of MISO PRMR requirements.

**Q. If the proposed changes to the solicitation process are adopted, will there be opportunities available to QFs?**

A. Yes. As described above, the Company intends to allow QFs of any technology to continue to bid into its competitive solicitations. As previously described, the Company has expanded its DG program for QFs up to 150 kW in size that meet certain program requirements. Further, QFs can pursue a PPA under the reduced avoided cost rates, as previously described. Lastly, the Company anticipates that wholesale market participation for QFs 100 kW and up will become readily available through the MISO market as a result of FERC Order 2222.

**Q. How does the Company intend to seek approval of the projects selected in the competitive solicitation process?**

A. Subsequent to the completion of the Company's 2019 competitive solicitation, the Company filed the selected PPA, BTA, and the avoided cost rates stemming from the 2019 competitive solicitation for *ex parte* approval in the 2018 IRP docket, Case No. U-20165. In the Commission's Orders issued on April 8, 2021 and May 26, 2021 in Case No. U-20165, the Commission approved the Company's filings. Based on the process established in Case No. U-20165, the Company proposes to continue filing the PPAs, Company-owned projects, and avoided cost rates for *ex parte* approval in the docket of the most recently approved IRP.

The above expedited approval process is beneficial to both the Company and the counterparties to PPAs and Company-owned projects because it provides assurance that the Commission deems the selection of those projects to be reasonable. With respect to Company-owned projects like BTAs, it is typical that milestone payments begin shortly

after execution. This means that the parties are required to begin performing under a contract prior to the time that rate approval can be provided in a rate case, Certificate of Necessity proceeding, or subsequent IRP proceeding. The expedited approval process is also beneficial from a PURPA perspective because it will result in the timely approval of full avoided cost rates stemming from each solicitation. If lengthy proceedings are required for the approval of the resources selected in each competitive solicitation, it is possible that the proceedings for different competitive solicitations will overlap making it unclear which full avoided cost rates applies to certain periods of time.

In support of the request for *ex parte* approval of the resources selected in the competitive solicitation process, the Company will show that the selected resources are consistent with or below the modeled cost of that resource in the Company's most recently approved IRP. Furthermore, the Company will request rate recovery of the projects which will be owned by the Company in the next electric rate case filed after execution of the agreement for the Company owned resource.

## SECTION VI: 2021 NATURAL GAS PLANT RFP

**Q. Did the Company conduct a competitive solicitation for supply-side resources in addition to the solar solicitations discussed above?**

A. Yes. The IRP Settlement Agreement required the Company to conduct a retirement analysis of J.H. Campbell ("Campbell") Units 1 and 2 in this IRP filing. This requirement caused the Company to evaluate the potential accelerated retirement of Campbell Units 1, 2, and 3 and the Company also considered the accelerated retirement of D.E. Karn ("Karn") Units 3 and 4 as detailed by Company witness Richard T. Blumenstock. Therefore, the

Company decided to conduct a competitive solicitation in early 2021 for existing natural gas fueled generation.

A significant amount of existing generation capacity would be necessary to accomplish an early retirement of Campbell Units 1, 2, and 3 and Karn Units 3 and 4. The Company determined that 22 gas plants from 10 different owners would meet proposed eligibility criteria and therefore qualify to participate representing 6,269 MW of eligible installed capacity. Company witness Blumenstock further explains the clear advantages in acquiring existing gas resources to support the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3.

**Q. Please provide an overview of the 2021 Natural Gas Plant RFP.**

A. In order to ensure effective oversight and administration of the RFP, consistent with the solicitation guidelines set out by the FERC, described in more detail below, the Company retained an RFP Manager, CRA, as an independent third-party to design the solicitation, administer bidding, and evaluate bids prior to selection. On January 6, 2021, CRA issued an RFP to satisfy potential capacity and energy needs by acquiring up to 2,000 MW of unforced capacity ("UCAP")[11] between April 2023 and April 2026. In order to be considered in this RFP, generators were required to be existing natural gas-fueled combined cycle or combustion turbines located or transferrable to the MISO Local Resource Zone 7 ("LRZ-7), with facilities sized between 50 and 1,400 MW (UCAP). CRA developed and scheduled the publication of a Consumers Energy RFP advertisement, which was run on January 8, 2021 within a daily issue of the S&P Global Platts Megawatt Daily publication. CRA proactively reached out to the 10 different owners with expected eligible generators

[11] UCAP represents the percentage of a generating unit's installed capacity ("ICAP") deemed available after the unit's forced outage rate is taken into account.

and the parties that have participated in other solicitations administered by CRA. CRA conducted a pre-bid informational session on January 14, 2021 with prospective bidders.

**Q. Please explain CRA's role in the 2021 competitive solicitation.**

A. CRA, as the RFP Manager for the Company's 2021 competitive solicitation, supported the Company through RFP development, administered a fair and transparent solicitation independently and without bias, provided support to respondents, collected and evaluated proposals, and produced a recommendation on assets to advance for further due diligence.

**Q. Please provide a participation summary for the 2021 competitive solicitation.**

A. Five potential bidders submitted pre-qualification applications. All bidders offering facilities that met the stated qualification requirements for the RFP were prequalified. Three of the five applicants were not approved for participation. Non-qualifiers included one participant offering a facility or facilities that did not meet the requirement that projects be in service and operational as of the issuance date of the RFP. Others offered resources that did not meet the location requirement, as the facilities did not currently qualify as MISO LRZ-7 and were not capable of reclassifying as a LRZ-7 resource. The two prequalified entities submitted eligible bids encompassing a total of four generation facilities. Bids included two combined cycle facilities and two combustion turbine facilities. In total, the facilities bid into the RFP had approximately 2,000 MW of UCAP.

**Q. Please explain the activities performed by CRA on the proposals submitted in the 2021 Natural Gas Plant RFP.**

A. After the proposals were received, CRA as the RFP Manager:

1. Reviewed all proposals and screened the responses to ensure they conformed with all response requirements;
2. Conducted follow-up conference calls with representatives of each company submitting a conforming proposal to clarify asset-specific issues with the

information provided;

3. Evaluated all conforming proposals according to the pre-specified criteria as outlined in the RFP documents;

4. Managed bidder communication and outreach; and

5. Confirmed the winning proposals and the short list of assets to include for recommendation for advancement by the Company to the definitive agreement phase of the RFP.

**Q. Please explain how proposals were evaluated in the 2021 Natural Gas Plant RFP.**

A. CRA reviewed all proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. Generating assets offered into the RFP were evaluated based on:

1. Estimated Net Present Value ("NPV") for the project over a 25-year period;

2. Asset age and reliability; and

3. Asset-specific benefits and risk factors.

**Q. Please explain the selections of proposals in the 2021 Natural Gas Plant RFP.**

A. On March 12, 2021 the Company received a recommendation from CRA on assets to advance for further due diligence by the Company. The Company followed CRA's recommendation, which resulted in the selection of the 1058 MW UCAP Covert Generating Facility ("Covert Plant") (proposal 1), and the combination of the Dearborn Industrial Generation ("DIG Plant"), Kalamazoo River Generating Station ("Kalamazoo Plant"), and the Livingston Generating Station ("Livingston Plant"), totaling 927 MW UCAP (proposal 2). Proposal 2 was submitted by Company affiliate, CMS Enterprises Company ("CMS Enterprises"). Upon selection of the recommendation from CRA, the proposals were transferred to the Company's Generation Transformation organization for due diligence and negotiation of Purchase and Sale Agreements ("PSA") with the

counterparties. Further discussion about the selected resources is included in Company witness Jeffrey E. Battaglia's direct testimony.

**Q. Please explain the role of your organization and that of Company witness Battaglia in the 2021 Natural Gas Plant RFP.**

A. My team is responsible for pre-solicitation activities, any Company interactions with CRA, and the selection of proposals. After a proposal for a facility is selected, my team engages Company witness Battaglia's organization who then leads the due diligence and negotiation of the PSA. My team continues to support Mr. Battaglia's organization through its processes and serves as the liaison with CRA as needed.

**Q. Other than approval by the Commission, will the acquisitions contemplated in the 2021 Natural Gas Plant RFP require prior authorization from a specific regulatory authority?**

A. Yes. The acquisition of generating facilities such as those to be acquired through the 2021 Natural Gas Plant RFP require prior authorization from FERC pursuant to Section 203 of the Federal Power Act ("FPA") and enabling FERC regulations.

**Q. How will the Company obtain FERC authorization for the purchase of these plants, which include Company affiliated generation?**

A. Section 203 of the FPA provides that FERC will approve an application if FERC finds that the transaction is in the public interest and will not result in cross-subsidization of a non-utility affiliate. The Company will submit one application for each of the transactions contemplated under proposal 1 and proposal 2 to request prior FERC authorization under Section 203 of the FPA. Prior authorization will be required both for the purchase of Covert and the purchase of the generating units owned by subsidiaries of CMS Enterprises.

The Company desired that the RFP be open to all interested parties to increase competition by increasing the number of eligible facilities, including both affiliates and non-affiliates. In addition, since CMS Enterprises, the successful bidder for proposal 2, is a Company affiliate, obtaining FERC authorization for the purchase of the CMS Enterprises' assets (the DIG Plant, Kalamazoo Plant, and Livingston Plant) will require the Company to demonstrate that the transaction is not the result of discriminatory treatment in favor of these affiliates over unaffiliated generators, and that the Company's purchase from a non-rate regulated affiliate will not result in cross-subsidization of the affiliate by the Company. The 2021 Gas Plant RFP was designed to demonstrate both the lack of discriminatory treatment and absence of cross-subsidization in the event an affiliate was a winning bidder.

**Q. Please explain the Company's decision to allow affiliates to participate in the 2021 Gas Plant RFP.**

A. The Company desired that the RFP be open to all interested parties to increase competition by increasing the number of eligible facilities, which included facilities owned by both affiliates and non-affiliates. The use of the RFP structure described below allowed the Company to broaden the pool of potential bidders while addressing the affiliate-specific concerns noted above.

**Q. How does FERC evaluate an affiliate transaction under Section 203 of the FPA?**

A. In Section 203 applications that involve the acquisition of an affiliate's assets, FERC applies what are known as the "*Edgar* standards" to ensure that the franchised utility does not favor affiliates over non-affiliates. FERC provides for three ways to demonstrate lack of affiliate abuse under the *Edgar*[12] standards: (1) evidence of direct head-to-head

[12] *Bos. Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 (1991) ("Edgar").

competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process; (2) evidence of the prices which non-affiliated buyers were willing to pay; and (3) "benchmark" evidence of the prices, terms and conditions of sales made by nonaffiliated sellers. However, FERC has found that, " [i]n the context of an acquisition of affiliated generation, a competitive solicitation is the most direct and reliable way to ensure no affiliate preference."[13] In addition to demonstrating that an affiliate transaction has not inappropriately favored an affiliate, FERC has found that a competitive solicitation may satisfy the Section 203 requirement that a transaction may not have the effect of subsidizing a non-rate regulated affiliate at the expense of a public utility.[14]

**Q. How does FERC evaluate competitive solicitations in the context of affiliate transactions under Section 203?**

A. Where a competitive solicitation is used, FERC uses the solicitation guidelines established in *Allegheny Energy Generating Co.*[15] to determine if the competitive solicitation process satisfies the *Edgar* standards. The *Allegheny* solicitation guidelines have four principles:

1. Transparency: the competitive solicitation process should be open and fair;
2. Definition: the product or products sought through the competitive solicitation should be precisely defined;
3. Evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders; and
4. Oversight: an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.

[13] *Ameren Energy Generating Co.*, 108 FERC 61.081 at P 67 (2004) ("Ameren").
[14] *See Ohio Power Co.*, 143 FERC ¶ 61,075 at P 29 (2013) (providing that Section 203 applicants may satisfy the cross-subsidization requirements by making an *Ameren* showing).
[15] 108 FERC ¶ 61,082 (2004) ("*Allegheny*").

FERC has recently stated that "[t]he underlying principle when evaluating a competitive solicitation process under the *Edgar[/Allegheny*] criteria is that no affiliate should receive undue preference during any stage of the process."[16] As described in Exhibit A-49 (KGT-5), the CRA Recommendation Letter, the 2021 Gas Plant RFP met the *Allegheny* solicitation guidelines and ensured that no affiliate received any undue preference in that solicitation process. In particular, (i) the "Transparency" principle was satisfied because CRA released the RFP and all relevant information about it to all potential bidders at the same time, (ii) the "Definition" principle was satisfied because the RFP clearly stated all relevant aspects of the product sought, (iii) the "Evaluation" principle was satisfied because the RFP clearly specified the price and non-price criteria under which the bids were evaluated, and (iv) the "Oversight" principle was satisfied because the third party that was employed in the design, administration, and evaluation stages of the RFP process has no financial interest in any of the potential bidders, including CMS Enterprises, or in the outcome of the process and does not own or operate facilities that participate in MISO, the market affected by the RFP.

As required by Section 203 of the FPA, FERC authorization for the transaction will be obtained prior to the closing of the transaction. The Company worked with CRA to ensure that the competitive solicitation would satisfy these guidelines and ultimately comply with FERC's *Edgar/Allegheny* standards. FERC's *Edgar/Allegheny* standards, like the MPSC's Code of Conduct Rules, are intended to ensure that a utility does not harm customers through the utilization of affiliate transactions. Therefore, FERC's approval of the Company's purchase of the affiliate CMS plants will be predicated upon, and will

[16] *See Northern Indiana Pub. Service Co., et al.*, 169 FERC ¶ 61,201 at P 15 (2019).

demonstrate, FERC's conclusion that the transaction "will not harm competition or otherwise be inconsistent with the public interest."

**Q. Did participation of the Company's affiliate in the solicitation harm the competitive market?**

A. No. The participation of CMS Enterprises did not affect competition in the MISO market, the State of Michigan, or the 2021 Natural Gas Plant RFP. First, the CMS Enterprises' facilities are currently participating in the MISO wholesale electric and capacity markets. The change in ownership from CMS Enterprises to the Company will not have a material effect on the operation or offers of the units into the market as such participation is governed by the MISO Tariff regardless of ownership. Second, the participation of CMS Enterprises in the solicitation will not have an effect on competition in the state of Michigan. CMS Enterprises is a merchant plant operator in the State and does not have a direct relationship with the Company's retail customers. Third, the participation of CMS Enterprises did not cause harm to, and actually increased competition in, the 2021 Natural Gas Plant RFP. The 2021 Natural Gas Plant RFP sought up to 2000 MW UCAP of natural gas plant capacity. As previously explained in my direct testimony, 22 gas plants from 10 different owners were eligible to participate in the RFP, and an RFP advertisement ran in S&P Global Platts Megawatt Daily publication to provide notice of the solicitation. Additionally, CRA proactively reached out to the 10 different owners with expected eligible generators. Every effort was taken to increase participation by eligible bidders in the RFP.

**Q. Was the CMS Enterprises' bid in the 2021 Natural Gas Plant RFP competitive?**

A. Yes. CRA, the independent RFP Manager, recommended selection of the CMS

Enterprises' bid by Consumers Energy. The CMS Enterprises' bid met the pre-determined qualifying criteria. The project's 25-year NPV, the assets' ages and reliability, and the specific benefits and risks associated with these assets make the proposal 2 bid competitive. The recommendation from CRA was to move forward with both the Covert Plant proposal and the CMS Enterprises proposal based on the evaluation criteria established before proposals were submitted. In fact, the CMS Enterprises' proposal is approximately 30% less expensive on a UCAP basis and 26% less expensive on an ICAP basis compared to the bid by the unaffiliated Covert Plant that was also selected based on CRA's recommendation. As further described in my testimony below, the *total* capital cost of the CMS Enterprises' proposal was also determined to be less than the Company's current embedded *capacity* cost.

**Q. The Commission's Code of Conduct Rules require notification of an impending sale of an asset with a market value of $1,000,000 or more between an affiliate and the utility. Has the Commission been notified of the impending sale?**

A. Yes. A letter was provided to the director of the regulated energy division of the Commission advising of the impending sale on June 24 , 2021.

**Q. Does this purchase comply with the Commission's Code of Conduct requirements involving affiliate asset transfers?**

A. Yes. The MPSC's Code of Conduct Rules, Mich Admin Code R 460.10108(4) provide in part that:

> Asset transfers from a utility to an affiliate or other entity within the corporate structure for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8), is at the higher of cost or fair market value. Asset transfers from an affiliate or other entity within the corporate structure to a utility for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8) is

at the lower of cost or fair market value.

The purchase price for the Company's acquisition of the generating plant assets from CMS Enterprises reflects a fair market price for the assets and is lower than the Company's embedded cost of capacity. See Exhibit A-47 (KGT-3). The sale of the CMS Enterprises' generating assets to the Company is not simply a transfer of assets through a standalone negotiation (at a price determined solely by the affiliated entities). Rather, as described above, this transaction was part of the Company's 2021 Natural Gas Plant RFP that was administered by CRA in a competitive and arms-length environment. The use of CRA allowed for and was designed to ensure an independent, fair, and transparent solicitation. It is under this process that CMS Enterprises proposal was selected as an economical and fair market bid. The contract price is lower than the Company's costs, further demonstrating that the transaction is at a fair market price, and at a price that is beneficial to consumers. The Company's proposed purchase therefore complies with the MPSC Code of Conduct.

**Q. In determining cost under the Affiliate Transfer provision of the Code of Conduct, is the use of the Company's embedded cost of capacity appropriate?**

A. Yes. Utilization of the Company's embedded cost of capacity as cost under the affiliate transfer rule assures that a transaction with an affiliate does not adversely affect the utility's cost structure by causing the cost per unit of service, product, or property to rise above its average or fully embedded cost. In this transaction, the Company is acquiring affiliate-owned resources for the purpose of capacity and the associated energy. Accordingly, to determine if the capacity acquisition is expected to have an impact to customers in the future, the Company must determine what the current cost of capacity is to the customers. The Code of Conduct's comparison of cost to fair market value is to prevent the utility's

customers from subsidizing the utility's affiliate. As such, the use of the Company's embedded capacity cost is appropriate.

**Q. How did the Company determine its embedded costs of capacity?**

A. Exhibit A-47 (KGT-3) provides a detailed calculation of the Company's embedded costs using the costs presented in the Company's most recently approved electric rate case, Case No. U-20697. Total Capacity Related Cost shown on line 1 is the total used in the State Reliability Mechanism calculation presented in that case. The Bundled Test Year Max Demand of 7,052 MW shown on line 2 is sourced from the load forecast that was utilized for Case No. U-20697. Projected Sales and System Output shown on lines 3 and 4, respectively, are also presented in Case No. U-20697. The exhibit shows either the source or formula for each line used to calculate Consumers Energy's embedded capacity cost of $248,951/MW-year that is shown on line 7.

**Q. Please provide support that this transaction is at the lower of Consumers Energy's cost or fair market value?**

A. Exhibit A-47 (KGT-3) compares the Company's embedded capacity cost to the CMS Enterprises' bid selected. As shown in the Exhibit, the CMS Enterprises' bid price shown on line 10 was lower than the Company's fully allocated embedded cost shown on line 7. Therefore, the fair market value of the assets to be acquired, as determined by the independent RFP and represented by the CMS Enterprises' bid price, is lower than the Company's costs and should be used to determine the approved contract price.

**Q. In the alternative, would it be reasonable and appropriate for the Commission to grant a waiver of the Code of Conduct requirements?**

A. Yes. In accordance with Mich Admin Code R 460.10111(3), the Commission may grant a waiver of one or more of the Code of Conduct Rules if the granting of the waiver will not impact the development or functioning of the competitive market. The granting of this waiver will not impair the development or functioning of the competitive market as the Company's actions were appropriate because the purchase agreement for the acquisition of the CMS Enterprises' generating assets was made pursuant to a market-based RFP conducted by an independent third party. The contract between the Company and its affiliate resulted from an arms-length negotiation which followed the independently administered RFP selection process. There was no preferential treatment afforded to the affiliate. Customers benefit from the participation of the Company's affiliate in the RFP, and the potential harm which the Code of Conduct was intended to prevent is not present. Additionally, approving the Company's purchase agreement for the acquisition of the affiliate assets would be consistent with the Commission's approvals for Consumers Energy's power purchases from an affiliate granted in the January 27, 2015 Order in Case No. U-17725 and the January 12, 2017 Order in Case No. U-18194 as well as the Commission's approval of DTE Electric Company's acquisition of the East China power plant from that utility's affiliate in the December 11, 2015 Order in Case No. U-17767, page 23.

**Q. Was CMS Enterprises afforded preferential treatment as part of the auction process or during the contract negotiation?**

A. No. CRA served as an independent third party to administer the 2021 Natural Gas Plant

RFP, which resulted in an arms-length transaction and ensured that there was no preferential treatment or improper information sharing afforded to an affiliate. Participation of affiliates increased the supply available, which led to a greater amount of participation by owners of eligible capacity, thereby increasing competition and benefiting customers. By conducting the 2021 Natural Gas Plant RFP in this manner, the Company satisfies the requirements and the purpose of the Commission's Code of Conduct. In addition, the Company complied with all other aspects of the Code of Conduct in the course of the RFP as well as in negotiating the purchase contract with CMS Enterprises, including the Code of Conduct requirements concerning information sharing, subsidization, and preferential treatment. Consumers Energy did not share any information with CMS Enterprises about the RFP, which was not also provided to other potential bidders, the Company did not and does not subsidize CMS Enterprises and its affiliates, and the Company afforded CMS Enterprises no preferential treatment. The Company's arms-length negotiations with CMS Enterprises resulted in a purchase agreement which is fair, market-based, will benefit customers, and does not negatively affect the market.

**Q. Are there other cost recovery considerations for the gas plants that the Company is seeking approval of in this filing?**

A. Yes. All of the facilities selected through the 2021 Natural Gas Plant RFP are currently operated by Independent Power Producers ("IPPs"). Accordingly, in the normal course of business, IPPs enter into various forward transactions with buyers for commodities available from the facilities. The bid proposal provided by CMS Enterprises for the DIG, Kalamazoo, and Livingston plants reflected existing commodity sales contracts associated with those plants. These commodities include capacity, energy, and steam. As explained

by Company witness Battaglia, the 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. After the acquisition of the DIG, Kalamazoo, and Livingston plants, Consumers Energy will be obligated 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. The purchase agreement for the acquisition of the DIG, Kalamazoo, and Livingston plants includes minimum capacity amounts required to be available for Consumers Energy at and after closing, and the acquisition purchase price appropriately reflects the third-party contractual commitments described above.

**Q. Did the evaluation of the bid including the DIG, Kalamazoo, and Livingston plants include consideration of the commodity sales contracts?**

A. Yes. The evaluation of CMS Enterprises' bid proposal took into account the commodity sales contracts attributable to the DIG, Kalamazoo, and Livingston plants. Therefore, the purchase price of the plants appropriately reflects the commodity contracts and the value that those contracts hold.

**Q. Will Consumers Energy's bundled customers benefit from the Company's assumption of the commodity sales contracts associated with the DIG, Kalamazoo, and Livingston plants after the approval of the Company's acquisition of the gas plants?**

A. Yes. First, as noted above, the purchase price of the plants appropriately reflects the commodity contracts and the value of those contracts. Second, as also noted above, the

Company will recognize the revenue associated with the contracts and use that revenue to offset customer costs. In evaluating CMS Enterprises' bid, CRA modeled the revenue from the forward commodity sales contracts as an offset to the expense of the facility for the NPV analysis. Similarly, the Company has incorporated the future revenues from the forward commodity sales contracts in the IRP evaluation as a credit to general rates. If an opportunity exists to modify or terminate the forward commodity sales contracts that would result in a benefit to customers, the Company will attempt to make such modification or termination.

**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 would assume, the Company is proposing 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 is proposing to 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 does not currently engage in the sale of steam to a host facility. 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.

## SECTION VII: CONCLUSION

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

A. In this direct testimony, I have: (i) provided an overview of the key input assumptions in this IRP related to the Company's existing and anticipated PPAs; (ii) provided an overview of the Staff's DG Program proposal and discussed the Company's consideration of that proposal; (iii) detailed the proposed changes to the Company's FCM; (iv) provided an overview of the Company's implementation of PURPA avoided costs and detailed the proposed changes to the Company's PURPA avoided cost implementation; (v) provided an overview of the Company's IRP-based competitive solicitations and detailed the proposed changes to the Company's IRP-based competitive solicitations; (vi) provided an overview of the Company's research on best practices for competitive procurement of renewable PPAs; and (vii) provided an overview of the Company's 2021 Natural Gas Plant RFP.

**Q. What approvals does the Company request from the Commission regarding your direct testimony?**

A. As explained in my direct testimony, the Company requests the following:

1. Approval to remove the cap on FCM and the applicability of FCM on all future PPAs and PPA amendments;

2. Clarification that the required review of the Company's PURPA avoided cost construct is adequately met through the IRP filings that the Company has agreed to file every three years;

3. Treatment of full avoided cost eligibility for QFs at or below 150 kW in size the same as QFs greater than 150 kW in size;

4. Removal of the requirement to offer to PURPA QFs any remaining capacity from each annual solicitation at full avoided cost rates;

5. Approval to reduce the PURPA Standard Offer Contract and Tariff from 2 MW to 100 kW and replace the current capacity compensation methodology;

6. Approval to offer QFs eligible for full avoided cost rates PPAs with a maximum term length of 20 years;

7. Approval to remove compensation for capacity from the reduced avoided cost rate;

8. Approval to the change the solicitation ownership structure from at least 50% from PPAs and 50% Company-ownership to a structure of at least 50% Company-ownership with the remaining 50% coming from either PPAs or Company-ownership, depending on economics. The proposed ownership structure will also be viewed over the longer term period, as opposed to annually;

9. Approval for additional flexibility in the competitive solicitations by being able to select more or less capacity than the solicited MW target in each annual solicitation and removing the requirement that remaining capacity from each solicitation be made available to PURPA QFs;

10. Confirmation that the Company's proposal to continue seeking approval of PPAs, Company-owned projects, and resets of PURPA full avoided cost rates stemming from competitive solicitations through *ex parte* approval is appropriate; and

11. Approval of the selection and proposed purchase of the DIG, Kalamazoo and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. In the alternative, while complying with all other provisions of the Code of Conduct, the Company requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Kalamazoo, and Livingston plants from CMS Enterprises.

12. Approval of any mechanisms necessary to implement these requests.

**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<br>**CONSUMERS ENERGY COMPANY**<br>for Approval of an Integrated Resource Plan<br>under MCL 460.6t, certain accounting<br>approvals, and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21090 |

**PROOF OF SERVICE**

STATE OF MICHIGAN )
) SS
COUNTY OF JACKSON )

Jennifer Joy Yocum, being first duly sworn, deposes and says that she is employed in the Legal Department of Consumers Energy Company; that on October 11, 2021, she served an electronic copy of the Revised Testimony of Company witness Norman J. Kapala and Exhibits A-50 (NJK-1), A-51 (NJK-2), A-55 (NJK-6), and A-57 (NJK-8), and the Revised Testimony of Company witness Keith G. Troyer upon the persons listed in Attachment 1 hereto, at the e-mail addresses listed therein.

Jennifer Joy Yocum

Subscribed and sworn to before me this 11th day of October, 2021.

Crystal L. Chacon, Notary Public
State of Michigan, County of Ingham
My Commission Expires: 05/25/24
Acting in the County of Jackson

**ATTACHMENT 1 TO CASE NO. U-21090**

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