November 11, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21870

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Official Exhibit List and Public Exhibits of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan; and
- Proof of Service.
- Please note that MEC-6C, MEC-11C, MEC-14C, MEC-29C, and MEC-35C are filed under seal and will only be served to those with an executed non-disclosure certificate pursuant to the Protective Order.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher M. Bzdok
Date: 2025.11.11 12:58:12 -05'00'

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21870

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	Case No. U-21870

OFFICIAL EXHIBIT LIST AND EXHIBITS OF MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND CITIZENS UTILITY BOARD OF MICHIGAN

MEC-1	Scott Reeves CV
MEC-2	U21870-MNSC-CE-0315
MEC-3	U21870-MNSC-CE-0313
MEC-4	Tyler Comings CV
MEC-5	U21870-MNSC-CE-0200(a) and Attachment 1.
MEC-6C	U21870-MNSC-CE-0070_ATT_0001_CONF
MEC-7	U21870-MNSC-CE-0072(c)
MEC-8	U21870-ST-CE-0004_ATT_0004
MEC-9	U21870-ST-CE-0004_ATT_0025
MEC-10	U21870-MNSC-CE-0071_ATT_0004
MEC-11C	U21870-MNSC-CE-0071_ATT_0003 CONF
MEC-12	U21870-MNSC-CE-0072_ATT_0004
MEC-13	U21870-MNSC-CE-0226(b).
MEC-14C	U21870-ST-CE-0007_ATT_0001_CONF
MEC-15	Resume of Caroline Palmer
MEC-16	U21870-MNSC-CE-221
MEC-17	U21870-MNSC-CE-0222
MEC-18	U21870-MNSC-CE-0214
MEC-19	U21870-MNSC-CE-0253 and Attachment 1
MEC-20	U21870-MNSC-CE-0255
MEC-21	U21870-MNSC-CE-0256
MEC-22	U21870-MNSC-CE-0257
MEC-23	U21870-MNSC-CE-0215
MEC-24	*Reserved*
MEC-25	*Reserved*
MEC-26	*Reserved*

MEC-27	U21870-MNSC-CE-0764
MEC-28	U21870-MNSC-CE-0765
MEC-29C	U21870-AG-CE-0478_Hayward_Attachment 3a Conf. and U21870-AG-CE-0478_Hayward_Attachment 5 Conf.
MEC-30	U21870-MNSC-CE-0766
MEC-31	U21870-MNSC-CE-0767
MEC-32	*Reserved*
MEC-33	*Reserved*
MEC-34	U21870-MNSC-CE-0938
MEC-35C	U21870-MNSC-CE-0209 Attachment Conf.
MEC-36	U21870-MNSC-CE-0939
MEC-37	*Reserved*
MEC-38	U21870-MNSC-CE-0768
MEC-39	U21870-MNSC-CE-0769
MEC-40	U21870-MNSC-CE-0803
MEC-41	*Reserved*
MEC-42	U21870-MNSC-CE-865
MEC-43	U21870-MNSC-CE-866
MEC-44	U21870-MNSC-CE-867 + Attachment
MEC-45	U21870-MNSC-CE-868
MEC-46	U21870-MNSC-CE-0801
MEC-47	U21870-MNSC-CE-0802
MEC-48	U21870-MNSC-SLT-1, 2, & 3
MEC-49	MPSC Staff's Answer to MNSC 1st DRs 1-2
MEC-50	CECo Part III Filing Requirements Attachment 133
CUB-1	Matt Bandyk Resume
CUB-2	Overall Rate of Return
CUB-3	Equity Risk Premium
CUB-4	Beta
CUB-5	CAPM Analysis
CUB-6	Long-Term Growth Rate
CUB-7	DCF (with Earnings Growth Rates)
CUB-8	DCF (with Dividend Growth Rates)
CUB-9	Interest Coverage Ratio
CUB-10	ROE for U.S. Stock Market
CUB-11	Resume of Douglas Jester
CUB-12	TEP-Managed vs Overall EV Growth
CUB-13	U21870- MNSC-CE 0569
CUB-14	U21870-MNSC-CE-0576
CUB-15	U21870-MNSC-CE-0578
CUB-16	U21870-MNSC-CE-0583

CUB-17	U21870-MNSC-CE-0570
CUB-18	U21870-MNSC-CE-0582
CUB-19	U21870-MNSC-CE-0577
CUB-20	U21870-MNSC-CE-0579
CUB-21	Resume of Richard Bunch
CUB-22	U21870-MNSC-CE-0560 and 0561
CUB-23	Change in CXCO Historical O&M
CUB-24	U21870-SA-CE-113 and 114
CUB-25	Labor Costs Adjustments
CUB-26	Proposed LVD Pole Replacement Surge
CUB-27	SAIDI Benefits Modified U21870-AG-CE-0424_Kelly_ATT_1
CUB-28	2025-2030 Line Clearing O&M
CUB-29	Present Value of Each Undergrounding Project
CUB-30	Sorted Benefits

Date: November 11, 2025

By:

Troposphere Legal, PLC
Counsel for MNSC

Digitally signed by Christopher M. Bzdok
Date: 2025.11.11 12:59:23 -05'00'

Christopher M. Bzdok (P53094)
Tracy Jane Andrews (P67467)
Holly L. Hillyer (P85318)
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4000

Scott Reeves
Managing Consultant

ENERGY FUTURES GROUP

Professional Summary

Scott brings over 18 years of experience leading research aimed at improving strategy and performance of energy programs. His expertise includes quantitative and qualitative evaluation research, income-qualified programs, non-energy benefits, and locational analysis. He is also experienced with demand response, having led numerous evaluations and consulting on research and program design, impact methods, customer energy journey, and market savings potential. Scott holds a Masters of Public Affairs from Indiana University and a B.A. in Anthropology from the University of Puget Sound. He is currently on the Northwest Power and Conservation Council's Demand Response Advisory Committee.

Experience

2025-present: Managing Consultant, Energy Futures Group, Hinesburg, VT

2021-2024: Director, Cadeo Group, Portland, OR

2006-2021: Senior Associate, Cadmus Group (formerly Quantec), Portland, OR

2006-2007: Analyst, Indiana Department of Housing and Community Development, Indianapolis, IN

Education

B.A., Comparative Sociology, University of Puget Sound, 2003

M.P.A., Public Affairs, Indiana University, 2007

Select Projects

- Citizens Action Coalition (Indiana). Provides technical review and recommendations for utility program design and planning studies of demand response and dynamic pricing resources. Develops expert testimony assessing utility DR portfolio and planning forecasts, identifying additional opportunities to develop DR resources to reduce peak loads, decreasing costs to ratepayers, and providing equitable pathways for participation. Assesses utility economic parameters, methods, and modeling of DSM programs. (2023-present)
- Portland General Electric (PGE). *Residential Demand Response Pilot Evaluations.* Led Cadmus' evaluation and planning support of PGE's residential demand response pilot programs, including peak time rebates, behavioral demand response, time varying pricing, and smart thermostat direct load control. Conducted seasonal evaluations providing insight on customer experience, load impacts, scalability, and use case parameters. (2016-2021)
- Portland General Electric (PGE). *Time-of-Day Rate Design Support.* Conducted research and analytics informing new TOU rate schedules, including development of rate impact calculator providing sensitivity testing for load shifting scenarios to assess bill impacts of three rate options. (2020-2021)
- National Resources Defense Council (NRDC). *New Jersey Electrification Analysis Modeling*. Developed a model to assess customer economics of electrifying single-family homes, estimating net

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present values between gas baseline and electric alternatives. Analysis focused on full home electrification and modeled capital equipment and operating costs at an end-use level across several scenarios, including by utility territory and considering the impact of weatherization. (2025)

- Black Hills Energy (BHE). Developed research design and sampling plans for a time-varying pricing pilot design and evaluation. Provided expert testimony supporting the utility filing, including response to discovery and rebuttal. (2018-2019)
- Environmental Defense Fund (EDF). *Illinois Performance Metric and Multiyear Grid Plan Proceedings*. On behalf of EDF, participated in Illinois Commerce Commission-led Performance Metric and Grid Plan workshops; developed testimony focused on affordability and peak load reduction topics within both ComEd and Ameren performance metric and grid plan proceedings. (2025-2026)
- Connecticut Public Utilities Regulatory Authority (PURA). Supports the CT Innovative Energy Solutions (IES) pilot administration (as a subcontractor to Current Energy Group), including development of evaluation criteria, scoring rubric, and cost effectiveness methodology. Developed model for assessing cost effectiveness and valuation of energy/non-energy impacts for a wide range of innovative energy pilots supporting grid modernization, resource flexibility, decarbonization, and equity. (2022-present)
- Northwest Energy Coalition (NWEC) / EarthJustice. Provided technical review and developed testimony on Puget Sound Energy's general rate case and clean energy implementation plan (CEIP) filings, focusing on clean energy goals and equity associated with DR/DER program planning and design proposals. (2022-2023)
- Sierra Club / NRDC. *Xcel Colorado DSM Strategic Issues Proceeding*. Provided technical review, analysis, and developed testimony aimed at setting goals for demand response and beneficial electrification programs. (2022-2023)
- Portland General Electric (PGE*). Smart Grid Test Bed (SGTB) Project Evaluations.* Led the Cadmus evaluation of phase 1 of its SGTB project focused on the acceleration of flexible load resources and strategies for engaging customers in demand response. Assessed messaging campaigns testing different value propositions and factors that resonate with different customer segments. Developed experimental design to test various research questions, including messaging influence on behavioral demand response, encouragement to co-enroll or migrate existing participants to additional DR programs, and testing effectives of pre-notification on event participation. Provided insights no barriers to participation and strategies to maximize engagement, retention, and satisfaction for customers participating in demand response. Beginning in 2022, led several Cadeo research studies of stakeholders and implementation contractors as part of SGTB phase 2. (2019-2021, 2022-2024)
- Portland General Electric. *Locational Assessment for Community Benefit Targeting*. Led analysis to develop composite indices for improved locational targeting of equity, environmental, and resiliency benefits in distribution system planning. (2021-2022)
- Portland General Electric (PGE). *DER Non-Energy Impact Valuation Study*. Led Cadmus' assessment of non-energy impacts associated with a suite of DERs, overviewing benefits by cost test perspective and product type, and highlighting those with greatest potential benefit. Identified

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studies to leverage for near-term cost effectiveness modeling, and benefits most impact to underserved communities. (2021)

- Portland General Electric (PGE). *Community Benefit Indicator (CBI) Assessment*. Conducted study developing suite of CBIs, composed of monetizable benefits and trackable metrics, and methods for application that PGE will use to reflect community values in integrated resource planning, distribution system planning, and program delivery. (2024-present)
- Seattle City Light (City Light). Led evaluations of two City light pilot programs, Smart Thermostat Direct Load Control and Commercial Fleet Charging pilots. Developed evaluation research designs, logic models and evaluability assessments, and key performance indicators. Led in-depth interviews with a range of internal stakeholders to assess current understanding, value, and use cases for demand response. Conducted a range of other process and evaluation activates, including participant surveys to assess customer experience and load impact analysis. (2022-2024)
- Northwest Power and Conservation Council's Regional Technical Forum (RTF). *Flexibility Benefit Valuation Study*. Led study exploring benefits of demand flexibility unlocked through interactions of energy resources, and how these are being captured in current power system planning methods. Developed framework for considering different types of flexibility benefits, highlighting examples of multidirectional interactions, and valuation methods for future application. (2022-2023)
- Washington State Department of Commerce. *WA Energy Navigator Study.* Led research, stakeholder facilitation, and provided recommendations for proposed statewide energy navigator entity, aimed at increasing access of efficiency and electrification programs with an emphasis on reaching underserved communities. Conducted expert interviews, web surveys, 170 participant virtual workshop to refine navigator roles/responsibilities, how it interacts with existing programs, and how it can achieve goals of scaling participation and access of energy offerings to residents. Provided legislative memo reflecting research findings, informing strategic vision and tactical recommendations. (2023-2024)
- Maryland Department of Housing and Community Development (DHCD). Led Cadmus' statewide evaluation of EmPOWER Maryland's low-income efficiency programs for single family and multifamily buildings. Provides technical oversight and conducts annual evaluation research across a suite of income-qualified programs and customer segments, including consumption analysis, calibrated simulation modeling, engineering analysis, TRM measure development, cost effectiveness, on-site M&V, participant surveys, net-to-groups, and non-energy benefits. Recently developed a cost-effectiveness model to evaluate the societal cost test, including valuation of energy and non-energy benefits. (2016-present)

Select Publications and Presentations

- Reeves, Scott. *Transforming Income-Qualified Programs: Washington State Energy Navigator Study*. Efficiency Exchange Conference. May 2025.
- Reeves, Scott. *Unlocking Demand Flexibility – Accounting for EE/DR Interactivity In Resource Planning*. Efficiency Exchange Conference. March 2023

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- Reeves, Scott and Emma Johnson. *Overcoming Winter DR Challenges – Results from Seattle's BYOT Pilot.* Peak Load Management Alliance Spring Conference. May 2024.
- Widder, Sarah, Scott Reeves, Emma Johnson, and Lucas Judson. *Demand Flexible Line Voltage and Zonal Thermostat Market Scan; Winter DR Results from SCL BYOT Pilot.* NEEA Product Council Series, Emerging Technology and Product Management. Webinar. August 2024.
- Reeves, Scott, Jess Siegel, Josh Keeling, and Sarah Widder. 2023. *Accounting for interactivity In Resource Planning and Impacts of Demand Flexibility***.** Regional Technical Forum and Northwest Power and Conservation Council. https://nwcouncil.app.box.com/v/2023FebCadeoInteract

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Question:

6. Has Consumers ever had separate rates for customers with electric heating? If so, please provide the following information:

a. Rate name and customer class for each.
b. Periods in which each rate was active (including start and end dates).
c. Information on rate structure and eligibility.
d. If and how each rate differed from then-current rates.
e. When each rate was discontinued and why.

Response:

Yes

a. Originally, in 1963, residential space heating was offered on a stand-alone rate, Residential Electric Heating Rate A-1. At the time of termination for residential space heating in 2008, it was offered as a provision that was added on to eligible residential rate options. Commercial and Industrial Electric Heating Service was offered as a stand-alone, separately metered rate.

b. Residential space heating was offered from 1963 through 2008. The first rate for residential space heating effective for service rendered on and after March 1, 1963 and was authorized in the order dated February 7, 1963 in Case No. U-1201. After many iterations and minor pricing modifications, residential space heating was ultimately terminated in the order issued on June 19, 2008 in Case No. U-15245, effective for service rendered on and after June 20, 2008.

c. In 1963, Residential Electric Heating Service Rate "A-1" was available to residential customers provided the customer had permanently installed and uses electric heating equipment as the primary source of space heating in the residential dwelling. At the time of termination, the eligibility requirement was similar "When service is supplied to a residence which has permanently installed electric heating equipment, either total electric or an electric heat pump supplemented by a fossil fuel furnace." Price per kWh was determined by the tier of consumption – prices were the same year-round (no seasonal component).

   Over the years, the pricing structure became a tiered over/under 500 kWh or 600 kWh and a seasonal component was added. At the time of termination, the residential space heating provision had a seasonal tiered pricing structure in which the first 20 kWh were billed at one price per kWh and all kWh over 20 kWh daily were billed at a lower rate during the billing months of October through May.

The original eligibility of Commercial and Industrial Rate GH required separate metering for electric space heating. No other device, with the exception of electric air conditioning equipment, could be connected. The electric space heating equipment must be used as the primary source of space heating. At the time of termination, electric water heaters meeting the Company's standards were allowed.

When first introduced in 1965, customers paid a flat rate per kWh of 1.5 cents with a minimum charge of $1.40. In July 1965, the minimum charge was revised to $18.00 for seasonal customers. In 1967, heating by light systems when the lighting provides a major portion of the heating requirements. At the time of termination, customers on General Service Electric Heating Secondary Rate GH paid a season flat rate per kWh with the price per kWh being higher during the summer months of June through September and a lower price per kWh for the billing months of October through May.

In addition, "Insulation Requirements for Electric Heat Customers" were located on Tariff Sheet No. C-5.00 applicable for customers taking service on the residential space heating provision and General Service Space Heating Rate GH at the time of termination. These requirements were also eliminated from the rate book effective for service rendered on and after June 20, 2008 in compliance with the order in U-15245.

A copy of some of the previous tariffs are attached.

d. Both the Residential Electric Heating Service Rate and the provision charged a declining block rate for usage during a defined winter period. This contrasted with the standard residential rate which charged a single energy charge for all usage during the winter.

e. Residential space heating was terminated in Case No. U-15245, with the following support in witness Miller's direct testimony: "Is Consumers Energy proposing to discontinue the space-heating provision? *Yes. Like water-heating, this provision was historically used as a means to compete for additional residential electric load. Customers currently taking this provision are charged under a two-tiered rate structure during the winter months (October – May). The first tier (first 20kWh/day) of the space-heating provision is priced at the same rate level as the standard residential rate schedule. Customers are provided a discount for consumption in excess of the first tier. A rate design that better reflects temporal cost spreads (seasonality) would be far simpler and more equitable.*" The residential space heating provisions were terminated effective with service rendered on and after June 20, 2008. General Service Space Heating Rate GH was terminated with service rendered on and after December 1, 2008 in the order issued on June 19, 2008 in Case No. U-15245 when the rate was rolled into General Service Secondary Rate GS as a part of the Company's new rate structure as supported by Exhibit A-35 (HWM-3R) dated July 2007 on page 6 of 6, as discussed above in part b.

Witness: Laura M. Connolly
Date: September 3, 2025

Question:

4. What, if any, existing pilots or programs (e.g., efficiency, decarbonization) does Consumers have to encourage the installation of heat pumps and heat pump water heating equipment?

Please list each program and specific intervention (e.g., incentive/rebate, customer or contractor education)?

Response:

Pilot Programs (2025 program year):

- All-Electric New Home Construction – the pilot provides incentives for completed homes that meet ENERGY STAR NextGen, US DOE Zero Energy Ready Home, or Passive House Institute/Phius certification standards. Provides up to $20,000 in incentives to home builders if their completed home meets any of the above criteria.
- New Manufactured Homes – the pilot provides incentives for companies building manufactured homes to an ENERGY STAR or US DOE Zero Energy Ready standard. Provides between $50 and $3,000, depending on equipment installed and number of sections in the housing unit, to companies producing manufactured homes that meet

Contractor Rebates:

Consumers Energy actively encourages the installation of heat pump technology in program eligible instances by:

- Training contractors to understand which customers are eligible for incentive related to heat pump technology. This begins with the contractor onboarding and ongoing training and support provided by the account management team.
- Various items have been developed to support the trade ally network's understanding of the benefits of heat pump technology. This includes a one-page contractor engagement piece and customer leave behinds.
- The Consumers Energy team also engages in the MI Heat Pump Collaborative. This collaborative provides opportunities to gain and share information and resources related to heat pump technology with a wide group of industry professionals focusing on the advancement and adoption of heat pump technology.
- Specific interventions include:
    - Contractor Education - One Page Awareness Piece, General Heat Pump Awareness during contractor onboarding training, Education relative to incentives offered for qualifying heat pump technology installations
    - Customer Awareness - Creation and distribution of customer leave behind
    - Collaboration - Member of Mi Heat Pump Collaborative

Heat pump rebates include:

Heat Pump Rebates	Rebate Amount
Air-Source Heat Pump - SEER2 15.2 to 15.99 or Higher	$300
Ground-Source Heat Pump - EER 17 to 18.99 EER	$200
Ground-Source Heat Pump - EER 19 or Higher	$300
Ductless Mini-Split Heat Pump - Must be minimum SEER2 17 to 25 or greater and minimum HSPF2 8 to 12.5 or greater	$350

Heat Pump Water Heater - up to $750 incentive and $500 for self-submit.

Midwest 120-Volt Heat Pump Water Heater Study:

Consumers Energy took part in a 120V Heat Pump Water Heater study with 2 other Midwest Utilities. The goal of the field study was to independently field-verify the 120-volt heat pump water heaters for energy performance, installer acceptance, and user satisfaction to advance market adoption and inform energy efficiency program designs in the Midwest.

Multifamily Programs Response:

The Multifamily program is part of the Michigan Heat Pump Collaborative (MIHPC). Through targeted outreach, the program promotes MIHPC resources—including trainings, resource guides, and annual summits—to contractors and trade allies. *Please see Section 2.5.2 in the Consumers Energy Filing U-21680 (page 85) where it talks about our continued collaboration in the Michigan Heat Pump Collaborative as well as the Michigan Heat Pump Collaborative website. (*https://www.miheatpumps.com/)

As part of its prescriptive approach, the Multifamily program offers tiered incentive levels to support the installation of heat pump systems in multifamily buildings. These incentives are structured to encourage participation and maximize energy savings. Notably, the Multifamily program provides elevated incentives for Income Qualified customers, exceeding those listed in the standard Market Rate Catalog, to ensure equitable access to high-efficiency solutions. *Please reference the applicable measures in the Program Catalog*

*(*https://save.consumersmultifamilysavings.com/2025catalog) *for further details.*

Education includes participation in MIHPC, contractor and customer education.

The Multifamily programs provide tiered incentives/ rebates for installation of heat pumps. Please reference the applicable measures in the Program Catalog

(https://save.consumersmultifamilysavings.com/2025catalog) for further details (ex: rebate level, specifications, tiers, etc.)

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Page **3** of **3**

Single Family Income Qualified*:*

The IQ Single Family Program is not currently running any pilot programs. Contractors are trained and instructed to install heat pump water heaters when electric resistance water heaters are present.

Witness: Alex M. Gast
Date: September 4, 2025

Tyler Comings, Principal Economist

6 Liberty Sq., PMB 98162, Boston, MA, 02109 ⌘ tyler.comings@aeclinic.org ⌘ 617-863-0139

PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Principal Economist, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA

Master of Arts in Economics, 2007

Boston University, Boston, MA

Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

AFFILIATIONS

Society of Utility and Regulatory Financial Analysts (SURFA)

Member

Global Development and Environment Institute, Tufts University, Medford, MA.

Visiting Scholar, 2017 – 2020

CERTIFICATIONS

Certified Rate of Return Analyst (CRRA), professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

PAPERS AND REPORTS

Lala, C.T., J.R. Castigliego, T. Comings, and E. Seliga. 2024. *TVA's Kingston Fossil Plant: An Economic Assessment of Replacement Alternatives*. Applied Economics Clinic. Prepared for the Southern Environmental Law Center (SELC). [Online]

Castigliego, J.R., T. Comings, S. Alisalad, and E.A. Stanton. 2021. *Background Report: Benefits of Coal Ash Cleanup and Remediation*. Applied Economics Clinic. Prepared for Earthjustice. [Online]

Woods, B., E. A. Stanton, T. Comings, and E. Tavares. 2019. *Emission Reduction Synergies for Massachusetts Community Choice Energy Programs, Heat Pumps and Electric Vehicles*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Lopez, R., T. Comings, E.A. Stanton, and E. Tavares. 2019. *Home Heat Pumps in Massachusetts*. Applied Economics Clinic. Prepared for Green Energy Consumers Alliance. [Online]

Comings, T., B. Woods, and M. Majumder. 2019. *Updated Costs of Community Choice Energy Aggregation in Boston*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., R. Lopez, and B. Woods. 2018. *A Critique of an Industry Analysis on Claimed Economic Benefits of Offshore Drilling in the Atlantic*. Applied Economics Clinic. Prepared for the Southern Environmental Law Center. [Online]

Stanton, E.A., and T. Comings. 2018. *Massachusetts Clean Energy Bill Provisions Boost Jobs and Strengthen the State's Economy.* Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, R. Wilson, S. Alisalad, E.N Marzan, C. Schlegel, B. Woods, J. Gifford, E. Snook, and P. Yuen. 2018. *An Analysis of the Massachusetts 2018 'Act to Promote a Clean Energy Future' Report*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Comings, T., E.A. Stanton, and B. Woods. 2018. *The ABCs of Boston CCE*. Applied Economics Clinic. Prepared for Barr Foundation. [Online]

Stanton, E.A., T. Comings, and A. Sommer. 2018.*The Husker Energy Plan: A New Energy Plan for Nebraska*. Applied Economics Clinic. Prepared for the Nebraska Wildlife Foundation. [Online]

Comings, T. and B. Woods. 2017. *The Future of the Martin Drake Power Plant*. Applied Economics Clinic. Prepared for Green Cities Coalition and Southeastern Colorado Renewable Energy Society. [Online]

Wilson, R., T. Comings, and E.A. Stanton. 2017. *Ratepayer Impacts of ConEd's 20-Year Shipping Agreement on the Mountain Valley Pipeline.* Applied Economics Clinic. Prepared for the Environmental Defense Fund. [Online]

Knight, P., A. Horowitz, P. Luckow, T. Comings, J. Gifford, P. Yuen, E. Snook, and J. Shoesmith. 2017. *An Analysis of the Massachusetts Renewable Portfolio Standard*. Synapse Energy Economics and Sustainable Energy Advantage. Prepared for NECEC in Partnership with Mass Energy. [Online]

Knight, P., S. Fields, F. Ackerman, T. Comings, and A. Allison. 2017. *Empowering Kentucky*. Synapse Energy Economics. Prepared for Kentuckians for the Commonwealth. [Online]

Comings, T. and A. Allison. 2017. *More Mileage for Your Money: Fuel Economy Increases While Vehicle Prices Remain Stable*. Synapse Energy Economics. Prepared for Consumers Union. [Online]

Cook, R., J. Koo, N. Veilleux, K. Takahashi, E. Malone, T. Comings, A. Allison, F. Barclay, and L. Beer. 2017. *Rhode Island Renewable Thermal Market Development Strategy*. Meister Consultants Group and Synapse Energy Economics. Prepared for Rhode Island Office of Energy Resources. [Online]

Fisher, J., P. Luckow, A. Horowitz, T. Comings, A. Allison, E.A. Stanton, S. Jackson, and K. Takahashi. 2016. *Michigan Compliance Assessment for the Clean Power Plan: MPSC/MDEQ EPA 111(d) Impact Analysis*. Prepared for Michigan Public Service Commission, Michigan Department of Environmental Quality, and Michigan Agency for Energy. [Online]

White, D., P. Peterson, T. Comings, and S. Jackson. 2016. *Preliminary Valuation of TransCanada's Hydroelectric Assets*. Prepared for the State of Vermont. [Online]

Comings, T., S. Jackson, and J. Fisher. 2016. *The Economic Case for Retiring North Valmy Generating Station*. Synapse Energy Economics. Prepared for Sierra Club. [Online]

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Resume dated April 2025

Question:

2. Refer to Company attachments 126B, 126D, 126F, 126H and 126J.

a. Apart from fuel costs, do the costs in "Total Production Expenses" for the Covert, Jackson, and Zeeland gas plants shown in each attachment only include variable O&M costs?

   i. If not, please provide a breakdown of fixed and variable O&M costs included in "Total Production Expenses" at each of the three plants from 2020 through 2024 (inclusive).

b. Are all variable O&M costs for the Covert, Jackson, and Zeeland gas plants accounted for in "Total Production Expenses"?

   i. If not, please provide the remaining variable O&M costs at each of the three plants from 2020 through 2024 (inclusive).

Response:

a. No. The Total Production Expenses include both fixed and variable O&M expenses other than fuel & chemical reagent expenses as well as a corporate allocation of support costs. See also the response to U21870-MNSC-CE-0199.

   i. See attachment U21870-MNSC-CE-0200_ATT_0001 for a reconciliation of attachments 126B, 126D, 126F, 126H and 126J to workpaper WP-24. Variable O&M expense on workpaper WP-24 is reflected in major maintenance expense.

b. Yes.

   i. N/A.

Witness: RICHARD T. BLUMENSTOCK
Date: August 13, 2025

Reconciliation O&M	2024 Zeeland	2024 Jackson	2024 Covert	2023 Zeeland	2023 Jackson	2023 Covert	2022 Zeeland	2022 Jackson	2022 Covert	2021 Zeeland	2021 Jackson	2021 Covert	2020 Zeeland	2020 Jackson	2020 Covert
O&M (Workpaper WP -24)	11,199,374	11,615,811	13,507,741	9,618,496	8,817,175	7,412,668	11,029,441	10,543,550	3,924	10,893,156	10,338,207	-	8,944,620	9,853,124	-
Fuel on FERC page	97,841,872	42,805,781	115,587,910	92,883,789	46,050,479	82,623,802	215,225,449	125,247,561		102,398,414	75,858,928	-	61,784,213	35,194,400	-
allocations from Engineering and Corporate dept.:															
Energy Supply/EPMES	382,547	315,386	284,874	330,446	269,922	184,041	304,510	212,923		280,285	180,154		457,260	282,717	
IT Cost	314,473	266,233	1,142,831	508,662	429,379	-	517,200	422,056		624,111	529,702		45,642	414,299	
Security Cost	54,692	47,096	204,506	42,996	36,268	-	44,619	36,611		61,161	52,361		616,054	39,581	
Gen Ops/ERBS	246,929	225,079	661,931	144,949	134,955	42,501	258,286	198,084		103,404	136,433		159,714	483,652	
MDNR Fees	35,307	48,981	-	30,590	48,398	-	33,187	42,151		30,643	49,405		28,841	47,550	
Total	110,075,193	55,324,367	131,389,792	103,559,928	55,786,576	90,263,012	227,412,692	136,702,936	3,924	114,391,174	87,145,190	-	72,036,345	46,315,323	-
FERC Form 1/MPSC - Total Production Expenses	110,075,193	55,324,367	131,389,792	103,559,929	55,786,576	90,263,013	227,412,692	136,702,935	NA	114,391,175	87,145,186	NA	72,036,345	46,315,322	NA
Variance	(0)	0	(0)	1	(0)	1	0	(1)		1	(4)		(0)	(1)	
	126J			**126H**			**126F**			**126D**			**126B**		

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-6C

Question:

3. Refer to Company's filing Part III, Attachment 131, for all projects at the Covert, Jackson and Zeeland plants, please provide (where applicable):

a. The earliest and latest project charter.

b. Any economic analysis performed, including present value ratio (PVR) or internal rate of return (IRR) calculations, including all supporting analyses and documentation used in such calculations (preferably in Excel format).

c. Please identify those projects which the Company deems required for safety purposes, including an explanation for why that is the case.

d. Please identify those projects which the Company believes that, if not performed, the unit would not operate, including an explanation for why that is the case.

Response:

a. Per discussion with MNSC council, the Company has provided concept approvals which provide an analysis of the work to be performed, a discussion of alternatives, including doing nothing, and a selected alternative. Attachment U21870-MNSC-CE-0072_ATT_0001 reproduces select fields from Part III Attachment 131 for all projects at the Covert, Jackson, and Zeeland generating stations. This attachment identifies the work type and category, job description, reason for the work to be performed, and the applicable attachment representing the concept approval for the project. 8 other attachments are attached to this response which reflect concept approvals not previously provided in discovery in this proceeding.

   The projected capital investment for certain routine capital projects such as small capital and base outage for each generating station are primarily based upon historical spend. Sheet 2 of this attachment provides 5 years of history of investment for each of these work categories for both the Jackson and Zeeland generating stations and all available investment history for Covert generating station since its acquisition on June 1, 2023.

b. The only projects identified as economic in nature are the Zeeland Phase I and II turbine projects. Please refer to confidential Attachments U21870-ST-CE-0007_ATT_0001_CONF and U21870-ST-CE-0007_ATT_0002_CONF for the economic analysis. Also refer to the Company's response to discovery question U21870-MNSC-CE-0071.

c. None of the projects for the Covert, Jackson, and Zeeland generating stations are being performed based upon safety.

d. Please see concept approval documents identified in Attachment U21870-MNSC-CE-0072_ATT_0001 for the basis for the specific work. Some work is required for warranty such as the LTSAs, some of it is based upon economics (Zeeland Phase I and II), some is performed based on failed equipment, some

of it is performed based upon required computer-related equipment upgrades in order to continue to operate the generating units.

Witness: RICHARD T. BLUMENSTOCK
Date: July 24, 2025

Consumers Energy Count on Us®

Concept Approval

Covert Generating Station Generator Step-Up transformer replacement.

Date: 12/1/2023

Prepared by: John Slinkard and Paul Ohep

Figure 1. Covert Generating Station aerial view.

Executive Summary

Addressing the critical need for operational reliability at Consumers Energy's power generation facilities, this proposal explores the optimal strategy for ensuring a backup Generator Step-Up (GSU) transformer is readily available at Covert Generating Station. The urgency of this project stems from the increased risk of transformer failure due to the presence of corrosive sulfur, coupled with long procurement lead times of 2 to 4 years for GSU transformers.

Four options were meticulously evaluated: overhauling the existing GSU, procuring a new site-specific spare GSU, exploring leasing alternatives, and purchasing a single larger spare GSU that could serve both Covert Generating Station and Zeeland Generating Station.

Option 2, which proposes the procurement of a site-specific spare GSU, has emerged as the most viable solution. It ensures immediate availability of a replacement transformer, minimizing downtime and associated financial losses. This option mitigates potential complications arising from multiple installations associated with utilizing a leased GSU or usage of multi-site transformer. Moreover, it also offers the opportunity for CE to recover some costs through leasing agreements with other utilities.

This initiative, backed by the Asset Strategy Group, ensures that Covert Generating Station is equipped to address transformer failures swiftly and efficiently. Implementing this solution safeguards our ability to deliver reliable power to our consumers and demonstrates a strategic foresight in asset management.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$16,355,000

Proposed Start Implementation Year

2024

Project Span Whole Years

4 Years

Problem Description

The Covert Generating Station features a combination of three gas turbine-powered plants and three steam turbine-powered plants, arranged in a one-on-one combined cycle configuration. This setup entails that each gas turbine unit powers the secondary winding of a three-winding transformer (GSU), while the corresponding steam-powered unit powers the tertiary winding.

GSU Explained: A Generator Step-Up (GSU) transformer is a critical component that steps up the voltage generated by a turbine before it is transmitted to the grid, ensuring efficient power transfer.

A GSU's failure can lead to significant power generation issues. Specifically, the GSUs at Covert are rated for 500 MVA and are equipped with forced oil and forced air cooling mechanisms. If a GSU were to fail, both the gas and steam turbine units connected to it would be unable to transmit power, leading to a potential loss of up to 400 MVA of generation capacity. This would prevent the generation of market value for Consumers Energy and its customers.

Further complicating the situation is the long lead time of 2 to 4 years for procuring a replacement GSU, and the lack of spare units at other facilities. The plant is projected to operating until at least 2040, thus making it crucial to have a reliable GSU ready for replacement.

Figure 2. Typical Step-Up transformer

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $130.9 million ($16.4M for new GSU plus $114M in energy value and potential capacity lost)

This approach involves continuing the operation without procuring a spare GSU, essentially accepting the risks associated with a potential GSU failure. When under load, a failure of the GSU transformer is a serious concern, not only because of the high financial costs but also due to safety implications. Such a failure could lead to cascading consequences where other critical equipment, such as the generator or the 345kV breaker, could be damaged or fail.

The GSU transformer is a critical component, and its failure would render the combined plant, consisting of one steam turbine and one gas turbine, inoperative. An overhaul or replacement of a GSU transformer, in the event of a failure, is expected to take a minimum of 12 months.

There is an estimated 20% risk that the generator or the 345kV breaker might be damaged during an in-service failure of a GSU. The replacement cost for the generator is estimated at $20M and for a 345kV breaker, it is around $1M. These costs are not included in the alternative cost.

The economic considerations for not having a spare GSU transformer on site, with an anticipated downtime of a full year, are significant. The breakdown for both potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $66.6M:

For this option, where the procurement and installation of the new GSU transformer are involved, a critical consideration is the multi-year financial impact, as determined by the Midcontinent Independent System Operator (MISO). MISO calculates and accredits capacity based on a rolling three-year average of historical capacity credits. Therefore, any outage that exceeds the 30-day threshold can significantly affect these calculations.

Given the expected duration of the entire process is about one full year, this threshold will be exceeded. This prolonged downtime will, therefore, trigger the multi-year financial impact, altering the capacity accreditation and potentially affecting financial projections for several years.

Average ZRC Reduction Post-Outage:

- In the event of a 365-day outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for each season (based on 354 ZRCs per season).
- This scenario leads to a potential annual daily loss of 118 ZRCs per season for each of these three years (354 ZRCs-236 ZRCs).

2. **Cumulative Potential Loss of Capacity Value Over Three Years:**
    - The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 365-day outage and the additional 118 ZRCs/day applied over 90 days times four seasons over the subsequent three years.
3. **Calculation of Total Potential Loss:**
    - To estimate the potential capacity loss for this option:
        1. Calculate the Reduced Capacity Credits:
            - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
            - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        2. Add the Immediate Loss:
            - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (354 in this case). This gives us the immediate loss in capacity credits for that outage (31,860).
        3. Calculate the Total Revenue Loss:
            - Add the results from steps 1 and 2 to get a combined figure (63,720).
        4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
    - This leads to a total estimated potential loss of capacity value of an estimated $16.6 million per season over the three-year period following the outage.
    - The total potential capacity value impact for a one-year outage, accounting for all four seasons, and including the impact on the subsequent three years is given by multiplying $16.6 million times four, resulting in an estimated $66.6 million potential impact.

<u>Average energy value estimated loss - $47.9M:</u>

For the scenario of a transformer failure with no spare on-site, there is a substantial potential loss in energy production due to an assumed 365-day outage. This loss can be quantified by considering the Net Energy Value (NEV) for that station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

This analysis emphasizes the potential financial impact of not having a spare GSU on-site. Considering both the immediate potential loss of capacity value due to the outage, the reduced capacity credits in the subsequent three years as well as the energy value lost.

Overall advantages and disadvantages:

- **Advantages:** There is no immediate expenditure or need for storage.

- **Disadvantages:** This approach carries the highest long-term cost and risk, including the potential loss in revenue, safety hazards, and extended downtime for repairs or replacements.

2. Procure and Store a Spare GSU on-site Cost: $31.7M (including $15.3M in potential capacity value and energy value losses)

This alternative solution involves the strategic decision of procuring and maintaining a spare GSU transformer at the plant site.

- The procurement cost of the spare GSU is quoted at $12.5 million, based on an estimate from a well-known manufacturer of power transformers.

- The cost of constructing an appropriate foundation at the Covert site for the spare GSU is projected to be $200,000, as estimated by a specialized civil engineering company.

- Additional expenses related to engineering, Stand Up Transformer (SUT), and other logistical aspects are anticipated to be around $280,000.

- In the cost estimation process for large capital projects, it is a common industry practice to incorporate budget to account for unforeseen expenses that might occur during the project. The typical industry standard for such budgets can vary from 5% to 10% of the total project cost, depending on the project's complexity and risk level. For this specific project, we have included a conservative budget of 5% to the total estimated cost, considering our high predictability and control over project variables. Additionally, to cover regular operational and administrative expenses related to the project, a 20% overhead has been factored in. Consequently, the comprehensive cost estimate for this option now stands at $16.355 million (internal estimate).

- The economic considerations for procuring a spare GSU for the Covert Generating Station, with an assumed downtime of 31 days, are significant but more manageable when compared to leasing.

The breakdown for potential capacity lost, and average energy value lost are as follows:

Capacity value potential loss impacts - $11.2M:

For this option, the installation of the new GSU transformer stored on-site is anticipated to take approximately 30 days or slightly more. Specifically, if an outage exceeds 30 days, it triggers a potential multi-year financial impact due to the way MISO calculates and accredits capacity over time.

In this scenario, we will assume a worst-case scenario outage duration of 31 days within a single season. This results in the Station losing all 354 ZRCs (Zonal Resource Credits) for the season. This loss of ZRCs would result in a multiyear capacity impact, as capacity accreditation by MISO is based on a three-year average of historical capacity credits. It is important to note that if the outage had been limited to 30 days or less, or if the outage spans across parts of two separate seasons there would be no loss of ZRCs for either season, and consequently, no capacity impact.

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage during a single season, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the 31-day outage and the additional 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).

2. Add the Immediate Loss:
    - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (31 x 354 in this case). This gives us the immediate loss in capacity credits for that outage (10,974).
3. Calculate the Total Revenue Loss:
    - Add the results from steps 1 and 2 to get a combined figure (42,834).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

- This leads to a total estimated potential loss of capacity value of an estimated $11.2 million over the three-year period following the outage.

Average energy value estimated loss – $4.1M:

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 31-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 31-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 31 days = $4.1M

This figure represents the potential average revenue loss for the Covert Generating Station during the outage period.

On-site spare overall advantages and disadvantages:

Advantages:

- Having a spare GSU on-site ensures rapid restoration of operations in case of a failure, thereby minimizing revenue losses.

Disadvantages:

- The approach necessitates a sizable upfront investment and requires additional storage space on-site.

3. Leasing a GSU Transformer - $36.8M in energy and potential capacity losses plus $720,000 over 20 years ($36,000/year):

This alternative explores the feasibility of entering into a lease agreement for a GSU transformer. Leasing for units of this size is a standard approach, often entailing a reservation fee of an estimated $3,000 per month. Over a span of 20 years, which is the expected life expectancy of such units, the total cost amounts to $720,000. This translates to an annual expense of an estimated $36,000. However, leasing comes with certain conditions and restrictions:

- The owner of the leased equipment can request the unit back at any point, based on their requirements.
- Availability is not guaranteed as the unit may not be on hand when needed. An industry search and examination of the transformer strategic reserve indicated that there are currently no spare units available for lease.
- Potential capacity value and energy value impacts.

Capacity value potential loss impacts - $25.0M:

For the leasing option in the GSU project, we are assuming the occurrence of an unplanned outage at the most inopportune time, specifically a scenario where a 90-day outage spans across two MISO seasons. The outage is projected to last for 31 days in one season, with the remaining duration extending into the next season. This situation results in the loss of Zonal Resource Credits (ZRC) capacity value for two separate seasons, which, due to MISO's capacity accreditation method based on a three-year historical average, effectively doubles the amount of lost capacity value over the next three years.

Average ZRC Reduction Post-Outage:

- In the event the postulated scenario, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 236 ZRC per year for that season (based on 354 ZRCs per season).
- This scenario leads to a potential daily capacity loss of 118 ZRCs across an entire season (90 days) for each of these three years (354 ZRCs-236 ZRCs).
- For the unplanned 90-day outage spanning across two seasons assumed in this case, the 354 ZRCs will be multiplied times two to yield 708 ZRCs.

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 354 ZRCs during the first 31-day outage in one season and then for the 59-

day outage on the following season. It also adds 118 ZRCs/day applied over 90 days (full season) over the subsequent three years.

- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:
        - We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (236 in this case) and the maximum possible ZRCs of 354.
        - Multiply this difference (118) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (31,860).
        - This result is multiplied times two to account for the impacts to a second season. (63,720)
    2. Add the Immediate Loss:
        - Next, multiply the number of days the plant is offline by the total ZRCs lost (354 in this case). This gives us the immediate loss in capacity credits for the 90-day outage (31,860).
    3. Calculate the Total Revenue Loss:
        - Add the results from steps 1 and 2 to get a combined figure (95,580).
    4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)
- This leads to a total potential loss of capacity value of an estimated $25.0 million over the three-year period following the outage.

<u>Average energy value estimated loss - $11.8M:</u>

For the Covert Generating Station, under the scenario of leasing a spare GSU, there is a substantial potential loss in energy production due to an assumed 90-day outage. This loss can be quantified by considering the Net Energy Value (NEV) of the station.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $47.9M per year for the Covert Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 90-day outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($47.9M/year)/(365days/year)) x 90 days = $11.8M

Leasing option overall advantages and disadvantages:

Advantages: Leasing could offer a lower upfront cost compared to purchasing a new or spare unit outright.

Disadvantages:

- Unpredictable Availability: The availability of a leased GSU is uncertain, which can pose a significant operational risk.
- Recall Risk: There's always a possibility that the unit's owner may recall the GSU at any time, potentially causing unplanned operational downtime.
- Financial Risk: In the event of a plant shutdown due to the unavailability of a GSU, there could be a substantial financial impact.

4. Purchasing a Larger, Multi-Site GSU Transformer – Cost: $58M - $27.4M plus $30.6M in potential capacity and energy value losses:

This alternative considers purchasing a single larger spare GSU transformer that is suitable for both Zeeland Generating Station (ZGS) and Covert Generating Station (CGS). Internal economic models project the final costs to be estimated at $58M when factoring in additional expenses such as reinstallation of original overhauled GSU, modifications needed to accommodate the larger GSU at ZGS, additional outage costs and potential capacity and energy value losses. The breakdown of the internal estimate includes:

- $14M for the larger GSU transformer.
- $3M for transportation from another site and modifications needed at ZGS to accommodate bigger transformer.
- $1.25M for design and installation needs.
- $4.1M overhaul and re-installation cost of original GSU.
- $3.75M overhead estimate.
- $1.3M contingent cost to ensure compatibility with the original infrastructure. (5%)

Financial impacts:

For this option, which involves utilizing a common spare GSU for both Covert and Zeeland Generating Stations, several scenarios need to be considered to understand the financial implications fully. These scenarios vary depending on where the spare transformer is stored, and which site experiences a transformer failure. For this analysis, the worst-case scenario is assumed: the spare transformer is staged at Covert Generating Station, and a failure occurs at Zeeland Generating Station's Phase 2 transformer.

Assumptions:

For the multi-site spare option of the GSU project, the approach assumes two distinct outages, each with different implications for potential capacity value losses:

1. **First Outage - Unplanned and Single Season:**
    - The first outage, lasting 31 days, is considered unplanned and is expected to occur entirely within a single MISO season.
    - As this outage exceeds the 30-day threshold, it results in the complete loss of Zonal Resource Credits (ZRC) capacity value for that season. This loss also impacts the subsequent three years due to MISO's method of calculating capacity credits based on a three-year historical average.
    - This initial outage accounts for the period required to replace a failed GSU with the spare transformer.
2. **Second Outage - Planned and Spanning Two Seasons:**
    - The second outage, also spanning 31 days, is planned strategically to occur across the transition between two MISO seasons.
    - By dividing the outage between two seasons, each portion remains under the 30-day threshold in any single season, thereby avoiding additional ZRC capacity value penalties.
    - This outage involves reinstating the original GSU after its refurbishment, replacing the temporarily installed spare transformer.

Capacity Value Potential Losses – $17.4M

Average ZRC Reduction Post-Outage:

- In the event of a 31-day unplanned outage, the projected average Zonal Resource Credits (ZRCs) for the following three years, assuming no further outages exceeding 30 days, is expected to be around 366.7 ZRCs per year for that season (based on 550 ZRCs per season at Zeeland).
- This scenario leads to a potential daily capacity loss of 183.3 ZRCs across an entire season (90 days) for each of these three years (550 ZRCs-366.7 ZRCs).

Calculation of Total Potential Loss:

- The total potential loss of capacity value combines the immediate impact of 550 ZRCs during the first 31-day unplanned outage and the additional 183.3 ZRCs/day applied over 90 days (full season) over the subsequent three years.
- To estimate the potential capacity loss for this option:
    1. Calculate the Reduced Capacity Credits:

1. We start by finding the difference between the average number of Zonal Resource Credits (ZRCs) the plant earned over the last three years (366.7 in this case) and the maximum possible ZRCs of 550.
2. Multiply this difference (183.3) by 90 days (full season impact), and then again by 3 years. This gives us the total reduction in capacity credits over three years due to the outage (49,491).

2. Add the Immediate Loss:
    - Next, multiply the number of days the plant is offline (that season) by the total ZRCs lost in that season (550 in this case). This gives us the immediate loss in capacity credits for that outage (17,050).
3. Calculate the Total Revenue Loss:
    - Add the results from steps 1 and 2 to get a combined figure (66,541).
4. Finally, multiply this combined figure by 75% of the daily Cost of New Entry (CONE) rate, which is $261.24. (This is based on the yearly CONE rate of $127,135.)

This leads to a total estimated potential loss of capacity value of an estimated $17.4 million over the three-year period following the first unplanned outage.

For the multi-site spare option in the GSU project, the second outage is assumed to be planned to occur between MISO seasons. This careful timing ensures that the 31-day planned outage does not fall entirely within a single MISO season, thereby avoiding any loss of Zonal Resource Credits (ZRC) and potential capacity value.

<u>Average energy value estimated loss - $13.2M:</u>

For the Zeeland Generating Station, under the scenario of a multi-site spare GSU, there is a substantial potential loss in energy production due to two projected 31-day outages (62 total days). This loss can be quantified by considering the Net Energy Value (NEV) and the plant's generation capacity.

Net Energy Value (NEV): The NEV, a measure of the gross energy value minus the total costs for a particular generating station, is $77.5M per year for the Zeeland Phase 2 Station.

Calculation of Total Average Energy Loss:

- The loss in energy production is calculated over the 62-day total outage period.
- This results in a total average energy loss of an estimated $4.1 million. (($77.5M/year)/(365days/year)) x 62 days = $13.2M

This figure represents a significant potential revenue loss for the Zeeland Generating Station during the outage period.

Overall advantages and disadvantages for the multi-site spare option:

Advantages:

- **Flexibility**: A single spare unit could cater to multiple sites, potentially offering more operational flexibility.

Disadvantages:

- **Higher Costs**: The overall cost is significantly more than the initial purchase price when factoring in the additional work required.
- **Complexity**: This option could entail more logistical and operational complexities due to the constant movement and installation work.

Recommended Alternative: #2 – Purchase a spare Covert specific GSU

Option 2 emerges as the best long-term solution for ensuring a reliable spare GSU transformer at the Covert site. It eliminates dependencies on external variables and logistics that could influence the availability of the spare GSU. Additionally, the purchased unit could seamlessly be integrated as the new GSU at the location, thereby mitigating the need for multiple installations of temporary spares.

Project Benefits and Objectives:

1. **Reduction in Downtime and Financial Losses:** Opting for a dedicated spare GSU for Covert significantly reduces unit downtime in case of GSU issues or failures. This preemptive measure results in lowered financial losses during such events.
2. **Facilitation of Proactive Engineering Design and Planning:** Having a spare GSU readily available allows for easier engineering design and forward planning. This ensures that the installation of a spare or replacement GSU can be executed efficiently ahead of any emergent needs.
3. **Mitigation of Compatibility Issues:** This option mitigates potential challenges associated with installing GSUs not specifically designed for the Covert site, system, or application. It also prevents the complexities and risks of multiple installations within a short time.
4. **Revenue Recovery through Lease Agreements:** Owning a spare GSU provides Covert with the opportunity to enter lease agreements with other utilities that may require a spare, thereby enabling cost recovery over time.
5. **Addressing Increased Risk of Failure:** The oil analysis of Covert's transformers indicated the presence of chemicals for corrosive sulfur, putting them at an increased risk of failure. Having a spare GSU acts as a failsafe, ensuring continuity in operations while mitigating actions are taken.

Conclusion: Given the considerations, Option 2 proves to be strategically sound, financially prudent, and operationally efficient. It ensures reliability, provides contingency against unforeseen GSU failures, and aligns well with long-term planning objectives, making it the most favorable choice.

Scope of Work

The aim of this project is to ensure continuous operation at the Covert site by procuring and installing a spare Generator Step-Up (GSU) transformer that can be readily deployed at any GSU location within the facility.

Scope Description:

- **Procurement of Spare GSU Transformer:**
  The project entails defining the technical specifications for a compatible GSU transformer, initiating a procurement process, and ensuring quality assurance and compliance testing for the selected unit.
- **Infrastructure Development:**
  A dedicated foundation will be designed and constructed to facilitate quick installation of the transformer at any GSU location in Covert. This includes establishing a power supply and installing necessary accessories to maintain the transformer in an operational, "ready to use" condition.

Funding and Timing

- No funding has been previously committed for this project.
- No outage is required for this project.
- Desired implementation year: 2024
- Impact if the recommended implementation year is changed: Changing the recommended implementation year could lead to potential delays in addressing and mitigating the risks associated with GSU failures at the Covert site. Consequently, this may result in extended downtimes and increased financial losses, while also potentially jeopardizing the reliability of power supply from the plant.

System Engineer

- System Engineer: Keith R. Grzegorczyk

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$1,765,000**	Project engineering for Spec/RFQ/Procurement activities/Pos to secure support, Initial payment.
2025	**$25,000**	Engineering and resource needs (no payments required to SMIT)
2026	**$4,763,000**	Estimated progress payment, construction of spare GSU storage foundation, engineering, quality assurance travel.
2027	**$9,802,000**	Final payment, delivery, construction of storage foundation, closeout.

Total Cost: $16,355,000

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval, given the challenges currently faced at Zeeland Station and Covert Station and the extended lead times for transformers, now ranging from 2 to 4 years. Ensuring that our key capacity plants have a spare GSU on hand is of utmost importance.

Approvals

Title	Approver Name	Date
Generation Planning Manager John D Slinkard	DocuSigned by: John D Slinkard D640D95639854BE...	1/9/2024 | 7:55 AM EST
Director of Generation Asset Strategy Scott Hugo	DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	1/8/2024 | 9:46 AM EST
Exec Director of Electric Planning Richard T. Blumenstock	DocuSigned by: Richard T. Blumenstock C3E2F0B9920949B...	10/2024 | 9:16 AM EST
VP of Electric Grid Integration Srikanth Maddipati	DocuSigned by: Srikanth Maddipati 67DA622787D2488...	1/10/2024 | 10:00 AM EST

Concept Approval

Consumers Energy
Electric Supply
PROJECT INITIATION & CONCEPT APPROVAL

Generation Planning

Capital

Generation Type: Gas
Site: Jackson
Unit: 1 - 6
Date Created: 10/27/2022
Proposed Start Implementation Year: 2024
Project Span Whole Years: 1
Project Title: Jackson 1 - 6 Feedwater Desuperheater Valve Replacements CA
Problem Description:
The HRSG 1-6 SH Steam Desuperheater Feedwater valves have had very short life spans since original construction. There are several issues that cause the valves to wear out quickly. The valves inherently cycle frequently open and closed due to the boiler running close to HP Steam Outlet temperature setpoint at gas turbine baseload, without duct firing. This has been reduced recently by a study completed by engineering and GE to allow the HP Steam temperature to be increased from the original 750 deg F up to 770 deg F. This change did cause the valves to cycle open/close less frequently, but it did not result in a substantial improvement in valve life. The brunt of the wear is absorbed by the HP FW Autoblock valve, which when it begins to leak by, causes the SH Steam temperature to fall. The HP FW Control Valve wears out quickly as well. Typically, when this occurs the leak by accelerates quickly to the point which the manual HP FW isolation valve upstream must be closed when the unit is not duct firing in order to maintain adequate superheated steam temperature.

Alternative Solutions/Alternatives Considered

Number	Alternative	Cost	Impact
	Status Quo: Install FW control valves that have an integral lance assembly for spraying water into the steam flow	$1,615,781.58	Continued advanced degradation of valve trims due to the amount of cycling the valves encounter. $20K (parts) + $25k (labor) per valve in 2023 dollars; 3-5 valves per year. Listed cost of option is over a 7-year period (2025-2031) with a 5% annual escalation.
	Install FW control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously	622100	Separating the control valve from the spray water nozzle allows finer control of spray water at lower flows than the current integral nozzle design. This is a single lance nozzle design. Water flow will be parallel to steam flow which doesn't offer optimal atomization of the water provided by the spray nozzle.
			Separating the control valve from the spray water nozzle allows finer control of spray water which

	Install FW control valves and separate ring style spray nozzle assemblies that spray small amounts of water into steam flow continuously	$ 878,100	better at lower flows than the integral nozzle design. Design allows for control over different (higher and lower) temperature ranges as demanded by the system's needs. Multiple nozzles on a ring provides better control at lower flows than the lance design (integral or separate). Water flow will be perpendicular to steam flow which shears the steam and atomizes the water from the spray nozzles faster.

Recommended Alternative Benefits/Objectives

Recommended Alternative # Install FW control valves and separate ring style spray nozzle assemblies that spray small amounts of water into steam flow continuously
Recommended Alternative:
Why was this alternative chosen?

The basis for choosing this option (flow control valve separate from the spray water and in a circumferential ring) are:

Provides good atomization regardless of steam flow

Takes advantage of secondary atomization forces by spraying water perpendicular to steam flow

Provides sufficient penetration for maximum coverage over the cross section of the steam flow

Removes the high differential temperature due to there being a separate spray control valve

Control valve can handle high pressure drop and high rangeability without trim erosion

The traditional desuperheaters/attemperators (control valve with integral lance design) like the plant currently has, are designed for base loaded plants. In a cycling application like the plant currently operates, thermal fatigue is caused by components being at full steam temperature and then quenched by relatively cool feed water. It is ideal for the spray water control element to be separate from the attemperator nozzle so that the control element is exposed to only the variance in spray water temperature which is negligible. Desuperheaters with integral lances expose the control component variances in temperature between spray water and steam which causes the cycling that the current valves are exposed to. The lance design sprays water in the same direction as steam flow and therefore can not fully utilize secondary atomization potential, resulting in longer times required for evaporation and therefore longer distances to downstream first bend and temperature transmitter.

Project Benefits/Objectives:

Improved valve reliability (i.e., less valve replacements/swap outs)

Continuous or longer opening of flow control valves with lower attemperating flow rates but not lower temperatures

Shorter spray water evaporation time

Better atomization and at different steam flows

Scope of Work:

- Erection of scaffolding
- Removal of insulation
- Cut out 3" flange and 10" steam pipe section approximately 31" long and weld in new ring style spray nozzle assembly.
- Unhook the electrical from existing six flow control valves that are being relocated.
- Remove existing six 2" spray water control valves.
- Weld in new spray water control valves in six locations
- Rework the existing conduit and wiring to the relocated valves.
- Provide and install conduit down from the tray to the (2) new spray valve locations on all (6) units.
- Provide and install (1) 1pr#16 shielded tray cable and (1) 3c#14 tray cable from the DCS to each of the new valves.
- Pricing includes 16 hours for start-up and testing.
- NDT weld inspections
- Inservice leak testing
- Installation of new insulation
- Removal of scaffolding

Project Justification

Priority Code Title: Critical Projects
Rank: 06
Definition: These projects, if deferred will have a high likelihood of significantly impacting asset reliability in the near term. This category also includes spending to address long-standing safety issues and regulatory commitments that have some flexibility with respect to implementation.
Basis Explanation:

Deferring the project will allow the current failure and swap out rate to continue. This would be an estimated an estimated $371.5K {$198,450 (parts & labor for 4 events) and $172,800 in PSCR costs if the work is done outside of the annual planned outage}.

Economic Benefit Evaluation

	% ROR Reduction:	
x	O&M and/or PSCR Cost Changes:	$1,615,781.58 in O&M cost for parts & labor to swap out 4 per year (2025-2031); If failure events are addressed outside of the annual planned outage, the replacement power cost would be a total of $1,209,600 between 2025 and 2031 based on these assumptions ($30 LMP; 60 MW derate with unit off; 24 hours to execute work; 4 events per year)
	Changes in Periodic Factor:	
	Heat Rate Improvements:	
	Economics - Parameters for IRR Calculation:	

	Other:	

Funding and Timing

Identify funding that has already been spent or committed, if any:
Timing Impact – Is an outage required? true
Estimated Outage Duration in Days: 12
Desired implementation year: 2024
Outage Type: Site
Specify the impact if the recommended implementation year is changed:

Continued annual O&M cost for valve repairs due valve leakage

System Engineer: Cornelius Thompson Jr

Conceptual Estimate

Year	Loaded Cost	Description
2024	$ 878,100	Parts and labor to install

Total Cost: $ 878,100

Asset Strategy IRR & Justification

IRR: 20
Justification:

AS - Recommends approval of this project. This one is in the grey area on IRR, but with 3-5 failures per year this could really be considered broke fix. The IRR is 18% with the data provided. The data that is not provided that would put it over 20% is the down time and lost NEV.. with 3-5 failures per year, this would push it to be greater than 20%.

Approvers

Title	Approver Name	Approval Limit	Date
Generation Planning Manager	Cornelius Thompson Jr DocuSigned by: Cornelius Thompson Jr F6F211CF147C460...	Required	10/7/2023 10/18/2023 | 8:07 PM E
Director of Generation Asset Strategy	Scott A. Hugo DocuSigned by: Scott Hugo 31EC7A87F8F34C6...	Required	10/7/2023 10/13/2023 | 12:04 PM
Exec Director of	Richard T. Blumenstock	(> $250,000 &	10/7/2023

Electric Planning	Richard T. Blumenstock DocuSigned by: Richard T. Blumenstock C3E2F0B9920949B...	$2,000,000)	10/7/2023 10/21/2023 | 7:05 AM E

Consumers Energy Lost Capacity Calculator – Methodology & Regulatory Notes

Draft workpaper for discussion with Michigan Public Service Commission (MPSC)

Version 1.0 (2025-07-17 build)

Prepared by: Consumers Energy Generation Asset Strategy & Forecasting Teams

Contact: [insert name / email]

1. Purpose

Extended forced outages (or material derates) on generating units can reduce the accredited capacity we rely on to meet MISO Planning Reserve Margin Requirements (PRMR) and to earn capacity revenue. Because actual market outcomes (Planning Resource Auction clearing prices, bilateral forwards, accreditation rules) are uncertain and can span multiple future planning years, we use a streamlined calculator to produce a conservative, internally consistent estimate of the potential capacity value at risk when evaluating investment alternatives and responding to Michigan Public Service Commission (MPSC) data requests.

This document describes the logic in the Lost Capacity Calculator workbook supplied by the Forecasting Team, explains key inputs, shows the Excel formulas, demonstrates a worked example, and identifies the embedded conservatism that makes the results a lower-bound (60–70% view) of potential capacity losses. It is intended to accompany the calculator when provided to MPSC Staff.

2. Overview: Capacity Value Streams & What the Tool Captures

Capacity value at risk from an outage can manifest in several ways:

- Loss or reduction of Zonal Resource Credits (ZRCs) used to meet PRMR compliance.
- Reduced ability to clear ZRCs in the MISO Planning Resource Auction (PRA).
- Lower bilateral capacity revenues or increased replacement capacity purchases.
- Possible penalties / deficiency charges if PRMR not met (not modeled here).

The calculator focuses on two modeled outputs: (1) Lost Capacity in ZRCs and (2) Lost Capacity Revenue in $. It does not attempt to forecast PRA clearing prices or deficiency penalties; instead, it uses a Cost of New Entry (CONE) proxy, with an additional haircut (75% of CONE) where appropriate, to remain conservative.

3. Tool Outputs

3.1 Lost Capacity (ZRCs)

Estimates the reduction in accredited capacity attributable to the outage, expressed in ZRCs, allocated evenly across the three planning years following the Planning Year (Planning Year +1, +2, +3).

3.2 Lost Capacity Revenue ($)

Converts the ZRC impact (or, in one case, outage days) into an estimated $ value. If the outage occurs in the Planning Year being calculated and extends beyond 31 days, the model values the days past 31 at a daily CONE rate times the seasonal factor. In all other cases, the model multiplies the Lost Capacity (ZRCs) by 75% of CONE.

4. Key Inputs & Definitions

Table 1 lists the input fields referenced in the workbook and used in the formulas. Cell references (in parentheses) match the example screenshot you provided; actual cell addresses may differ in your production workbook.

Input / Variable (Excel Ref)	Definition / Notes
Unit Name (E2)	Text label only; identifies the generating unit modeled.
GVTC of Unit (MW) (E3)	Generator Verification Test Capacity (latest tested dependable MW on the GVTC basis). Denominator in the SAC/GVTC ratio: N2 = E4 ÷ E3.
Planning Year (N5)	Forecast planning year for which ZRC accreditation and resource adequacy compliance is being evaluated.
Lost Capacity (ZRCs) row 12	Formula: =IF(OR(Year=N5+1,Year=N5+2,Year=N5+3),(N4/365*N3)/3,0). Books the ZRC impact evenly across the three planning years following the Planning Year; 0 elsewhere.
Planned Capacity (ZRCs) row 11	Baseline accredited capacity with no outage. Formula copies $E$4 (SAC Value) across all year columns for comparison.
SAC Value of Unit (ZRC) (E4)	Seasonal Accredited Capacity for the Planning Year, expressed in Zonal Resource Credits. Also populates the “Planned Capacity (ZRCs)” row across all year columns (row 11).
# of MW derate (E5)	Magnitude of the outage/derate to model in MW on the GVTC basis. Enter full GVTC for a total unit outage; enter expected MW out for a partial derate. Used in N3 = E5 × N2 to convert the MW derate into accredited ZRCs impacted.
Year Being Calculated (C10 row label)	Year for which potential capacity loss is being booked in the model. May equal the Planning Year or Planning Year +1/+2/+3.
Days Offline / Derated (N4)	Outage duration in days. Used in both Lost Capacity (row 12) and Lost Capacity Revenue (row 14) formulas. Threshold: if N4 > 31 and Year = Planning Year, the Planning-Year revenue branch activates.

SAC Derate (ZRCs impacted) (N3) – Derived	Converts the outage magnitude entered in # of MW derate (E5) into accredited capacity (ZRCs) at risk using the unit's Seasonal Accredited Capacity ratio. Calculations: N2 = SAC_ZRC (E4) ÷ GVTC_MW (E3); N3 = MW_derate (E5) × N2. Interprets how many accredited ZRCs are unavailable if the specified MW are out. Full-unit outage ⇒ N3 = unit SAC (ZRCs). Because SAC is usually < GVTC, this translation from MW to ZRCs typically lowers the bookable exposure vs a raw MW × price approach (conservative).
Cost of New Entry – CONE ($/ZRC-Year) (J5)	CONE ($/ZRC-yr) (J5) – Cost of New Entry benchmark used to monetize ZRC impacts. Applied at 100% in the Planning-Year >31-day branch; discounted to 75% (0.75×CONE) in all other years to remain conservative.
Lost Capacity (ZRCs) (D12)	Model output: estimated ZRCs potentially lost due to the outage, averaged across the 3 accreditation years following the Planning Year.
Lost Capacity Revenue ($) (D14)	Model output: estimated $ value of at-risk capacity revenue, using conditional logic (Planning-Year outage >31 days vs all other cases). Formula: =IF(AND(N4>31, N5=Year), J5/365*(N4-31)*N3, LostCapZRC*0.75*J5). Uses daily CONE × days beyond 31 × ZRCs impacted for long Planning-Year outages; otherwise multiplies Lost Capacity (ZRCs) by 0.75 × CONE.

All monetary values are in nominal $ unless noted. 1 ZRC = 1 MW UCAP-Year in MISO terminology.

5. Calculation Logic

The workbook contains two principal formulas: Lost Capacity (ZRCs) and Lost Capacity Revenue ($). Both are wrapped in conditional logic that gates the calculation so we only book losses in the years affected.

5.1 Lost Capacity (ZRCs) Formula

Excel syntax:

```
=IF(OR(C20=($N$5+1),C20=($N$5+2),C20=($N$5+3)),($N$4/365*$N$3)/3,0)
```

Where:

- C20 is the year being calculated.
- $N$5 is the Planning Year (NS).

- $N$4 is Days Offline / Derated.
- $N$3 = SAC Derate (ZRCs impacted) – the number of accredited ZRCs out of service, derived as (# MW derate × SAC_ZRC ÷ GVTC_MW).

Plain-language steps:

1. Check if the year being calculated equals Planning Year +1, +2, or +3.
2. If none match, return 0 (no capacity loss booked in that year).
3. If a match, compute lost ZRCs = (Days Offline / 365) * Seasonal Factor / 3.
4. Dividing by 3 spreads the single outage's effect evenly over the three subsequent accreditation years.

Algebraic form: Lost_ZRC_perYear = ((Days_offline ÷ 365) × Seasonal_Factor) ÷ 3, conditional on Year = PlanningYear +1/+2/+3; else 0.

5.2 Lost Capacity Revenue ($) Formula

Excel syntax:

=IF(AND($N$4>31,$N$5=D20),$J$5/365*($N$4-31)*$N$3,D22*0.75*$J$5)

Where:

- $N$4 is Days Offline / Derated.
- $N$5 is Planning Year (NS).
- D20 is the year being calculated (Planning Year row).
- $J$5 is CONE ($/ZRC-Year).
- $N$3 = SAC Derate (ZRCs impacted) – accredited ZRCs affected by the outage (see Section 4)
- D22 is Lost Capacity (ZRCs) calculated above.

Plain-language steps:

1. Test if two conditions are both TRUE:

    a. Days Offline > 31.
    b. Year being calculated = Planning Year.

2. If BOTH true (Planning-Year outage >31 days):

- Compute daily CONE = CONE / 365.
- Compute Days Beyond 31 = Days Offline - 31.
- Lost Capacity Revenue = (CONE ÷ 365) × Days Beyond 31 × ZRCs impacted (This values the accredited ZRCs out during the extended outage days.).

3. ELSE (all other years / shorter Planning-Year outages):

- Lost Capacity Revenue = Lost Capacity (ZRCs) * 0.75 * CONE.

The 31-day deductible recognizes that short outages inside a Planning Year generally do not reduce the auction-accredited capacity we can count, and it avoids over-stating risk from brief events. Using only 75% of CONE in the ELSE branch is an explicit conservatism that discounts the long-run capacity value proxy.

6. Why Results Are Conservative (Lower-Bound)

Multiple structural and parametric choices bias results low relative to potential market exposure:

1. Only a 60–70% view: Seasonal factors supplied by Forecasting intentionally haircut expected ZRC exposure.
2. Accreditation conversion (SAC ÷ GVTC): We translate MW derates into accredited ZRCs using the unit's SAC/GVTC ratio. Because SAC is typically less than the tested MW capability, this step alone reduces the dollar impact vs valuing the full MW outage. Conservative.
4. Loss spread across 3 years (÷3) dilutes impact vs booking full loss up front.
4. 31-day deductible before valuing Planning-Year outages.
5. 0.75 × CONE multiplier further discounts value in ELSE case.
6. No escalation for scarcity premiums when PRA clears >CONE.
7. Excludes replacement energy purchases, RSG uplift, unit commitment effects, or penalty adders.
8. Does not model correlated fleet outages that could increase zonal tightness.

Taken together, these elements make the calculator a conservative screen; real-world financial exposure could be higher.

7. Appropriate Use Cases & Boundaries

Appropriate:

- Screening capital project justifications and comparing outage-avoidance benefits.
- Internal risk ranking across fleet assets.

Not Intended For:

- Settlements, actual PRA offer strategy, or bilateral contracting decisions.
- Recording GAAP revenues or impairment testing.
- Short-term outage scheduling optimization.

8. Revision History

Date	Version	Author	Key Changes
2025-07-17	1.0	[name]	Initial draft for MPSC discussion.

Appendix A – Detailed Input Field Definitions

Planning Year (NS): Forward compliance year used in resource adequacy planning.

Year Being Calculated: Each row in the model corresponds to a Planning Year or one of the three subsequent years.

Days Offline / Derated: Count of calendar days; if partial derate, convert to equivalent full-derate days (MW-weighted).

SAC Derate (ZRCs impacted): N3. Derived as (# MW derate × SAC_ZRC ÷ GVTC_MW). Represents the accredited capacity (ZRCs) unavailable during the modeled outage. Use full-unit MW if modeling a total outage; otherwise use the expected derated MW.

CONE: Cost of New Entry proxy. Source: Forecasting / MISO data / MPSC filings.

Appendix B – Seasonal Derate Factor Development (Summary)

Forecasting derived N3 factors by mapping historic seasonal PRA accreditation rules and expected zonal reserve margins to quarterly weighting factors. Factors are typically lower in shoulder months and higher in peak summer but always <=1.0 to maintain conservatism. Documentation available on request.

Appendix C – Sensitivity Cases

- - High Case: Replace 0.75*CONE with 1.0*CONE.
- - Peak-Summer Outage: Seasonal Factor = 1.0.
- - Short Outage: Days Offline = 20; demonstrates 31-day deductible effect.
- - Severe Outage Duration Sweep: 30/60/90/180 days.

Appendix D – FAQ for MPSC Staff

Q1. Why not use actual PRA clearing prices?
A1. Forward clearing prices are unknown; CONE provides stable benchmark; 75% haircut keeps results conservative.

Q2. Why spread across 3 years?
A2. Reflects multi-year accreditation effects and avoids double counting; aligns with internal planning horizon.

Q3. What if outage straddles two Planning Years?
A3. Use total equivalent days in each year or model two scenarios; tool is flexible.

Q4. Can Staff change the CONE multiplier?
A4. Yes; cell is unlocked; change 0.75 to 1.0 to view upper bound.

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-11C

Consumers Energy Count on Us®

Concept Approval

Jackson Generating Station Variable inlet guide vain upgrade

Date: 10/17/2024

Prepared by: Paul Ohep

Figure 1. Jackson Generating Station.

Executive Summary

The Jackson Generating Station Variable Inlet Guide Vane (VIGV) upgrade project is designed to enhance the efficiency, reliability, and operational performance of six LM6000PC gas turbines. The current fixed Inlet Guide Vanes (IGVs) limit the station's ability to optimize airflow based on varying load conditions, resulting in reduced fuel efficiency, limited power output, and an increased risk of engine stalls. By upgrading to a variable system, the project will enable the turbines to operate more efficiently across a wider range of loads, significantly improving both base load performance and overall station reliability.

Key Drivers for the Upgrade:

- **Shift from Duct Firing to Base Load**: The VIGV upgrade allows for a shift of **12 MW** from duct-fired generation to base load generation plus an increase in exhaust energy resulting in 15MW steam load for an overall base load increase of 27 MW, improving the plant's fuel efficiency and reducing reliance on less efficient duct burners. After the upgrade, the maximum output of the plant will remain **560 MWn**, but the power generation will shift from duct firing to more efficient base load capacity.
- **Improved Fuel Efficiency**: The upgrade is projected to reduce the heat rate by **189 Btu/kWh** during base load operation and 286 Btu/kWh at full duct firing operation, leading to a **2% fuel efficiency improvement at 70% power**. This translates to substantial fuel cost savings and enhanced performance across the plant's operational range.
- **Enhanced Reliability**: The VIGV system will increase the stall margin, reducing the risk of catastrophic engine stalls. This improvement in reliability will minimize the likelihood of unplanned outages and costly repairs, enhancing the station's long-term operational stability.

Economic Impact:

The financial analysis projects a **Net Present Value (NPV) of $29.609 million** in total benefits from the VIGV upgrade. This value is derived from fuel savings, increased base load generation, reduced reliance on duct firing, and the avoidance of potential repair costs due to engine stalls.

Key economic factors include:

- **Fuel Savings**: The reduction in heat rate will lead to significant cost savings in fuel consumption over the lifespan of the turbines.
- **Avoided Repair Costs**: By reducing the risk of engine stalls, the station could avoid up to **$12 million** in repair costs over the next 15 years.

Project Scope and Timeline:

- **Turbine Coverage**: The VIGV system will be installed on six LM6000PC gas turbines and completed on a spare turbine.
- **Implementation Schedule**: The installation is scheduled to occur between 2026 and 2029, aligning with planned maintenance intervals to minimize operational disruption.

Rate Case status:

This Project is included in the 2024 electric rate case.

Financial Summary

Funding Type:	Capital
Estimated Total Cost:	$3,704,350

Proposed Start Implementation Year

First year spend: 2024

Installation year: 2025-2029

Project Span Whole Years

6 Years

Problem Description

The gas turbines at Jackson Generating Station currently use fixed Inlet Guide Vanes (IGVs) that limit their ability to adapt to varying operating conditions. This results in suboptimal performance, reduced efficiency, and increased risks to turbine reliability. The following are the key challenges associated with the current system:

- **Inefficiency of Fixed IGVs**: The fixed angle of the IGVs restricts airflow modulation, preventing the turbines from operating at peak efficiency across different ambient conditions and power settings. This leads to inefficient fuel use, particularly at part load, which is common in load-following operations at Jackson Generating Station.
- **Fuel Consumption and Heat Rate**: Due to the inability of the current system to adjust for optimal airflow, the heat rate of the turbines is higher than necessary, which increases fuel consumption. The inefficiency becomes more pronounced during partial load conditions, where fuel savings are critical for economic operation.
- **Increased Risk of Engine Stall**: Without dynamic control of the IGV angles, the turbines are more susceptible to engine stalls during rapid power reductions or operational fluctuations. An engine stall can cause significant damage to the turbines, resulting in costly repairs and extended downtime.
- **Dependence on Duct Firing**: To meet power demands, the station relies on duct firing, which is less efficient, consumes more fuel, and places additional stress on the system. This dependency results in higher operational costs and increased emissions.

Project Objective

To address these issues, the Jackson LM1-6 Variable Inlet Guide Vane (VIGV) upgrade will replace the fixed IGVs with a variable system, enabling dynamic airflow modulation. This upgrade will:

- **Increase Base Load Output**: The VIGV system will enhance the base load capacity of the gas turbines by 12 MW and contribute to a total site-wide increase of 27 MW when combined with steam turbine improvements. This increase will reduce the reliance on inefficient duct firing.
- **Improve Fuel Efficiency**: The upgrade will improve the baseload heat rate by approximately 189 Btu/kWh (without duct firing) and 286 Btu/kWh (with duct firing).
- **Enhance Stall Margin**: By allowing better airflow control, the VIGV system will improve the stall margin, reducing the risk of turbine failure during rapid load changes and ensuring more reliable operation.

This project is critical for improving the overall performance and efficiency of the turbines, reducing operational costs, and minimizing the risk of unplanned outages due to engine stalls.

Alternative Solutions/Alternatives Considered

1. Do Nothing – Cost: $29.6 million ($29.6M of unrealized value to our customers)

In the "Do Nothing" scenario, Jackson Generating Station would continue to operate with its current fixed Inlet Guide Vane (IGV) system, foregoing the implementation of the Variable Inlet Guide Vane (VIGV) upgrade on the six LM6000PC gas turbines. The consequence of not upgrading the IGV system is the loss of significant operational improvements that would otherwise be realized in efficiency, power output, and reliability. Below is a detailed analysis of the impacts and missed opportunities if the VIGV upgrade is not implemented:

Missed Incremental Power Output

- **Shift from Duct Firing to Base Load**: Without the VIGV upgrade, the station will miss the opportunity to shift **12 MW of capacity** from duct firing to base load generation. The VIGV upgrade does not increase the overall maximum output of the plant but redistributes capacity more efficiently. Currently, with duct burners on, the station reaches a peak output of **546.57 MWn**. With the VIGV upgrade, the plant would be capable of **560 MWn** under the same duct burner conditions, while limiting output to the interconnect constraint during cooler weather by reducing duct burner flow.
- **Improved Base Load Efficiency**: The expected gain of **13.4 MW in base load** would be realized without relying on duct firing, thus increasing the efficiency of base generation. This means that the station would achieve the same overall power output but with a shift of capacity from less efficient duct-fired generation to more efficient base load operation. Without the upgrade, the station will remain dependent on duct firing to achieve higher outputs, losing out on this improved operational profile.

Fuel Efficiency Improvement Missed

- **No Heat Rate Reduction**: Without the upgrade, the station will continue to operate with a heat rate of **8,004 Btu/kWh (LHV)** for each LM6000PC turbine during base load operations. The VIGV upgrade would have reduced this heat rate to **7,958 Btu/kWh (LHV)**, leading to more efficient fuel usage and cost savings.

The following table summarizes the increase in generation and heat rate impacts with and without VIGV:

VIGV	Duct Burner	LM6000 kWg	GT HR LHV Btu/kWh	MWn	NUHR Btu/kWh	ΔMW	ΔNUHR Btu/kWh
No	Yes	47,321	8,004	546.57	8,928		
Yes	Yes	49,958	7,974	560.00	8,642	13.43	286
No	No	47,321	8,004	427.45	7,951		
Yes	No	50,063	7,958	454.71	7,761	27.26	189

By not upgrading, the plant misses a significant MW improvement in output at lower heat rates without duct burners, and a considerable heat rate improvement of **189 Btu/kWh** across the entire load range. This represents a significant loss in fuel savings and operational efficiency over time.

Increased Risk of Engine Stalls and Repair Costs

- **Stall Risk**: The existing fixed IGV system increases the risk of engine stalls, particularly during rapid load reductions. An engine stall is a critical failure that can lead to catastrophic damage, requiring costly repairs. The estimated cost of an engine stall repair is up to **$4 million per turbine**, with an average stall probability of **one occurrence every five years**. Over the next 15 years, this could result in up to **$12 million** in repair costs that could have been mitigated by the VIGV system.

Economic Losses

The total economic impact of not implementing the VIGV upgrade can be summarized as follows:

- **Value Loss**: The total projected value of the VIGV upgrade, including improved heat rates, increased base load capacity, and reduced reliance on duct firing, has been calculated at **$29.609 million**. By not proceeding with the upgrade, this value will be lost.

Below is a summary of the results from the Aurora economic model used to calculate the economic impact of this upgrade until 2040:

Net Present Value Results	VIGV
Current Nameplate Capacity (MW)	547
Incremental Energy, NPV(K$)	$26,781
Incremental Operating Costs, NPV (K$)	$7,921
Investment Cost, NPV (K$)	($5,093)
Total Value of VIGV Upgrade (K$)	**$29,609**

Table 1. Summary of Aurora model results listing economic impacts of the VIGV upgrade.

By not implementing the VIGV upgrade, Jackson Generating Station will forfeit key operational improvements, including enhanced efficiency, greater base load capacity, and reduced maintenance risks. This "Do Nothing" scenario results in higher operational costs, increased reliance on less efficient duct firing, and greater exposure to potential repair costs from engine stalls.

2. Upgrade gas turbines to Variable inlet guide vane systems -$3.7 Million

Following the analysis of the "Do Nothing" scenario, it is recommended to proceed with the installation of the Variable Inlet Guide Vane (VIGV) system on the six LM6000PC gas turbines at Jackson Generating Station. This upgrade offers clear operational benefits by enabling a shift in capacity from duct firing to base load generation, improving overall efficiency, and reducing operational costs. Below is a picture of the VIGV assembly.

Variable Inlet Guide Vanes Assembly

Scope of the Upgrade:

- **Turbine Coverage**: The VIGV system will be installed on six LM6000PC gas turbines (S/Ns: 191306, 191307, 191312, 191339, 191345, 191351) and completed on the spare engine (S/N: 185132).
- **Installation Schedule**: The work will be scheduled during the turbines' planned maintenance intervals between 2026 and 2029, ensuring minimal impact on normal operations.

Key Benefits of the Upgrade:

- **Capacity Shift**: The primary benefit of the VIGV upgrade is the shift of **13.4 MW** from duct-fired capacity to base load generation. This does not increase the total site output but redistributes capacity more efficiently, improving the station's ability to generate power without relying on duct burners. After the upgrade, the maximum output will remain **560 MWn**, but with reduced dependence on less efficient duct burners.
- **Efficiency Gains**: The upgrade will result in a **189 Btu/kWh heat rate reduction** during base load operations, leading to significant fuel savings.
- **Increased Reliability**: The upgrade will also mitigate the risk of engine stalls by improving the stall margin, thereby reducing the likelihood of costly repairs and unplanned outages. This provides operational stability and long-term cost savings.

Economic Justification:

The economic value of the upgrade has been assessed at **$29.609 million**, considering the efficiency gains, improved base load performance, and avoided repair costs. These benefits will result in long-term fuel savings, enhanced revenue from optimized power generation, and reduced maintenance expenses.

For a full breakdown of the economic analysis, please refer to the preceding section.

Conclusion:

Implementing the VIGV upgrade is the most effective option to enhance the efficiency and reliability of Jackson Generating Station. It optimizes the station's capacity by shifting power generation from duct firing to base load, while reducing operational costs and increasing reliability. The upgrade ensures that the station can meet its future energy needs with improved efficiency and reduced risk of costly repairs.

Funding and Timing

- No funding has been previously committed for this project.
- No outage is required for this project.
- Desired implementation year: First year spend 2024, 2029 final install and spend year.
- Impact if the recommended implementation year is changed:

  If the recommended implementation years for the VIGV upgrade are changed, the project would face several potential negative impacts. Delaying the upgrade could result in missing planned maintenance intervals, leading to increased costs for additional engine swaps outside of these windows. Additionally, the station would continue to operate with less efficiency and higher fuel consumption during the delay, losing out on the projected fuel savings and incremental power gains. Furthermore, the risk of engine stalls would remain elevated, increasing the likelihood of costly unplanned repairs during the extended period without the upgrade.

System Engineer

- System Engineer: Joseph Brooks

Conceptual Estimate

Year	Loaded Cost	Description
2024	**$120,900**	Request for Purchase work, Engineering work, Initial PO creation, Computer hardware & configuration, software design work.
2025	**$970,840**	Milestone payment, Engineering work.
2026	**$1,046,370**	Installation of VIGV upgrade on first two engines 185132, 191307
2027	**$1,107,600**	Installation of VIGV upgrade on next two engines 191345, 191312
2028	**$305,760**	Installation of VIGV upgrade on next two engines 191351, 191306
2029	**$152,880**	Installation of VIGV upgrade on final engine 191339, closeout

Total Cost: $3,704,350

Asset Strategy Approval Comments

The Asset Strategy Group strongly recommends approval based on economic analysis.

Approvals

Title	Approver Name	Date
Generation Planning Manager		
Director of Generation Asset Strategy		
Exec Director of Electric Supply Engineering		
VP of Electric Supply		

Question:

20. Refer to Company filing attachment 131 regarding the "(13475) JGS - LM1-6 VIGV (variable inlet guide vane)" project.

a. Please describe why the project's spending is higher than what was initially approved in the last rate case (U-21585), including any documentation of these cost increases and their causes.

b. Confirm that there are no other documents that support this project.

i. If confirmed, please identify the other sources of documentation.

ii. If not confirmed, please provide supporting documentation that has not already been provided.

Response:

a. The project remains within the total forecasted budget and is progressing as planned. As outlined in response attachment U-21870-MNSC-CE-0072_0004, this is a multi-year initiative involving upgrades to all seven LM6000 units at the Jackson facility. In rate case U-21585, the figures presented pertained exclusively to the bridge and test years. The full scope of the upgrade extends beyond that period and is being executed in a phased rotation across all units. Funding allocated in 2024 and 2025 was designated for contract commitments necessary to initiate the project. The table below shows the installation schedule and associated cost forecast through project completion. This schedule reflects a deliberate and efficient rotation strategy to minimize operational disruption while ensuring all LM6000 units receive the necessary upgrades.

	2024	2025	2026	2027	2028	2029
Cost	$120,900	$970,840	$1,046,370	$1,107,600	$305,760	$152,880
Units Completed	-	-	2	2	2	1

b. Confirmed.

Witness: RICHARD T. BLUMENSTOCK
Date: August 14, 2025

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-14C

Caroline Palmer, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-973-1715
cpalmer@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge, MA. *Principal Associate*, June 2024 – present.

- Conduct analysis and provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings, on topics including electric utility class cost of service, revenue allocation, advanced rate design, avoided cost methodology, and distributed generation interconnection and planning.

Strategen Consulting, Oakland, CA. *Senior Manager*, 2024; *Manager,* 2023 - 2024; *Senior Consultant*, 2021 - 2022; *Consultant*, 2019 - 2021.

- Conducted analysis and provided expert witness and consulting services to state regulatory commissions, state consumer advocates, and non-profits to advance the public interest in regulatory decision-making around electricity service, pricing, and decarbonization.

Metropolitan Area Planning Council Boston, MA. *Clean Energy Fellow*, 2017.

- Provided technical assistance to Massachusetts local government on renewable energy technology and energy planning.

Fulbright Foundation Athens, Greece. *Fulbright Research Fellow*, 2015 – 2016.

- Designed and conducted original, independent research on renewable energy policymaking and implementation in the context of Greece's severe economic crisis

Meister Consultants Group (now Cadmus), Boston, MA. *Analyst,* 2014 – 2015.

- Performed research and writing for renewable energy policy design, analysis, and implementation.

EDUCATION

University of California, Berkley, CA
Master of Public Policy – Energy Policy, 2019

Georgetown University, Washington, DC
Bachelor of Science in Foreign Service – Science, Technology, and International Affairs, 2013

TESTIMONY

Connecticut Public Utilities Regulatory Authority (24-10-04) Direct Testimony, Surrebuttal Testimony, and Cross-examination of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Application of The United Illuminating Company to Amend Its Rate Schedules. On behalf of The Office of Consumer Counsel. February 13, 2025, March 24, 2025, and May 6, 2025.

New Hampshire Public Utilities Commission (DE 24-070) Direct Testimony and Cross-examination of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Public Service Company of New Hampshire d/b/a Eversource Energy Request for Change in Distribution Rates. On behalf of the NH Office of Consumer Advocate. January 23, 2025 and June 4, 2025.

Massachusetts Department of Public Utilities (D.P.U. 24-195 D.P.U. 24-197) Direct and Surrebuttal Testimonies of Caroline Palmer and Thanh Nguyen addressing the EV Infrastructure Program mid-term modification filings from the electric distribution companies. On behalf of The Office of the Attorney General. April 4, 2025 and May 27 2025.

Missouri Public Service Commission (WR-2024-0320). Direct Testimony of Caroline Palmer (Cost-of-Service Study/Rate Design) regarding Missouri-American Water Company's Request for Authority to Implement a General Rate Increase for Water and Sewer Service. On behalf of Consumers Council of Missouri. December 20, 2024.

Missouri Public Service Commission (ER-2024-0319). Direct Testimonies and Surrebuttal Testimony of Caroline Palmer (Revenue Requirement and Cost-of-Service Study/Rate Design) regarding Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service. On behalf of Consumers Council of Missouri. December 3, 2024, December 17, 2024, and February 14, 2025.

Nova Scotia Utility and Review Board (M11874). Direct Testimony of Caroline Palmer regarding costs incurred to implement the Renewable to Retail market. On behalf of Counsel to Nova Scotia Utility and Review Board. November 1, 2024.

Maine Public Utilities Commission (Docket No. 2024-00137). Direct Testimony and Cross-examination of Caroline Palmer and Eric Borden regarding Stranded Cost Rate Design. On behalf of the Maine Office of the Public Advocate. October 1, 2024 and January 10, 2025.

New York Public Service Commission (Cases 24-E-0322 & 24-G-0323): Direct Testimony of Caroline Palmer, Melissa Whited, and Ben Havumaki regarding the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service. On behalf of the Utility Intervention Unit (UIU) of the New York Department of State's Division of Consumer Protection. September 26, 2024.

Massachusetts Department of Public Utilities (D.P.U. 23-150): Direct Testimony, Surrebuttal Testimony, and Cross-examination of Caroline Palmer and Ron Nelson regarding Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a

Performance-Based Ratemaking Plan. On behalf of the Massachusetts Office of the Attorney General. March 29, 2024, May 3, 2024, and May 20, 2024.

North Carolina Utilities Commission (Docket No. E-7, Sub 1276): Direct Testimony of Caroline Palmer regarding the Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation. On behalf of the North Carolina Attorney General's Office. July 19, 2023.

Oklahoma Corporation Commission (Case No. PUD 2022-000093.): Adoption of Direct Testimony and Cross-examination regarding the Application of Public Service Company of Oklahoma, for an adjustment in its rates and charges and the electric service rules, regulations, and conditions of service for electric service in the state of Oklahoma and to approve a formula-based rate proposal. On behalf of AARP. May 22, 2023.

Maine Public Utilities Commission (Case No. 2022-00152): Direct Testimony and Surrebuttal Testimony of Caroline Palmer, Nikhil Balakumar, and Ron Nelson regarding the Central Maine Power Company's request for Approval of a Rate Change - 307 (7/30/23). On behalf of the Maine Governor's Energy Office. December 2, 2022 and April 6, 2023.

Massachusetts Department of Public Utilities (D.P.U. 21-91): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and EV Demand Charge Alternative Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

Massachusetts Department of Public Utilities (D.P.U. 21-90): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III EV Market Development Program and EV Demand Charge Alternative Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

Massachusetts Department of Public Utilities (D.P.U. 21-92): Direct Testimony and Cross-examination of Caroline Palmer and Ron Nelson regarding the Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its EV Infrastructure Program, EV Demand Charge Alternative Proposal, and Residential EV Time-of-Use Rate Proposal. On behalf of the Massachusetts Office of the Attorney General. January 5, 2022, and March 22, 2022.

PUBLICATIONS

Yuang, C., M. Whited, T. Nguyen, S. Schadler, R. Anderson, W. Dejeanlouis, C. Palmer, C. Mattioda, A. Glaser Schoff, S. Koester, J. Hittinger, P. Eash-Gates. 2024. *Utility Engagement Playbook for Industrial Customers: Addressing Power Sector Barriers to Electrification.* Synapse Energy Economics and World Wildlife Fund for Renewable Thermal Collaborative.

Palmer, C. 2019. *Using Low Carbon Fuel Standard Proceeds from EV Adoption to Improve the Efficiency of Electricity Rates.* Berkeley Public Policy Journal.

PRESENTATIONS

Palmer, C. 2022. Utility Transportation Electrification from a Consumer Advocate Perspective. NASUCA Mid-Year Meeting. Indianapolis, IN.

Palmer, C. 2017. Integration of renewable energy in Greek energy markets: A case study. 2nd HAEE International Conference. Athens, Greece.

Resume last updated June 2025

U21870-MNSC-CE-0221 (Partial)
Page **1** of **1**

Question:

15. Refer to Davis Direct Testimony p.7, footnote 1 stating: "Meter facilities…are assigned using allocators based on the number of customers."

a. Describe in detail the extent of advanced metering infrastructure (AMI)installations in the Company's territory. What portion of each customer class has AMI installations? If the answer is less than 100%, explain if the Company plans to roll out advanced metering to all customers, and provide the timeline for the rollout.

b. Confirm that the Company classifies advanced metering infrastructure as customer-related and allocates AMI costs using allocator 170, or weighted customer.

c. Of the Company's $818,321,000 metering equipment plant in service, how much is AMI?

d. Provide the docket number(s) and Commission order(s) approving the Company's AMI investment.

e. In Case No. U-15645 (Remand), Witness Schonhard provided the Company's Smart Grid/AMI business case analysis, which had been updated in the summer of 2013 (Exhibit A-2 (DES-1), Summary of Business Case Costs and Benefits 2007-2032). Please provide the Company's most recent Smart Grid/AMI business case analysis, the docket number in which it was provided, and any testimony accompanying the filling.

Response:

> **<u>Objection of Counsel:</u> Consumers Energy Company objects to parts d. and e. of this discovery request on the grounds that it seeks information in the possession of, known to, or otherwise equally available to the requesting party. Subject to the Company's objection, and without waiving its objection, the Company responds as follows:**

b. Correct

c. To break out test year distribution plant into FERC account detail the COSS relies on historic FERC account balances including FERC 370 (meter plant in service). In 2023 AMI meters made up 68% of the total balance in FERC 370.

d. The Commission approved the Company moving from the AMI pilot to full deployment in Case No. U-16794. The Commission has approved recovery of AMI investment in every Consumers Energy electric rate case thereafter.

e. The Company last filed an AMI business case in Case No. U-21389 which was sponsored by Company witness Jason Coker. Updated AMI metrics in the current case can be found in Exhibit A-133 (MPK-23).

Witness: Emily A. Davis
Date: August 18, 2025

U21870-MNSC-CE-0221 (Partial)
Page **1** of **1**

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Response:

a. The numbers of residential, commercial, and industrial customers who have AMI meters, and the numbers who have non-AMI meters, are shown below, based on the Company's 2024 EIA-861 filing which is reported out by the U.S. Energy Information Administration at https://www.eia.gov/electricity/data/eia861/

	Residential	Commercial	Industrial
Number of AMI Meters	1,660,920	233,245	148
% with AMI Meters	99.48%	98.46%	9.91%
Number of non-AMI Meters	8,661	3,654	1,345
% with non-AMI Meters	0.52%	1.54%	90.09%

To the extent that customers do not have AMI meters, it is because they have either a) opted out of receiving AMI; or b) are on a rate that makes them ineligible for AMI. The latter classification is particularly relevant for customers with MV90 accounts and meters. The Company does not plan to roll AMI out to these customers.

Witness: MICHAEL P. KELLY
Date: August 18, 2025

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Page **1** of **2**

Question:

16. Refer to Exhibit A-129 (MPK-19), p. 34 describing "Bi-directional power flows, especially in circuits that show a propensity to higher-than average adoption of solar DG" and p.142, stating "A centralized DERMS is critical for managing bi-directional power flows."

a. Describe in detail the extent of bi-directional power flows on the Company's distribution system. Provide all supporting information demonstrating the existence of bi-directional power flows on the Company's distribution system.

b. When bi-directional power flow occurs, does it flow from lower-voltage distribution equipment to higher-voltage distribution equipment? If yes, please explain if this is a phenomenon that the Company considers "critical" to manage, and why.

c. When bi-directional power flow occurs, does it flow from distribution-level equipment onto transmission-level equipment? If yes, please explain if this is a phenomenon that the Company considers "critical" to manage, and why.

Response:

a. The referenced bullet points on p. 34 of Exhibit A-129 (MPK-19) indicate indirect challenges associated with customer technology adoption that the Company will have to address, including but not limited to bi-directional power flows and power quality issues. The Company must consider these issues to ensure any impact to the grid and the customers it serves are proactively mitigated. The ability to produce reports demonstrating the extent of bi-directional power flow on the distribution system are expected to be developed as part of this effort but are not available at present.
   At minimum, analysis demonstrating the extent of bi-directional flow introduced by Level 1 through Level 5 interconnections throughout the Company's distribution system will require:
   - Processing of hourly AMI and/or event data to capture the extent of customer exports to the secondary system
   - Processing of hourly line device data to capture the extent of reverse flow through primary distribution lines and devices
   - Processing of hourly substation device data to capture the extent of reverse flow through substation devices

   While many modern electronic controls used for line and substation equipment may be capable of measuring both the magnitude and direction of active and reactive power flow, there are additional limitations to overcome:

   - Not all distribution devices are equipped with these modern controls
   - Not all controls are configured to measure and report this information back to enterprise systems
   - The overall deployment density of electronically controlled devices is insufficient to fully assess bi-directional power flow across the system

   To provide the Company's planners and operators with full, system-wide visibility into the direct and indirect challenges associated with customer adoption of new technologies, enhanced power

flow simulation capabilities are required. The Load Flow Tool Upgrade described in Company witness McPhail's testimony is critical to the Company's plans to enable these capabilities and datasets within the CYME distribution planning software. Similar enhancements to real-time operational systems will need to be made to provide the same level of visibility to operators as DER penetration increases.

b. When bi-directional power flow occurs, it flows in a direction opposite traditional power flows on a radial distribution circuit. Traditional flows emanate at the circuit source (substation), following a radial path through utility-owned conductors and devices (regulators, reclosers, isolators, fuses, switches, transformers, etc.) to reach customer loads. Bi-directional flow typically occurs in the reverse direction and may include flowing from lower-voltage distribution equipment to higher-voltage distribution equipment.

   Whether bi-directional flow occurs from lower to higher voltage is not the sole determinant of criticality for anticipated future DER management requirements. As DER penetration increases, the Company does consider it critical, and remains ultimately responsible for:

   1. Ensuring that customers receive the energy they need, when they need it, which can only be accomplished by knowing what the load is, and what sources of generation will serve it.
   2. Ensuring the safety of the public and Company employees by having full visibility and the ability to manage the power flow directionality and energization status of all Company-owned assets at all times.
   3. Ensuring that the Company is delivering adequate power quality to customers' homes and businesses. Common power quality issues associated with reverse flow or exports from customer owned generation/storage include voltage rise at the point of common coupling, voltage unbalance, delayed or mis-operations of voltage conditioning devices, and harmonics.
   4. Ensuring that power flows in either direction do not exceed the forward or reverse thermal ratings of Company owned equipment, to maintain the reliability of service for all customers on the circuit.
   5. Ensuring that protective device schemes and settings account for the magnitude and direction of power flows so they operate as expected when faults on the system occur.
   6. Ensuring that the intermittency of solar and other sources of renewable generation do not lead to premature wear or reduced life-expectancy of Company-owned equipment.
   7. Ensuring that automated or manual load transfer schemes have full visibility of the load and generation present on the system at the time of transfer. Relying on third-party/customer owned sources of generation introduces many new contingencies, including but not limited to inverter settings that are not what they were at the time of commissioning, and third-party/customer owned equipment that has gone offline without notification to the Company.

c. Yes, there could be times when power flows from distribution-level equipment to transmission-level equipment. The Company needs to maintain awareness and the ability to control reverse flow to transmission as this involves an interconnection with another entity.

Witness: Scott McPhail
Date: August 18, 2025

U21870-MNSC-CE-0214
Page **1** of **1**

Question:

8. Refer to Davis Direct Testimony p.11.

a. Explain why the Company categorizes distribution batteries as low voltage distribution (LVD) Voltage 3. Provide references to the Company's work orders, distribution planning manual, or other distribution engineering literature to indicate that the batteries serve only Voltage 3 and 4 customers.

b. In live, unlocked Excel file format with all links and formula intact, provide all analysis the Company has conducted to conclude that it is appropriate to categorize distribution batteries as LVD Voltage 3.

Response:

a. The EAC categorizes distribution batteries by their connected voltage. The batteries currently in service are connected between voltages 8.32-24.9 kV which is considered LVD Voltage level 3.

I am not aware of any engineering literature or manuals that specifically state batteries only serve Voltage 3 and 4 customers. The COSS treats this distribution-related battery plant, which is deployed to support the electric distribution system (e.g., capacity deferral, voltage support, resiliency, etc.), the same way it treats other demand-related distribution plant and allocates costs to the customer classes connected to (or downstream of) the voltage level of that equipment. The Commission approved this battery treatment in Case No. U-21389.

b. See the response to subpart a.

Witness: Emily A. Davis
Date: August 15, 2025

U21870-MNSC-CE-0253
Page **1** of **1**

Question:

9. Refer to the Direct Testimony of Laura M. Connolly p.11.

a. Narratively describe in detail how the Company would calculate the facilities allowance, including how the Company would determine the net present value of margin for expected load over five years of the contract term.

b. Does the Company propose to include any non-energy-related power supply revenues in its calculation of the facilities allowance? If yes, identify all nonenergy-related power supply revenues to be included in the facilities allowance.

c. Identify the specific facilities costs that the facilities allowance would offset.

d. Explain how the facilities allowance would interact with the charges specified in the Rate LED tariff or contract.

e. In live, unlocked Excel file format with all links and formula intact, provide an example calculation for the facilities allowance based on the net present value of margin, based on expected load over five years of the contract term. Clearly identify all assumptions used to produce the example calculation and all steps involved in the calculation. Demonstrate how the calculated facilities allowance would interact with the charges specified in the Rate LED tariff or contract.

Response:

a. The Company would calculate the expected annual system contribution revenue and distribution revenue. The Company would then calculate the NPV of each annual revenue amount based on a 7.45% minimum acceptable rate. The total of each annual NPV of marginal revenue would set the allowance offered to the customer. The total allowance would be based on five years of NPV revenue.

b. No.

c. The specific costs will vary based on the customer and the site but could include items like dedicated substation, transformers, and wires needed to serve the specific customers site.

d. The calculation of the incremental distribution charge would be decreased by the amount offered to the customer as facilities allowance.

e. Please see the attached example calculation based on a hypothetical 35 MW customer with a 90% load factor. The proposed facilities allowance calculation would yield a total allowance of $2.1 million. This $2.1 million would be used to offset the incremental distribution costs used to calculate the incremental distribution charge.

Witness: Laura M. Connolly
Date: August 21, 2025

Consumers Energy Company
Example facilities allowance calculation at 35 MW, 90% Load Factor
Large Economic Development Rate LED VL 1
($ in millions)

Description		Years: 1	2	3	4	5	Sum
Power Supply							
System Contribution	$mils	0.1	0.1	0.1	0.1	0.1	0.4
Quantity	GWh	277	277	277	277	277	1,383
Rate	$ per kWh	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Delivery							
Maximum Demand	$mils	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 2.1
Quantity	MW	420	420	420	420	420	2,100
Rate	$ per kW	1.02	1.02	1.02	1.02	1.02	1.02
Total Annual Expense	$mils	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 2.5
NPV of Marginal Revenue	$mils	$ 0.5	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 2.1

Minimum Acceptable Rate 7.45%

U21870-MNSC-CE-0255
Page **1** of **1**

Question:

11. Refer to Connolly Direct Testimony and Consumers' electric rate book.

a. Describe how the Company calculates the incremental transmission charges applicable to the load served under Rate LED.

b. In live, unlocked Excel file format with all links and formula intact, provide all workpapers, calculations, and original data that underlie the calculation described in part (a).

c. Explain how the Company collects the costs of service drops, metering, and distribution transformers for Rate LED customers. Explain if the charge is a per customer per month charge, or something else. If not a per customer per month charge, explain why not.

d. Explain what costs the Company collects through the Rate LED System Contribution Charge and how the Company calculates the charge. In live, unlocked Excel file format with all links and formula intact, provide all workpapers, calculations, and original data that underlie the calculation of the System Contribution Charge.

Response:

a. The incremental transmission charge was established in Case No. U-21160. The approved LEDR transmission charge was calculated by imputing what METC's total transmission cost is based on Consumers share of the total METC load and assumes Rate LED customers are responsible for the increase in Consumers share from serving the Rate LED load.

b. See attached file, Estimated Share of Assigned Transmission.xlsx.

c. The costs related to service drops, metering, and distribution transformers would be included as part of the calculation of the incremental distribution facilities charge. This is charged as a per kW charge and levelized over the life of the contract.

d. The System Contribution charge was established in Case No. U-21160 and was set based on 1% of the Rate GPD embedded capacity costs. See the attached file, LEDR System Contribution Charge.xlsx.

Witness: Laura M. Connolly
Date: August 21, 2025

U21870-MNSC-CE-0256
Page **1** of **2**

Question:

12. Refer to Connolly Direct Testimony and Consumers' electric rate book, which states that the "Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution," and that this charge "is fixed for the contract term at the rate in effect at the time of contract execution,"

a. Explain why it is reasonable to maintain a fixed Production Charge for the contract term at the rate in effect at the time of contract execution.

b. If MISO's Cost of New Entry (CONE) for Zone 7 increases in the future, please explain whether the cost to the Company to procure capacity on behalf of Rate LED customers would also increase. If not, please explain why not.

c. Please explain whether maintaining a fixed Production Charge for the duration of the contract could result in costs being shifted to other customers.

d. Explain in detail how the Company procures energy and capacity for Rate LED customers. In your response, please address whether capacity will be procured through the wholesale market, through bilateral contracts, through utility self-build, or through some other method, and the duration of any contracts.

e. Please explain whether the Company's rates for Rate LED provide sufficient revenue to cover the full embedded cost of service associated with serving Rate LED customers. If not, please explain why not.

f. Please explain whether the Company's rates for Rate LED would provide any contribution to margin, or whether they would only cover marginal costs. If they would only cover marginal costs, please discuss whether this is reasonable and in accordance with standard ratemaking practices.

g. Please provide the Company's most recent estimate of the marginal cost associated with energy, generation capacity, transmission capacity, and distribution capacity. To the extent available, please provide these marginal costs in the most granular resolution available, such as hourly energy costs or seasonal capacity costs. Please also provide these costs in Excel format.

Response:

a. The production charge is based on the marginal cost of capacity associated with serving new load. In Case No. U-21160, the MPSC approved locking the production charge in for the term of the contract.

b. The Company is proposing to update the production charge based on the latest CONE forecast in each electric rate case. Any incremental new load will pay the production charge approved at the time their contract is signed.

c. The MPSC found in its order in Case No. U-21160 that the proposed Rate LED complies with Michigan law and would not increase the cost of service for any customer.

d. The Company anticipates a mix of renewable resources, energy producing resources and firm capacity resources will be needed to serve future Large Economic Development customers. The specific amounts and resource types will be presented in the company's applicable integrated resource plan filings.

e. Rate LED is based on the marginal cost of serving new qualifying load. The design was approved by the MPSC in Case No. U-21160.

f. The System Contribution charge approved as part of Rate LED is designed to cover a portion of embedded costs of capacity.

g. The Company has not analyzed this information. The Company has only reviewed the latest marginal cost of capacity in relation to the latest forecast of CONE in order to update the production capacity charge as part of Rate LED.

Witness: Laura M. Connolly
Date: August 25, 2025

U21870-MNSC-CE-0257
Page **1** of **1**

Question:

13. Refer to Exhibit A-16 (BAG-2) Schedule F-5 p.65.

a. Why does the Company propose to specify the facilities allowance in the Rate LED contract for electric service rather than in the tariff?

b. Provide the language that will be specified in the Rate LED contract for electric service regarding the proposed facilities allowance. If the contract language will not be the same for all Rate LED customers, explain all ways in which the facilities allowance provision could differ between customers.

c. Will the Company submit the Rate LED contract, or the proposed facilities allowance, to the Commission for approval?

d. Will the Company allow any current Rate LED customers to utilize the facilities allowance? If yes, describe the applicability of the facilities allowance to such customers.

Response:

a. Exhibit A-16 (BAG-2) page 65 of 81 specifies that a facilities allowance will be applicable to Rate LED.

b. The Company has not drafted this contract language yet but expects the language would be consistent for all Rate LED customers.

c. No.

The Company believes the facilities allowance should apply to existing Rate LED customers if approved. The applicable facilities allowance would be calculated and applied to the existing customer's incremental facilities charge. The facilities allowance would be an offset to the incremental distribution investment and the incremental facilities charge would be recalculated for the remaining term of the contract to reflect the adjustment for the allowance.

Witness: Laura M. Connolly
Date: August 25, 2025

Question:

9. Refer to Davis Direct Testimony p.15-16.

a. Do any customer classes besides the residential class have access to the MIMO 3.0 tool?

b. In live, unlocked Excel file format with all links and formula intact, provide the number of customers in each customer class that has multiple accounts. Separately, also provide the number of customers in each customer class that has a Multi-Account Online Account Management login for multiple accounts.

c. Identify the allocation schedule (ie, allocator name/number) that the Company proposes using to allocate MAOAM costs if the Commission no longer requires a separate breakout of costs for this project.

d. Identify the allocation schedule (ie, allocator name/number) that the Company would use to allocate MAOAM costs if the Commission continues to require a separate breakout of costs for this project.

Response:

c. 502: Total Labor
d. 502: Total Labor

Witness: Emily A. Davis
Date: August 15, 2025

Question:

9. Refer to Davis Direct Testimony p.15-16.

a. Do any customer classes besides the residential class have access to the MIMO 3.0 tool?

b. In live, unlocked Excel file format with all links and formula intact, provide the number of customers in each customer class that has multiple accounts. Separately, also provide the number of customers in each customer class that has a Multi-Account Online Account Management login for multiple accounts.

c. Identify the allocation schedule (ie, allocator name/number) that the Company proposes using to allocate MAOAM costs if the Commission no longer requires a separate breakout of costs for this project.

d. Identify the allocation schedule (ie, allocator name/number) that the Company would use to allocate MAOAM costs if the Commission continues to require a separate breakout of costs for this project.

Response:

a. Currently, only residential accounts have access to MIMO.

b. Please see U21879-MNSC-CE-0215-Byrom_ATT 1, lines 1-4 for the requested customer numbers.

   Currently, there are no Customers with Multi-Account Online Account Management login for multiple accounts as the tool is still in development. However, the Companies C&I customers have access/use the current tool, BillTrust, for their multiple account management. Please see U21879-MNSC-CE-0215-Byrom_ATT 1, lines 7-10 for associated customer numbers.

Witness: Jessica R. Byrom
Date: August 18, 2025

EXHIBIT MEC-24

RESERVED

EXHIBIT MEC-25

RESERVED

EXHIBIT MEC-26

RESERVED

Question:

1. Refer to Connolly rebuttal, p. 4. Identify with specific reference to testimony, exhibits, and/or order language the basis for your assertion that the notion that the Company must demonstrate that an LEDR customer will pay all its marginal distribution costs in order to gain approval of a facilities allowance is not consistent with the methodology approved by the Commission in approving the LEDR.

Response:

Please see the Large Economic Development Rate Facilities Allowance discussion starting on page 414 of the Final Order in Case No. U-21585. Specifically, page 424 states:

"Accordingly, the Commission finds persuasive the ALJ's recommendation that Consumers' proposed facilities allowance for Rate LED in this case should be denied; however, in its next electric rate case, if the company believes it beneficial to provide a facilities allowance for Rate LED, Consumers should propose a facilities allowance that includes only distribution and system contribution revenues, not power supply revenues, and that is based on a limited term, similar to DTE Electric's Rate D13."

The Company's proposal in the instant case is to provide a facilities allowance that includes only distribution and system contribution revenues and is based on a limited (5 year) term. This language from the Final Order in Case No. U-21585 makes no reference to proof of marginal distribution cost coverage.

Witness: Laura M. Connolly
Date: October 24, 2025

Question:

2. Refer to Connolly rebuttal, p. 5 lines 5-12:

a. Produce the contracts (full contracts, with redactions as necessary) containing language expressing the Company's intention to file a request to amend the LEDR rate to allow already-signed LEDR customers to qualify for a CIAC credit.

b. Produce any and all documents that support (or are inconsistent with) your contention that customers who signed to take service under LEDR considered the contract language and potential for an allowance as part of their decision to locate in Consumers Energy's service territory.

Response:

a. Please see U-21870-AG-CE-0478_Hayward_Attachment 3a Conf, Part 9 Section (j).
   See also U-21870-AG-CE-0478_Hayward_Attachment 5 Conf, Part 9 Section (j).
b. See response to part (a).

Witness: Laura M. Connolly
Date: October 24, 2025

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-29C

Question:

3. Refer to Connolly rebuttal, p. 5 lines 19-23:

   a. Explain when and how the Company intends to reconcile any differences in actual collections to proposed collections.

   b. Explain when and how the Company would adjust charges after reconciling any such differences.

Response:

a. While the contract does not specify a reconciliation cadence, the Company intends to do a periodic review of actual collections to proposed collections for each Rate LED customer. The Company will recalculate a go forward incremental distribution charge based on actual collections at the time of the review. The new incremental distribution charge will be updated through an amendment to the customer rate contract. At the end of the contract, the Company will do a final reconciliation of actual collections to expected calculations.

b. See response to a.

Witness: Laura M. Connolly
Date: October 29, 2025

Question:

4. Refer to Connolly rebuttal, p. 6 lines 4-10:

a. Describe in detail the methodology used to develop the system contribution charge in Case No. U-21160.

b. Produce any and all documents generated in connection with developing that methodology.

c. Produce the contracts (full contracts, with redactions as necessary) that include language stating that the system contribution charge is set for the term of the contract.

d. Explain how a charge based on embedded costs can be both cost-based and fixed for the term of the LEDR contract.

Response:

a. Please see response U-21870-MNSC-CE-0255, part d, which provided a description and the detailed calculation of the system contribution charge.
b. Please see response U-21870-MNSC-CE-0255.
c. Please see U-21870-AG-CE-0478_Hayward_Attachment 3a Conf, U-21870-AG-CE-0478_Hayward_Attachment 5 Conf, U-21870-AG-CE-0478_Hayward_Attachment 6 Conf, and U-21870-AG-CE-0478_Hayward_Attachment 7 Conf. Part 7 of these contracts all state: During the Term of this Agreement, the Customer shall pay a System Contribution Charge of $0.000284 per kWh for all kWh consumed.
d. The system contribution charge was calculated based on embedded capacity as approved in Case No. U-21160. The terms of the Large Economic Development Rate allowed for certain portions of the rate to be fixed for the term of the contract.

Witness: Laura M. Connolly
Date: October 24, 2025

EXHIBIT MEC-32

RESERVED

EXHIBIT MEC-33

RESERVED

Question:

1. Refer to the Rebuttal Testimony of Laura M. Connolly, pp. 2-3:

a. Please produce the letter agreement with the new data center that you describe, with any necessary redactions to protect customer identity.

b. Produce any internal and/or external communications related to the timing of (1) a rate contract with the new data center; and/or (2) the timing of any capital expenditures related to the new data center; and/or (3) load ramp schedule for the data center.

Response:

a. Please see response to U21870-MNSC-CE-0209.

b. In verbal discussions, the customer has indicated a preference to wait for an order in Case No. U-21859 before discussing rate contract detail. Without a rate contract, the Company cannot finalize load ramp or capital expenditure information.

Witness: Laura M. Connolly
Date: October 30, 2025

CONFIDENTIAL ATTACHMENT NOT INCLUDED

IN PUBLIC VERSION OF EXHIBIT MEC-35C

Question:

2. Refer to Connolly rebuttal, p. 3 lines 20-22:

a. Identify and describe in detail the IRP sensitivity or sensitivities that you believe reasonably reflect the company's expected data center load at relevant time intervals.

b. Please produce any and all documents related to your answer.

Response:

a. Preparations of the Company's next IRP are in progress and determinations of all sensitivities are not yet finalized. I believe it is reasonable to include a sensitivity based on contracted load expected on the system during the IRP forecast period along with a scenario based on load growth that is considered highly probable, based on advanced discussions with potential customers.

b. Detailed documents related to analyses in the IRP will be provided as part of that proceeding.

Witness: Laura M. Connolly
Date: October 30, 2025

EXHIBIT MEC-37

RESERVED

Question:

5. Refer to Exhibit No. A-202 (RTB-24).

   a. Please provide all supporting documents, workpapers, and analyses used in developing this new concept approval, in electronic format with formulas intact where applicable.

   b. Please provide the supporting calculation for all NPVs, in electronic format with formulas intact where applicable.

   c. Please provide the supporting sources for all assumed or calculated costs and benefits of each alternative.

   d. Please provide support for the calculation of annual capacity value, including the application of probabilities, in electronic format with formulas intact where applicable.

   e. Please describe why the probabilities were applied after 2028 and describe how these post-2028 values were used in the calculation.

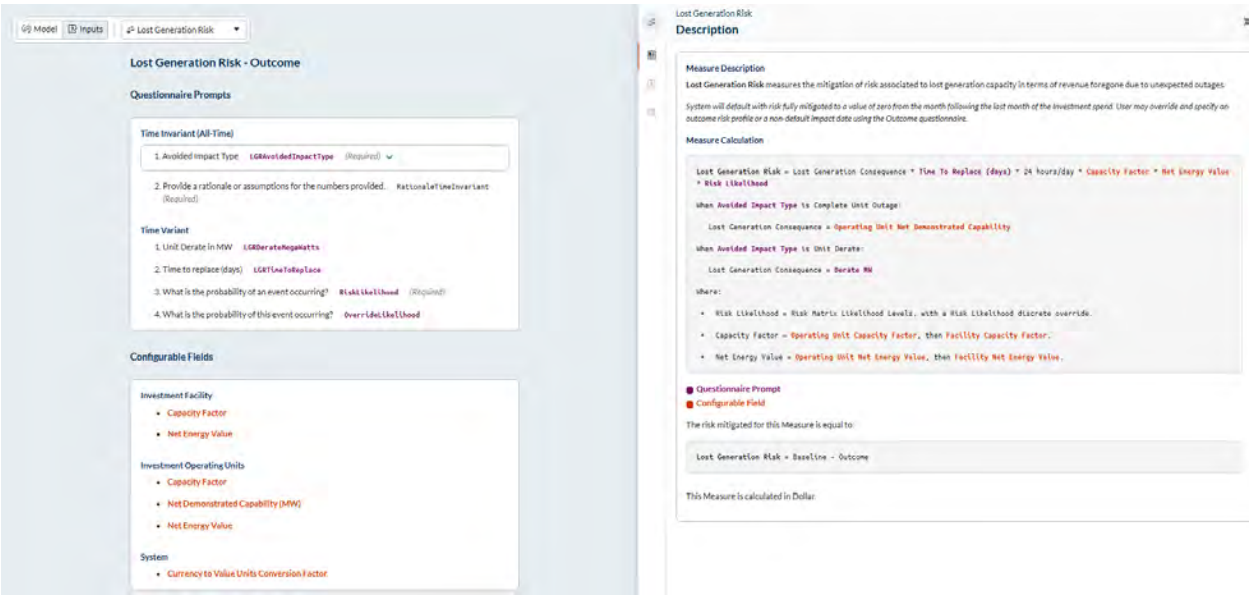
   f. Regarding energy value, confirm that even under a 104 MW derate there would be hours of no energy losses because the plant would not be operating at a high level regardless of the derate.

   g. Confirm that there is potential for the Company to replace the derated capacity for a three-year period at a cost lower than 75% of CONE. If denied, please explain.

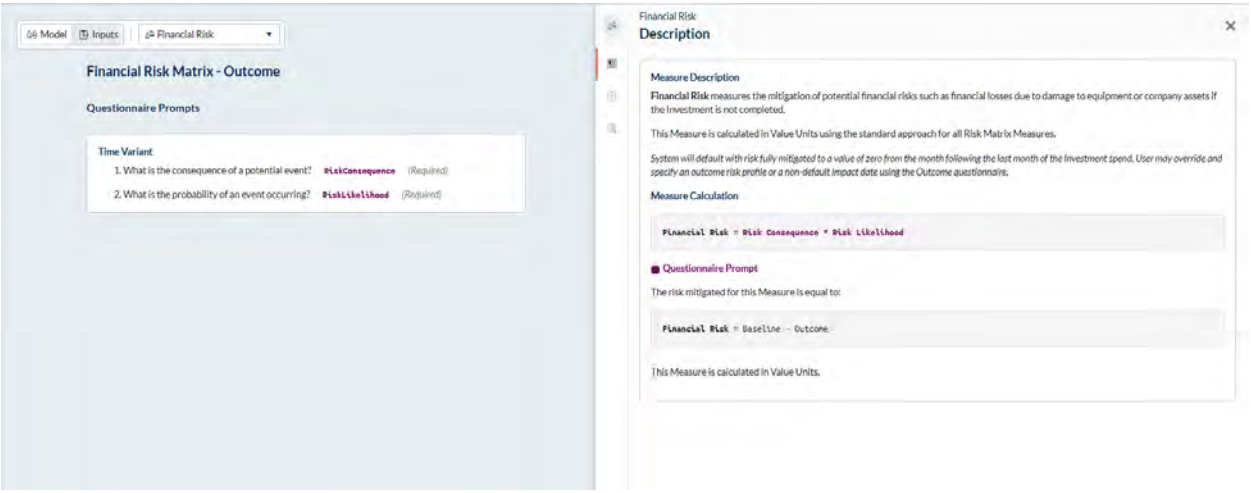
Response:

a. The supporting documentation is reflected in the PSCR case values that are embedded in the Copperleaf models as discussed in prior discovery responses. These values were provided in response to discovery questions U21870-MNSC-CE-071 and U-21870-MNSC-CE-072. The differences between the modeling previously provided and those represented in Exhibit A-202 (RTB-24) are discussed in my rebuttal testimony beginning on page 29. The calculations that the Copperleaf software utilizes are described in the following screen clipping from the software. The assumptions are detailed in the Exhibit. The software provides the results, but it does not have an excel type document that has calculations intact.

Lost Generation Risk



Financial Risk



b. The Company provided examples of the NPV calculations that Copperleaf performs and a document that explains in detail how those are calculated (see Exhibit A-205 (RTB-27)) and example in U21870-MNSC-CE-0224_ATT_0003. See my rebuttal testimony beginning on page 33.

c. See the response to subparts b and d.

d. For annual capacity value and application of probability, the Company provided the generic calculator used for estimating potential capacity lost revenue as well as a document explaining in detail how it works (see Exhibit A-205 (RTB-27)). The probability portion of this question is related to the financial risk model in Copperleaf as captured in subpart a. For the assumed values for Capacity Factor by month see U21870-MNSC-CE-0768_ATT_0001. This document includes all the data for the

background calculations for the Jackson site. In row 2 the assumed capacity factors are listed by month starting January 2024 in column O progressing by month moving to the right. These values are the same as the latest approved PSCR case.

e. Copperleaf's valuation methodology begins by establishing a baseline risk scenario—representing the cumulative risk of inaction through 2039. This baseline serves as the foundation for comparison. To determine the value of a proposed project, Copperleaf subtracts both the risk that would be mitigated prior to the project's completion and the associated project costs from the total baseline risk. The result is the net value of the project, expressed as the amount of risk mitigated. Value = Baseline Risk – (Residual Risk + Project Cost)

f. Confirmed. However, the updated calculations include capacity factor projections and therefore are reflected in the new results.

g. The 75% of CONE value is simply a planning assumption and is not a value based on specific market intelligence. I am unable to confirm the availability of capacity, nor the cost of any such capacity.

Witness: RICHARD T. BLUMENSTOCK
Date: October 29, 2025

Question:

6. Refer to Exhibit No. A-203 (RTB-25).

   a. Please provide all supporting documents, workpapers, and analyses used in developing this new concept approval, in electronic format with formulas intact where applicable.

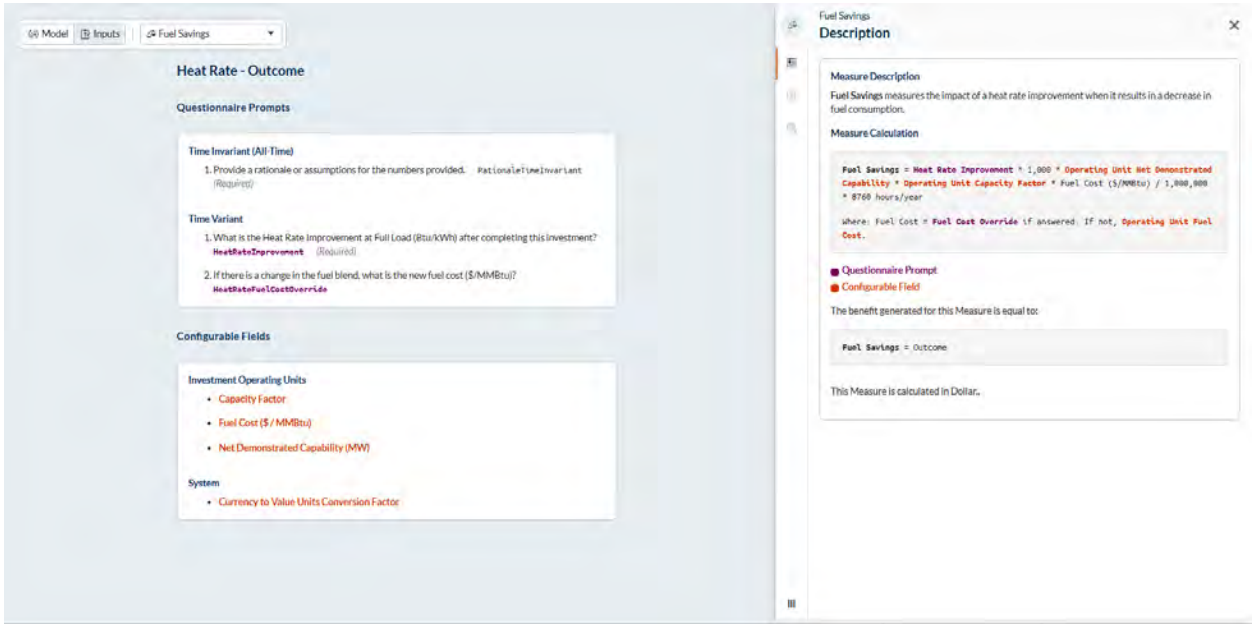
   b. Please provide the supporting calculation for all NPVs, in electronic format with formulas intact where applicable.

   c. Please provide the supporting sources for all assumed or calculated costs and benefits of each alternative, in electronic format with formulas intact where applicable.

Response:

a. For the LM VIGV project benefits (heat rate during duct burning (286 Btu/kWh) and non-duct burning (189 Btu/kWh)), GE provided us with a fact sheet on the VIGV enhancement as well as performance estimate graphs. This simple cycle info was entered into our EBSILON® Professional modeling software program to get the estimated heat rate changes for the JGS combined cycle plant. Attached as U21870-MNSC-CE-0769_ATT_0001, U21870-MNSC-CE-0769_ATT_0002_CONF, and U21870-MNSC-CE-0769_ATT_0003_CONF are copies of the VIGV fact sheet and budgetary estimates/ proposals which have info utilized for modeling, and communication of EBSILON® modeling results. The calculation for Heat Rate that the Copperleaf software utilizes are described in the following screen clipping from the software. The calculations for Lost Generation Risk and Financial Risk are included in U21870-MNSC-CE-0768 part a. The assumptions for each calculation are detailed in the Exhibit. The software provides the results, but it does not have an excel type document that has calculations intact. The Fuel Cost assumptions are included in U21870-MNSC-CE-0768_ATT_0001, row 3.

Heat Rate



b. The concept approval and the NPV calculations are performed in Copperleaf pursuant to the procedure provided in both discovery and as Exhibit A-203 (RTB-25). No other NPV support is available in electronic format other than the detailed discussion of how Copperleaf models NPV as provided in Exhibit A-205 (RTB-27).

c. Please see attachments U21870-MNSC-CE-0769_ATT_0004_CONF, U21870-MNSC-CE-0769_ATT_0005_CONF, and U21870-MNSC-CE-0769_ATT_0006_CONF, which reflect the costs for the stalled engine. This represents the bulk of the total cost.

Witness: RICHARD T. BLUMENSTOCK
Date: October 27, 2025

Question:

5. Refer to the rebuttal testimony of Quentin A. Guinn, Q&A11, on pages 5-6. The witness states that "the Company is uncertain whether Mr. Jester's recommendation [to fulfill all light-duty vehicle replacements with electric vehicles no later than 2030] can be achieved based on the Vehicle Capital Replacement Plan's historical spending amounts."

a. Please describe in detail the basis for the witness's statement that "the Company is uncertain" whether this recommendation can be achieved. Identify and describe all analyses, data, or other information the witness relied upon in forming this view. If no such analyses or data exist, please confirm that this statement reflects only the witness's speculation or judgment rather than a documented analysis.

b. Please state whether the Company is willing to provide, no later than its next rate case filing, an assessment of whether fulfilling all light-duty vehicle replacements with electric vehicles by 2030 would require departing from the Company's Vehicle Capital Replacement Plan's historical spending levels. If no, please explain why the Company is not willing to provide such an assessment.

Response:

a. The Company maintains approximately 900 internal combustion engine (ICE) light duty vehicles in its fleet. A Chevrolet Silverado EV built to the Company's specifications costs approximately $85,000. Using this cost as the per unit average cost to replace a light duty ICE vehicle with an electric counterpart, the Company would incur approximately $76.5 million in expense to electrify all 900 ICE light duty vehicles in its fleet. If this replacement plan is executed over a 3-year period (e.g. calendar years 2027, 2028, and 2029), the Company would incur approximately $25.5 million in annual expense. The projected test year in this rate case for the Fleet Vehicle Capital Replacement Plan totals $20.8 million and represents all vehicles planned for replacement during the test year including those planned for replacement with an electric vehicle.

b. Yes. In its next rate case filing, the Company is willing to provide an assessment of whether fulfilling all light duty vehicle replacement with electric vehicles by 2030 would require departing from the Company's Vehicle Capital Replacement Plan's historical spending levels.

Witness: Quentin A. Guinn
Date: October 28, 2025

EXHIBIT MEC-41

RESERVED

Question:

2. Refer to the rebuttal testimony of witness Daly, page 8, and the direct testimony of witness Stewart, page 43, figure 20.

a. For calendar years 2019-2023, please provide the total number of miles trimmed on LVD and HVD circuits.

b. For calendar years 2019-2023, please provide the total number of miles trimmed on LVD circuits, itemized by circuit voltage.

c. For calendar years 2019-2023, please provide the total amount Consumers spent on forestry.

d. For calendar years 2019-2023, please provide Consumers' spending on forestry, itemized by labor, material, contractor, non-labor overhead, and non-labor other costs (See Stewart Direct, Ex A-175, p 1).

Response:

a. The total number of LVD and HVD O&M miles cleared in calendar years 2019-2023 are shown in Figure 1 below. These numbers exclude spray miles.

Figure 1: LVD and HVD O&M Miles Cleared in 2019-2023

Year	LVD Miles Cleared	HVD Miles Cleared
2019	3,115	1,102
2020	3,973	1,116
2021	4,884	1,178
2022	5,900	1,106
2023	5,922	1,153

b. The total number of LVD O&M miles cleared in calendar years 2019-2023 by circuit voltage at the substation are shown in Figure 2 below. These numbers exclude spray miles.

Figure 2: LVD O&M Miles Cleared in 2019-2023 by Circuit Voltage at Substation

Year	4.8 Delta	4.8 Wye	7.2 Delta	7.2 Wye	11.0 Delta	12.0 Delta	13.2 Delta	14.4 Delta	14.4 Wye	Demand Clearing	LVD Miles Cleared
2019	0	1,125	0	383	38	59	22	166	1,288	34	3,115
2020	36	1,512	0	665	24	4	108	44	1,553	27	3,973
2021	1	1,804	0	760	119	28	70	65	1,961	76	4,884
2022	60	2,100	0	1,057	71	27	58	116	2,356	55	5,900
2023	19	2,386	1	1,153	183	0	62	115	1,954	49	5,922

c. The total amount of Forestry O&M expense for calendar years 2019-2023 is shown in Figure 3 below.

Figure 3: Annual Total Forestry O&M Expense 2019-2023

Year	Total Forestry O&M Expense
2019	$53,289,931
2020	$55,274,437
2021	$86,567,155
2022	$102,003,474
2023	$109,093,473

d. The Forestry O&M expense for calendar years 2019-2023 itemized by labor, material, contractor, non-labor overhead, and non-labor other is shown in Figure 4 below.

Figure 4: Annual Itemized Forestry O&M Expense 2019-2023

Year	Labor	Material	Contractor	Non-Labor Overhead	Non-Labor Other	Total Forestry O&M Expense
2019	$3,333,574	$0	$48,911,991	$1,044,366	$0	$53,289,931
2020	$3,181,745	$0	$50,977,083	$1,115,609	$0	$55,274,437
2021	$4,745,873	$0	$81,019,448	$801,833	$0	$86,567,155
2022	$3,774,301	$0	$97,229,175	$999,997	$0	$102,003,474
2023	$3,393,439	$0	$104,881,195	$818,840	$0	$109,093,473

Witness: Sara E. Stewart
Date: October 29, 2025

Question:

3. Refer to the rebuttal testimony of witness Stewart, page 6, lines 12-20. Please provide all benchmarking studies assessing the line clearing cycles used by other utilities.

Response:

In assessing line clearing cycles of other utilities, the Company utilized the benchmarking provided by the Liberty Consulting Group (Liberty) in the distribution audit in Case No. U-21305. The Company also utilized informal benchmarking discussions with other utilities not included in Liberty's provided benchmarking.

Witness: Sara E. Stewart
Date: October 29, 2025

Question:

4. Refer to the rebuttal testimony of witness Daly, page 9, where the witness discusses the LVD Pole Replacement Surge Proposal.

a. Please provide the Company's total LVD pole replacements for each year from 2019-2024.

b. Please provide the Company's total spending on LVD pole replacements for each year from 2019–2024.

c. Please provide the total number of LVD pole replacements made as part of the LVD Lines Reliability Program for each year from 2019-2024.

d. Please provide the annual average cost per LVD pole replacement for each year from 2019-2024.

Response:

a. See Attachment 1 to this response.

b. See Attachment 1 to this response. Please note that the dollar amounts provided for the subpart are not only the dollars spent on replacing poles; they are the dollars spent on all projects that involved replacing poles, even if other work was done as well. The Company is not able to segregate out only the dollars spent on pole replacements for all projects.

c. See Attachment 1 to this response.

d. As stated in subpart b, costs for all Company pole replacements include all work associated with any orders that include any pole replacements. The Company is not able to calculate a Company-wide comprehensive pole replacement unit cost. The unit cost for each pole 2019 – 2024, in the LVD Lines Reliability Pole Replacement investment category only is included in Attachment 1. As indicated in the response to U21870-AG-CE-0347, costs decreased in 2024 because the Company implemented new contracts with suppliers following a bidding process, and the new contracts included lower pole costs.

Witness: Jennifer M Partlan
Date: October 30, 2025

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		U21870-MNSC-CE-0867												
2		Attachment 1												
3														
4														
5														
6			**Year**											
7		**Investment Category**	**2019**		**2020**		**2021**		**2022**		**2023**		**2024**	
8			**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**	**Cost**	**Units**
9	a, b	Pole Replacements, Company-wide	$165,438,354.95	9,991	$217,669,811.17	14,663	$207,118,728.33	12,967	$210,766,205.61	13,316	$193,492,332.84	13,686	$200,175,363.87	11,188
10	c	Pole Replacements, LVD Lines Reliability Only	$13,209,681.00	1,573	$8,239,856.00	1,861	$10,599,623.00	1,055	$2,534,948.00	172	$1,894,863.00	137	$1,330,180.00	231
11	d	Unit Cost, Reliability Only		$8,397.76		$4,427.65		$10,047.04		$14,738.07		$13,831.12		$5,758.35

Question:

5. Refer to the rebuttal testimony of witness Bleckman, page 3, where the witness states:

"[T]he Company cannot finance the regulatory asset with debt. Doing so would add additional strain to the Company's credit metrics…" Did Consumers calculate its expected company-wide FFO-to-Debt ratio if the Commission adopts witness Coppola's or witness Bunch's recommendation? If so, provide the calculations and associated workpapers and identify all assumptions used in the analysis. If not, explain why not.

Response:

The Company did not calculate a pro forma FFO-to-Debt ratio assuming witness Coppola's or witness Bunch's recommendation. A pro forma calculation is not required to demonstrate that a higher level of debt reduces the Company's FFO-to-Debt ratio. As explained in direct and rebuttal testimony, the short-term debt rate is not an acceptable financing assumption for the deferred ramp up regulatory asset as financing the asset balance solely with debt would add additional strain to the Company's credit metrics. The Company intends to fund the ramp up with a mix of long-term debt and equity, aligned with the Company's approved capital structure. Therefore, the Company's total WACC matches the ramp up related spending and is the appropriate rate to be applied to the regulatory asset.

Witness: MARC R. BLECKMAN
Date: October 29, 2025

Question:

3. Refer to Myers Rebuttal, p 16. Responding to NRDC-CUB witness Bunch, Ms. Myers states, "While the Company strives to improve its efficiency and productivity in order to control costs, it is important to note that the Company has unique regulatory obligations, most importantly the obligation to serve that may cause it to respond to cost pressures differently than unregulated companies." Please elaborate on the specific regulatory obligations Ms. Myers is referring to and how they differ from the cost drivers identified by witness Bunch, namely, "sales growth or specific performance or legal requirements."
(Bunch Direct, p 31)

Response:

The referenced portion of my testimony mentioning unique regulatory obligations was primarily referring to the Company's obligation to provide service to customers. Although there are many specific regulatory and legal requirements that apply to the Company, including Michigan laws that apply to regulated utilities and MPSC rules and requirements. It was unclear from Mr. Bunch's testimony that his use of the language sales growth or specific performance or legal requirements was intended to cover the Company's unique regulatory obligations, including its obligation to serve, since Mr. Bunch only excluded Line Clearing costs from his proposed adjustment. The full paragraph from page 31 of Mr. Bunch's testimony that includes the term "sales growth or specific performance or legal requirements" states, "For O&M costs, I recommend the Commission apply this methodology to all proposed O&M expenses and disallow excess costs unless they are driven by sales growth or specific performance or legal requirements, such as the costs associated with the Company's Line Clearing surge. Applying a PAI factor to all O&M costs is consistent and comparable with the development of baseline cost projections developed by escalating historical actuals using inflation."

Witness: Heidi J. Myers
Date: October 29, 2025

Question:

4. Refer to the rebuttal testimony of Jeffrey A. Myrom, Q&A12, on pages 7, lines 2-4. Mr. Myrom states that "[i]f the fast-charging proposal proves insufficient to achieve the skeleton network outcome, then the Company is very willing to consider higher rebate values and a longer application window duration in a future filing."

a. Please describe in detail what the Company means by "skeleton network outcome." Has the Company defined or otherwise documented what constitutes the "skeleton network"? If so, please identify and produce any such documentation or analysis.

b. Please explain how the Company intends to assess whether the "skeleton network outcome" has been achieved, including: the specific metrics, criteria, or thresholds the Company will use to determine sufficiency of the fast-charging proposal; and the timing and process by which the Company will make that assessment.

c. Please state whether the Company intends to include in its next rate case or Transportation Electrification Plan filing any proposal to evaluate progress toward, or completion of, the "skeleton network outcome." If yes, please describe the nature of that proposal. If no, please explain why not.

Response:

a. The Company has utilized the National Electric Vehicle Infrastructure (NEVI) standards, 23 CFR Part 680, as a benchmark for a skeleton network. Hence the proposal to rebate up to four 150 kW direct current fast chargers (DCFCs) in a community.

b. The Company will continue to collaborate with Staff and other stakeholders in future cases to determine when a skeleton network has been achieved that will allow the charging network to expand independent of Company rebates. Assuming that the temporary DCFC rebate proposal is approved by the MPSC, the earliest that DCFC projects could be selected for a rebate is likely Q4 of 2026, with actual rebate awards paid upon completion in 2027. Thus, the Company would likely begin reviewing which communities have four or more 150 kW DCFCs across two or more different sites in Q4 2026. The Company utilizes PlugShare, in addition to a variety of charge point operator apps, to screen for the location, number and kW output rating of DCFCs. After that screening, the Company would then review the DCFC rebate applications received against the criteria proposed (e.g., amenities, payment, lighting, etc.) in testimony. Rebate selections would be made monthly for two years after launch of the rebate application.

c. If the temporary DCFC rebate proposal is approved by the MPSC, then the 2027 annual Transportation Electrification Plan (TEP) report is likely to be the first analysis of DCFC network progress. The Company cannot predict what the analysis will reveal, so it is premature to commit to any proposals that might stem from this analysis.

Witness: Jeffrey A. Myrom
Date: October 31, 2025

MPSC CASE NO. U-21870

First Discovery Requests of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan to Solar Technology LLC

21870-MNSC-SLT-1:

Refer to the Rebuttal Testimony of Michael P. Gorman, p. 7 lines 7-8: Identify all Commission-approved contracts for LEDR customers that you refer to, including the date of approval and the case number in which they were approved.

Objection:

Respondent objects to this request to the extent that it seeks information that is in the possession of, known to, or otherwise equally available to the proponent. Respondent further objects to this request because it seeks information from other parties that is not in the possession, custody or control of respondent. Respondent further objects to this request to the extent that it imposes requirements on the respondent in excess of what is required under the Michigan Court Rules. Subject to this objection, see the response below.

Response:

The point of my referenced testimony is that the Commission should honor and not attempt to change contracts between parties, including facilities agreements and Rate LED contracts. I believe this to be true whether the contracts have been approved by the Commission or not, but particularly in the case where contracts have been approved by the Commission.

Objection By: Counsel

Response By: Michael P. Gorman

Date: November 4, 2025

MPSC CASE NO. U-21870

First Discovery Requests of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan to Solar Technology LLC

21870-MNSC-SLT-2:

Has Solar Technology signed a contract with Consumers? If yes, please produce it. If more than one, please produce them all.

Objection:

Respondent objects to this request to the extent that it seeks information that is not relevant and that contains confidential, commercially sensitive and personally identifiable customer account information. Subject to this objection, see the response below.

Response:

Yes. See Consumers' response to discovery request U21870-AG-CE-0478.

Objection By: Counsel

Response By: Michael P. Gorman

Date: November 4, 2025

MPSC CASE NO. U-21870

First Discovery Requests of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan to Solar Technology LLC

21870-MNSC-SLT-3:

Refer to Gorman rebuttal, p. 8 lines 19-22:

a. Does every other primary customer have the opportunity to pay the MISO Cost of New Entry for Local Resource Zone 7 as of the date they execute their contract as their production charge? If your answer is yes, please explain in detail.

b. Does every other primary customer have the opportunity to pay either the MISO Real-Time or Day Ahead Locational Marginal Price or charge matching the crediting methodology of energy under the Voluntary Large Customer Renewable Program as their energy charge? If your answer is yes, please explain in detail.

Response:

a. No.

b. No.

Response By: Michael P. Gorman

Date: November 4, 2025

October 30, 2025
MPSC Staff's Answer to Michigan Environmental Council et al's
1st Discovery Request
MPSC Case No. U-21870

Question:

1. Refer to the rebuttal testimony of Mr. Freeman, Q&A6, on pages 2, lines 3-8. Please state whether the witness would support, or would agree not to oppose, extending the availability of Direct Current Fast Charging ("DCFC") rebates through 2030, which is the end of the timeframe covered by the Company's Transportation Electrification Plan ("TEP"). If the witness opposes such an extension, please explain in detail the basis for that position.

Answer:

Staff does not support, but would not actively oppose, the rebates being extended through 2030.

October 30, 2025
MPSC Staff's Answer to Michigan Environmental Council et al's
1st Discovery Request
MPSC Case No. U-21870

2. Refer to the rebuttal testimony of Mr. Freeman, Q&A6, on pages 2, lines 3-8. If the witness does not support extending DCFC rebate availability through 2030, please explain in detail why that position does not conflict with the position taken by the witness in Case No. U-21860, where the witness supported making DTE Energy's EV charging rebates available through the overall TEP timeframe (See Rebuttal Testimony of Staff witness Allan D. Freeman, 5 TR 5206).

Answer:

N/A as per in the answer above.

yellow = Ken

Production Capital Projects Greater than $1 million

Line No.	Plant	Unit	Project Name/Description	Capital Expenditures in Last Rate Case ($) U-21585					Capital Expenditures in Instant Rate Case ($) U-21870				Project Totals Details		
				Historic Test Period	Projected Bridge Period ($)	Projected Test Period ($)	Total Requested for Project ($)	Amount Approved in Commission Order ($)	Historic Test Period	Projected Bridge Period ($)	Projected Test Period ($)	Total Requested for Project ($)	Actual Amount Spent to Date since Project Inception	Total Projected Expenditures for Project ($)	Was this Project Pre-approved in another case? (IRP, Renewable Plan, etc.) If yes, provide Case Number and amount preapproved.
1	Covert	Covert	(12817) COVERT - Long Term Service Agreement - Running capital contract	$ 9,182,029	$ 20,400,000	$ 14,700,000	$ 44,282,029	$ 48,428,021	$ 15,623,033	$ 26,246,048	$ 18,811,878	$ 60,680,959	$ 24,805,062	$ 80,157,926	No
2	Covert	Covert	(13583) CGS - Netmation (MHPSA Operating System & 4S)- Unit 1-3	$ -	$ 709,167	$ 3,337,500	$ 4,046,667	$ 8,361,317	$ 6,046,654	$ 2,921,689	$ 8,843,713	$ 17,812,056	$ 6,046,654	$ 15,812,069	No
3	Covert	Covert	(13570) Covert - Unit 2 - Non LTSA Capital - Extras not included in contract	$ 86,688	$ 750,000	$ 12,609,633	$ 13,446,321	$ -	$ 1,339,561	$ 12,153,320	$ 190,001	$ 13,682,882	$ 1,426,249	$ 25,702,954	No
4	Covert	Covert	PP-00584: CGS HRSG Expansion Joint Replacements	$ -	$ -	$ -	$ -	$ -	$ 1,284,244	$ -	$ -	$ 1,284,244	$ 1,284,244	$ -	No
5	Covert	Covert	(13618) CGS - LCI Replacements (SFC)	$ -	$ 201,667	$ 408,333	$ 610,000	$ 610,000	$ -	$ 1,305,000	$ 2,610,000	$ 3,915,000	$ -	$ 4,525,000	No
6	Covert	Covert	(12818) Covert -Unit 1 Non LTSA Capital - Extras not included in contract	$ -	$ 248,333	$ 1,437,717	$ 1,686,050	$ -	$ -	$ -	$ 9,524,986	$ 9,524,986	$ -	$ 11,211,036	No
7	Covert	Covert	(13571) Covert - Unit 3 - Non LTSA Capital - Extras not included in contract	$ -	$ 750,000	$ 10,609,633	$ 11,359,633	$ -	$ -	$ 9,009,801	$ 4,093,234	$ 13,103,035	$ -	$ 24,462,668	No
8	Covert	Covert	PP-00565: CGS BASE OUTAGE - 2024	$ 788,725	$ 443,333	$ 383,333	$ 1,615,391	$ 1,615,391	$ 198,382	$ 774,000	$ 360,000	$ 1,332,382	$ 987,107	$ 1,960,666	No
9	Covert	Covert	PP-00596: CGS 1 GTG and STG Auto Voltage Regulator	$ -	$ -	$ -	$ -	$ -	$ -	$ 750,000	$ 600,000	$ 1,350,000	$ -	$ 1,350,000	No
10	Covert	Covert	PP-00597: CGS 3 GTG and STG Auto Voltage Regulator	$ -	$ -	$ -	$ -	$ -	$ -	$ 750,000	$ 600,000	$ 1,350,000	$ -	$ 1,350,000	No
11	Covert	Covert	(13446) CGS - 1-3 Emerson DCS Evergreen	$ -	$ 1,041,250	$ 2,448,750	$ 3,490,000	$ 2,676,700	$ 530,441	$ 2,156,101	$ 967,800	$ 3,654,342	$ 530,441	$ 6,613,901	No
12	Covert	Covert	(13573) CGS - Purchase of site spare GSU	$ 1,722,987	$ 1,000,000	$ 4,500,000	$ 7,222,987	$ 2,446,442	$ (33,729)	$ 1,500,000	$ 5,910,000	$ 7,376,271	$ 1,689,258	$ 12,910,000	No
13	Covert	Covert	(13604) CGS - Cooling Tower Gearboxes	$ 79,877	$ 1,161,732	$ 1,039,192	$ 2,280,801	$ 1,701,609	$ 453,104	$ 675,000	$ 675,000	$ 1,803,104	$ 532,981	$ 3,550,924	No
14	Covert	Covert	Covert Security and Network	$ 2,208,169	$ -	$ -	$ 2,208,169	$ 2,208,169	$ 38,785	$ 685,712	$ 700,712	$ 1,425,209	$ 2,246,954	$ 1,386,424	No
15	Covert	Covert	PP-00560: CGS SMALL SITE CAPITAL-2024	$ 180,071	$ 175,000	$ 150,000	$ 505,071	$ 505,071	$ 648,890	$ 380,000	$ 285,000	$ 1,313,890	$ 828,961	$ 990,000	No
16	Jackson	Jackson Site Commons	PP-00554: JGS - 1-6 Feedwater Desuperheater Valve	$ -	$ 831,433	$ 16,667	$ 848,100	$ 848,100	$ 1,871,081	$ 18,000	$ -	$ 1,889,081	$ 1,871,081	$ 866,100	No
17	Jackson	Jackson Site Commons	(6006) Jackson GE Long Term Service Agreement FFH	$ 8,907,616	$ 12,337,500	$ 11,116,875	$ 32,361,991	$ 24,312,827	$ 8,615,181	$ 16,200,153	$ 12,810,121	$ 37,625,455	$ 17,522,797	$ 52,464,649	No
18	Jackson	Jackson Site Commons	(5921) Jackson GE LTSA Historical Extra Work Expected	$ 496,531	$ 2,908,333	$ 350,000	$ 3,754,864	$ 2,212,645	$ 330,371	$ 2,115,001	$ 315,000	$ 2,760,372	$ 826,902	$ 5,688,334	No
19	Jackson	Jackson Site Commons	PP-00568: JGS 2024 Base Outage	$ 983,951	$ 350,000	$ 300,000	$ 1,633,951	$ 1,633,951	$ 744,444	$ 270,000	$ 270,000	$ 1,284,444	$ 1,728,395	$ 1,190,000	No
20	Jackson	Jackson Site Commons	(13478) JGS - Generator Step Up Transformer (GSU) Site Spare	$ -	$ 83,333	$ 833,333	$ 916,667	$ 916,667	$ -	$ 1,333,333	$ 2,333,334	$ 3,666,667	$ -	$ 4,583,334	No
21	Jackson	Jackson Site Commons	JGS - LM6000 ESN 191-306 HP Turbine S2 Nozzle replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,336,072	$ -	$ 1,336,072	$ -	$ 1,336,072	No
22	Jackson	Jackson Site Commons	JGS - Engine 191-306 Overhaul	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,000	$ 6,130,000	$ 6,210,000	$ -	$ 6,210,000	No
23	Jackson	Jackson Site Commons	JGS - Unit 7 Gas turbine rotor replacement	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,000	$ 1,663,577	$ 1,743,577	$ -	$ 1,743,577	No
24	Jackson	Jackson Site Commons	(13475) JGS - LM1-6 VIGV(variable inlet guide vane) Project	$ -	$ 136,667	$ 900,000	$ 1,036,667	$ 1,036,667	$ 7,885	$ 646,911	$ 960,102	$ 1,614,898	$ 7,885	$ 2,643,680	No
25	Jackson	Jackson Site Commons	PP-00551: JGS Small Site Capital	$ 326,744	$ 200,000	$ -	$ 526,744	$ 526,744	$ 645,835	$ 380,000	$ 285,000	$ 1,310,835	$ 972,579	$ 865,000	No
26	Zeeland	Zeeland	(13499) ZGS - 2C GSU Rewind	$ 13,884,854	$ 5,546,538	$ -	$ 19,431,392	$ 22,375,273	$ 9,696,239	$ 2,430,000	$ -	$ 12,126,239	$ 23,581,093	$ 7,976,538	No
27	Zeeland	Zeeland	(12833) ZGS - Site Spare GSU	$ 758,314	$ 589,607	$ 6,449,004	$ 7,796,925	$ 7,796,925	$ 2,039,715	$ 2,340,637	$ 4,481,207	$ 8,861,559	$ 2,798,029	$ 13,860,455	No
28	Zeeland	Zeeland	PP-00478: ZGS-P2 599 699 345kV Breaker Replcmnt	$ 598,109	$ 319,559	$ -	$ 917,668	$ 917,668	$ 1,855,883	$ -	$ -	$ 1,855,883	$ 2,453,992	$ 319,559	No
29	Zeeland	Zeeland	(6593) Zeeland Long Term Service Agreement - Running Capital Contract	$ 6,656,511	$ 9,520,000	$ 8,181,333	$ 24,357,844	$ 34,479,075	$ 21,698,502	$ 43,697,329	$ 8,331,428	$ 73,727,259	$ 28,355,013	$ 69,730,090	No
30	Zeeland	Zeeland	(9694) ZGS - HRSG Casing Replacement	$ 699,976	$ 2,097,620	$ -	$ 2,797,596	$ 3,438,683	$ 2,839,528	$ 45,000	$ -	$ 2,884,528	$ 3,539,504	$ 2,142,620	No
31	Zeeland	Zeeland	(9943) ZGS - LTSA - Extras not included in contract (cranes, mobile equipment)	$ 15,184,014	$ 3,925,000	$ 4,275,000	$ 23,384,014	$ 20,336,980	$ -	$ 4,703,401	$ 810,000	$ 5,513,401	$ 15,184,014	$ 13,713,401	No
32	Zeeland	Zeeland	(6596) ZGS Base Outage Capital	$ 547,912	$ 482,555	$ 424,444	$ 1,454,911	$ 1,454,911	$ 837,882	$ 381,900	$ 382,500	$ 1,602,282	$ 1,385,794	$ 1,671,399	No
33	Zeeland	Zeeland	(11712) ZGS - Phase II Turbine Replacements	$ -	$ -	$ 1,884,167	$ 1,884,167	$ 1,695,750	$ -	$ 10,174,501	$ 10,174,501	$ 20,349,002	$ -	$ 22,233,169	No
34	Zeeland	Zeeland	(13497) ZGS - Phase 2 Gas Turbine Advanced gas path replacement and axial fuel staging	$ -	$ 10,000	$ 50,000	$ 60,000	$ 60,000	$ -	$ 54,000	$ 13,923,002	$ 13,977,002	$ -	$ 14,037,002	No
35	Zeeland	Zeeland	PP-00562: ZGS - ABB DCS Evergreen	$ -	$ 200,000	$ -	$ 200,000	$ 200,000	$ 723,858	$ 648,680	$ -	$ 1,372,538	$ 723,858	$ 848,680	No
36	Karn	Karn 3	(9359) Karn 3 DCS Evergreen	$ 317,080	$ 1,507,000	$ -	$ 1,824,080	$ 1,611,845	$ 1,190,970	$ -	$ -	$ 1,190,970	$ 1,508,050	$ 1,507,000	No
37	Karn	Karn 3	(9360) Karn 3 Cooling Tower Internal Structure Replacement	$ 5,439,366	$ 6,000,000	$ -	$ 11,439,366	$ 8,879,212	$ 4,182,958	$ -	$ -	$ 4,182,958	$ 9,622,324	$ 6,000,000	No
38	Karn	Karn 3	B-PT-00099: Karn 3 Combustion Air Heater (CAH) replacement	$ -	$ 2,200,000		$ 2,200,000	$ 2,464,286	$ 1,470,196	$ 2,700,000	$ 1,800,001	$ 5,970,197	$ 1,470,196	$ 6,700,001	No
39	Karn	Karn 3	PT-02886: KARN 3&4 TANK FARM HEATING LINE REPLACE	$ 155,314	$ 30,000	$ -	$ 185,314	$ 185,314	$ 1,216,552	$ -	$ -	$ 1,216,552	$ 1,371,866	$ 30,000	No
40	Karn	Karn 4	PT-02952: KARN 4 COMBUSTION AIR HEATER REPLACEMENT	$ -	$ -	$ -	$ -	$ -	$ 453,628	$ 3,000,000	$ 2,250,000	$ 5,703,628	$ 453,628	$ 5,250,000	No
41	Karn	Karn 4	B-PT-00093: K4 ID Fan Inlet Damper Replacements	$ (562)	$ -	$ -	$ (562)	$ (562)	$ -	$ 2,700,000	$ -	$ 2,700,000	$ (562)	$ 2,700,000	No
42	Karn	Karn 3&4	(6289) Karn 3&4 Sync Wire Replacement	$ 136,715	$ 1,260,000	$ 20,000	$ 1,416,715	$ 1,614,236	$ 1,260,407	$ 261,000	$ -	$ 1,521,407	$ 1,397,122	$ 1,541,000	No
43	Karn	Karn 3&4	(13480) Karn 3&4 - Plant heating boilers	$ 4,836,052	$ 1,730,000	$ -	$ 6,566,052	$ 7,890,596	$ 4,466,759	$ 90,000	$ -	$ 4,556,759	$ 9,302,811	$ 1,820,000	No
44	Karn	Karn 3&4	(6240) Karn 3&4 Ductwork Expansion Joint Replacement - ID Fans to Stack	$ (11,895)	$ 710,667	$ 1,900,000	$ 2,598,772	$ 2,408,772	$ (234,494)	$ 1,800,000	$ 1,800,000	$ 3,365,506	$ (246,389)	$ 6,210,667	No
45	Karn	Karn 3&4	New Electrical System from Weadock Sub for Karn 3 and 4	$ -	$ -	$ -	$ -	$ -	$ 1,523,648	$ -	$ -	$ 1,523,648	$ 1,523,648	$ -	No
46	Karn	Karn 3&4	Discharge Line Reroute for K 3 and 4 Sump Water	$ -	$ -	$ -	$ -	$ -	$ 1,905,159	$ -	$ -	$ 1,905,159	$ 1,905,159	$ -	No
47	Karn	Karn 3&4	New building to house new fire water system	$ -	$ -	$ -	$ -	$ -	$ 1,019,275	$ -	$ -	$ 1,019,275	$ 1,019,275	$ -	No
48	Karn	Karn 3&4	New 46kV to 4160 transformer to repower facilities	$ -	$ -	$ -	$ -	$ -	$ 3,065,403	$ -	$ -	$ 3,065,403	$ 3,065,403	$ -	No
49	Karn	Karn 3&4	PT-02940: Karn 3&4 -Small Site Capital-2024	$ -	$ 933,333	$ 500,000	$ 1,433,333	$ 1,433,333	$ 735,316	$ 380,000	$ 285,000	$ 1,400,316	$ 735,316	$ 2,098,333	No
50	Ludington	Ludington Site Commons	(6390) LPS Intake Gate and Gate House Mechanical Replacement	$ 172,824	$ 409,099	$ 1,666,014	$ 2,247,937	$ 2,081,336	$ 59,491	$ 425,376	$ 937,863	$ 1,422,730	$ 232,315	$ 3,438,352	No
51	Ludington	Ludington Site Commons	(6391) LPS 480 Volt Motor Control Centers for DLC	$ 863,141	$ 993,800	$ 1,566,400	$ 3,423,341	$ 3,266,701	$ 411,310	$ 1,287,697	$ 1,352,043	$ 3,051,050	$ 1,274,451	$ 5,199,940	No
52	Ludington	Ludington Site Commons	PH-20093: LPS Replace Lower Penstock Expansion	$ 3,327,559	$ 2,716,000	$ -	$ 6,043,559	$ 5,758,816	$ 323,359	$ 2,009,804	$ -	$ 2,333,163	$ 3,650,918	$ 4,725,804	No
53	Ludington	Ludington Site Commons	(12723) Ludington LPS Oil Water Separator Replacement	$ 167,055	$ 780,249	$ 438,746	$ 1,386,050	$ 1,386,050	$ 209,615	$ 1,161,403	$ 80,392	$ 1,451,410	$ 376,670	$ 2,460,790	No
54	Ludington	Ludington Site Commons	(12736) Ludington 1-6 DCS Control Relay Replacement	$ 62,764	$ 1,648,169	$ 4,771,901	$ 6,482,834	$ 4,298,990	$ 670,551	$ 2,971,797	$ 2,906,676	$ 6,549,024	$ 733,315	$ 12,298,543	No
55	Ludington	Ludington Site Commons	(6325) LPS Replace Barrier Net Panels	$ 705,769	$ 679,115	$ 829,725	$ 2,214,609	$ 2,214,609	$ 151,266	$ 400,010	$ 369,000	$ 920,276	$ 857,035	$ 2,277,850	No
56	Ludington	Ludington Site Commons	(6376) LPS Governor Replacement	$ 215,247	$ 474,166	$ 1,915,833	$ 2,605,246	$ 2,030,496	$ 183,981	$ 2,026,247	$ 2,125,719	$ 4,335,947	$ 399,228	$ 6,541,965	No
57	Ludington	Ludington Site Commons	B-PH-00161: LPS - Unit 1 Pony Motor Overhaul	$ (64,121)	$ 54,168	$ 237,332	$ 227,379	$ 227,379	$ -	$ 2,266,667	$ 2,800,000	$ 5,066,667	$ (64,121)	$ 5,358,167	No
58	Ludington	Ludington Site Commons	(11799) LPS Commons Station Power Transformer Life Cycle Management	$ -	$ 178,500	$ 1,150,000	$ 1,328,500	$ 983,500	$ -	$ 442,156	$ 643,137	$ 1,085,293	$ -	$ 2,413,793	No
59	Battery Storage	Iosco BESS	(13907) Iosco BESS (IRP)	$ 12,353	$ 15,990,033	$ 29,867,096	$ 45,869,482	AFUDC offset	$ 9,107,086	$ 30,052,581	$ 11,457,336	$ 50,617,003	$ 9,119,439	$ 87,367,046	No
60	Battery Storage	Weadock BESS	(13909) Weadock BESS (IRP)	$ 61,228	$ 19,751,334	$ 44,176,110	$ 63,988,672	AFUDC offset	$ 13,010,665	$ 40,561,238	$ 14,934,372	$ 68,506,275	$ 13,071,893	$ 119,423,054	No
61	Generation Admin	Admin	PT-02943: Lakeshore Admin Building	$ -	$ -	$ 2,100,000	$ 2,100,000	$ 1,890,000	$ 1,146,532	$ 3,702,428	$ 38,573	$ 4,887,533	$ 1,146,532	$ 5,841,001	No
62	Generation Admin	Admin	B-PT-00029: Small tools and Equipment - Lab Services	$ 466,416	$ 750,000	$ 750,000	$ 1,966,416	$ 1,966,416	$ 698,656	$ 933,333	$ 700,000	$ 2,331,989	$ 1,165,072	$ 3,133,333	No
63	Generation Admin	Admin	PT-01460: JCW 7&8 RCRA	$ 304,865	$ -	$ -	$ 304,865	$ 304,865	$ 2,915,810	$ -	$ -	$ 2,915,810	$ 3,220,675	$ -	No
64	Generation Admin	Admin	PT-02905: Wastewater Treatment System	$ -	$ -	$ -	$ -	$ -	$ 701,506	$ 12,400,004	$ 9,600,001	$ 22,701,511	$ 701,506	$ 22,000,005	No
65	Generation Admin	EPM	(2712) EPMO Transformation Proj Capital	$ 522,543	$ 850,010	$ 26,250	$ 1,398,803	$ 1,398,803	$ 220,119	$ 393,855	$ 441,702	$ 1,055,676	$ 742,662	$ 1,711,817	No
															No
	Note: Amounts approved in the U-21585 Order are based upon the Company's initial request as well as Mr. Bodiford's exhibits S-16.1 and S-16.2														No

Matthew Bandyk, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7032
mbandyk@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Principal Associate*, January 2025 – Present.

- Performs financial analysis for clients in regulatory cases involving utility cost of capital.
- Summarizes complex technical concepts to clients, regulators, and public audiences through papers, presentations, testimony, and meetings.
- Creates, uses, and maintains spreadsheet-based tools and other analytical platforms to analyze energy technologies, programs, and portfolios.

5 Lakes Energy, Northport, MI. *Consultant,* September 2021 – December 2024

- Provided public policy recommendations and financial analysis for nonprofit energy advocacy and government clients.
- Served as expert witness in testimony in Michigan Public Service Commission rate cases; testimony contributed to hundreds of millions of dollars in ratepayer savings from the outcome of cases.
- Frequently used Microsoft Excel for testimony and projects, such as designing financial models for the City of Ann Arbor.
- Coordinated the writing and research for major reports for clients, such as the Citizens Utility Board of Michigan's Utility Performance Report and Evergreen Collaborative's Michigan Clean Energy Framework.
- Served as communications strategist for the Michigan Energy Innovation Business Council, including writing social media, blog posts on utility regulation and policy issues, enterprise articles in publications like Utility Dive, and op-eds in newspapers like the Detroit Free Press and the Detroit News.
- Significantly expanded contract work for 5 Lakes Energy by bringing in clients from my independent consultancy.

Bandyk Consulting LLC, Royal Oak, MI. *Clean Energy Consultant,* January 2019 – September 2021

- Performed communications and regulatory engagement strategy, including writing comments in regulatory cases, for clients such as the Citizens Utility Board of Michigan and the Michigan Energy Innovation Business Council.

Atwell LLC, Southfield, MI. *Financial Services Manager*, May 2018 – January 2019.

- Purchased long-lived assets to support Atwell's work in environmental and engineering project consulting.
- Performed financial analysis to overhaul company's asset leasing policies with goal of saving up to ~$100k per year by improving asset life.

Environmental Defense Fund, Toledo, OH. *Climate Corps Fellow,* Summer 2017

- Built financial valuation tool for payback, NPV and IRR of solar arrays planned by client, determining best ROI for about $300,000 in solar investments.
- Designed energy use tracking system for the largest private low-income housing provider in Toledo, Ohio; system saved hundreds of work hours annually.

DTE Energy, Detroit, MI. *MBA Student Consultant,* March 2017 – April 2017

- Performed market and regulatory compliance research on original proposal for DTE to enter the corporate renewable energy space; presented to company leadership.
- Designed tariff to add wind/solar and cut rates by 20% compared to DTE's green tariff.

S&P Global Market Intelligence/SNL Financial, Arlington, VA. *Reporter,* June 2010 – August 2016

- Used Excel analysis of power plant output and commodity price databases to create actionable intelligence about new trends in the energy industry for clients.
- Wrote articles on utilities, power plants, energy efficiency and regulation for subscription website read daily by thousands of energy and investment professionals.

EDUCATION

University of Michigan Stephen M. Ross School of Business, Ann Arbor, MI
Master of Business Administration, 2018

Davidson College, Davidson, NC
Bachelor of Arts in Political Science, 2006; *cum laude*

Society for Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst, 2025

TESTIMONY

Michigan Public Service Commission (Docket U-21860): Direct Testimony of Matthew J. Bandyk regarding the application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy. August 22, 2025.

California Public Utilities Commission (Docket A.25-03-013): Direct Testimony of Matthew J. Bandyk regarding San Diego Gas and Electric Company 2026 Cost of Capital. On behalf of Utility Consumers' Action Network. July 30, 2025.

Michigan Public Service Commission (Docket U-21806): Direct Testimony of Matthew J. Bandyk regarding the application of Consumers Energy Company for authority to increase its rates for the

distribution of natural gas and for other relief. On behalf of Citizens Utility Board of Michigan. April 23, 2025.

Michigan Public Service Commission (Docket U-21585): Direct Testimony of Matthew J. Bandyk regarding Consumers Energy Company's application for authority to increase its rates for the generation and distribution of electricity and for other relief. On behalf of Citizens Utility Board of Michigan, Natural Resources Defense Council and Michigan Environmental Council. September 27, 2024.

Michigan Public Service Commission (Docket U-21534): Direct Testimony of Matthew J. Bandyk regarding DTE Electric Company's application to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority. On behalf of Citizens Utility Board of Michigan and Michigan Environmental Council. July 25, 2024.

Michigan Public Service Commission (Docket U-21555): Direct Testimony of Matthew J. Bandyk regarding Upper Peninsula Power Company's application for authority to increase its rates for the generation and distribution of electricity and for other relief. On behalf of Citizens Utility Board of Michigan. July 19, 2024.

Michigan Public Service Commission (Docket U-21540): Direct Testimony of Matthew J. Bandyk regarding Michigan Gas Utilities Corporation's application for authority to increase retail natural gas rates and for other relief. On behalf of Citizens Utility Board of Michigan. June 28, 2024.

Michigan Public Service Commission (Docket U-21291): Direct Testimony of Matthew J. Bandyk regarding DTE Gas Company's application for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority. On behalf of Citizens Utility Board of Michigan. May 7, 2024.

Michigan Public Service Commission (Docket U-21490): Direct Testimony of Matthew J. Bandyk regarding Consumers Energy Company's application for authority to increase its rates for the distribution of natural gas and for other relief. On behalf of Citizens Utility Board of Michigan. April 22, 2024.

Michigan Public Service Commission (Docket U-21389): Direct Testimony of Matthew J. Bandyk, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan regarding Consumers Energy Company's application for authority to increase its rates for the generation and distribution of electricity and for other relief. On behalf of Michigan Environmental Council. August 29, 2023.

Michigan Public Service Commission (Docket U-21048): Direct Testimony of Matthew J. Bandyk regarding Consumers Energy Company's application for approval to implement a power supply cost recovery plan for the 12 months ending December 31, 2022. On behalf of Citizens Utility Board of Michigan. April 29, 2022.

Resume updated September 2025

Exhibit CUB-2

Overall Rate of Return

(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Capital Structure				Weighted Cost	
Description	**Amount ($000,000) (1)**	**Percent Permanent Capital (2)**	**Percent of Total Capital**	**Cost Rate %**	**Permanent Capital (7)**	**Total Cost -8%**
Long-Term Debt	$13,916	50.00%	42.40%	4.54%	2.23%	1.93%
Preferred Stock	0	0.00%	0.00%	4.50%	0.01%	0.00%
Common Shareholder's Equity	13,916	50.00%	42.40%	9.22%	5.20%	3.91%
Total Permanent Capital	$27,832	100.00%	84.80%			
Short-Term Debt	148		0.45%	4.92%		0.02%
Deferred Income Taxes	4,692		14.30%	0.00%		0.00%
Investment Tax Credit						
Long-Term Debt	74		0.23%	4.54%		0.01%
Preferred Stock	0		0.00%	4.50%		0.00%
Common Equity	74		0.23%	10.25%		0.02%
Total	$32,820		100.00%			5.89%

Exhibit CUB-3

Equity Risk Premium and Corresponding Risk-Free Rates

Damodaran[1]	**Equity Risk Premium**
Damodaran (Trailing 12 months with sustainable payout)	**3.68%**
Damodaran (Trailing 12 months)	**3.94%**
Damodaran (smoothed)	**5.37%**
Damodaran (normalized)	**3.57%**
Damodaran (net cash yield)	**3.68%**
Average	**4.05%**

Kroll[3]

Kroll	**5.0%**

	Risk-Free Rate
Damodaran	**4.23%**
Kroll[2]	**4.76%**

[1] Aswath Damodaran. "Implied ERP by month for previous months (September 2008- Current)." https://pages.stern.nyu.edu/~adamodar/New_Home_Page/home.htm. Accessed September 2025.
[2] 20-year Treasury yield as of 9/5/25. https://www.cnbc.com/quotes/US20Y. Kroll recommends "using the spot 20-year U.S. Treasury yield as the proxy for the risk-free rate if the prevailing spot yield as of the valuation date is higher than the Kroll normalized U.S. risk-free rate of 3.5%."
[3] Kroll, "Kroll Recommended U.S. Equity Risk Premium and Corresponding Risk-Free Rates to be Used in Computing Cost of Capital: January 2008 - Present," Sept. 2, 2025. https://www.kroll.com/en/reports/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates.

Exhibit CUB-4

Beta

Company	[1] Bloomberg Beta Coefficient	[2] Raw Beta	[3] Value Line Beta Coefficient	[4] Raw Beta
Alliant Energy Corporation	0.77	0.66	0.95	0.92
Ameren Corporation	0.73	0.60	0.9	0.85
American Electric Power Company, Inc.	0.74	0.61	0.85	0.77
Avista Corporation	0.74	0.61	0.95	0.92
Dominion Resources, Inc.	0.69	0.54	0.9	0.85
DTE Energy Company	0.8	0.70	1	1.00
Duke Energy Corporation	0.7	0.55	0.9	0.85
Entergy Corporation	0.84	0.76	1	1.00
Evergy, Inc.	0.77	0.66	0.95	0.92
IDACORP, Inc.	0.77	0.66	0.85	0.77
NextEra Energy, Inc.	0.8	0.70	1.05	1.08
NorthWestern Corporation	0.85	0.78	1	1.00
OGE Energy Corporation	0.9	0.85	1.05	1.08
Pinnacle West Capital Corporation	0.8	0.70	0.95	0.92
TXNM Energy	0.81	0.72	0.9	0.85
Portland General Electric Company	0.77	0.66	0.95	0.92
PPL Corporation	0.91	0.87	1.1	1.15
Southern Company	0.76	0.64	0.95	0.92
Xcel Energy Inc.	0.72	0.58	0.85	0.77
Average	0.78	0.68	0.95	0.92

[1]	Exhibit A-14, Sched. D-5, p. 6.
[2]	([1]-0.33)/0.67
[3]	Exhibit A-14, Sched. D-5, p. 9.
[4]	([3]-0.35)/0.65

Exhibit CUB-5

CAPM Analysis

ERP (Damodaran)[1]	Risk-free rate (Damodaran)[2]	Value Line Beta[3]	Cost of Equity[4]
4.05%	4.23%	0.92	7.97%

ERP (Damodaran)	Risk-free rate (Damodaran)	Bloomberg Beta[5]	Cost of Equity
4.05%	4.23%	0.68	6.96%

ERP (Kroll)[6]	Risk-free rate (Kroll)[7]	Value Line Beta	Cost of Equity
5.00%	4.76%	0.92	9.37%

ERP (Kroll)	Risk-free rate (Kroll)	Bloomberg Beta	Cost of Equity
5.00%	4.76%	0.68	8.13%

[1] Exhibit CUB-3.
[2] Id.
[3] Exhibit CUB-4.
[4] = Risk-free rate plus (Beta times ERP)
[5] Exhibit CUB-4.
[6] Exhibit CUB-3.
[7] Id.

Exhibit CUB-6

Long-Term Growth Rate Sources

Nominal GDP annual average growth rate 2028-2035[1]	**3.80%**
Real GDP annual average growth, 2028-2035[2]	1.80%
Inflation annual average growth rate, 2028-2035 (GDP price index)[3]	2.0%

[1] Congressional Budget Office. *The Budget and Economic Outlook: 2025 to 2035*. Table C-1. January 2025. https://www.cbo.gov/publication/61172#_idTextAnchor004.
[2] Id.
[3] Id

Exhibit CUB-7

DCF (with Earnings Growth Rates)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
		Annualized Dividend	High Closing Price	Low Closing Price	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	S&P Capital IQ Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Long-Term Growth	Cost of Equity
Alliant Energy Corporation	LNT	$2.03	$66.97	$64.43	$65.70	3.09%	3.19%	6.70%	6.81%	6.00%	6.50%	3.80%	9.15%
Ameren Corporation	AEE	$2.84	$103.26	$99.95	$101.61	2.80%	2.89%	6.70%	6.88%	6.50%	6.69%	3.80%	9.00%
American Electric Power Company, Inc.	AEP	$3.72	$115	$108.36	$111.68	3.33%	3.44%	6.30%	6.69%	6.50%	6.50%	3.80%	9.40%
Avista Corporation	AVA	$1.96	$38.25	$36.23	$37.24	5.26%	5.42%	6.10%	5.88%	5.50%	5.83%	3.80%	10.84%
Dominion Resources, Inc.	D	$2.67	$62.10	$58.78	$60.44	4.42%	4.66%	13.60%	13.49%	6.00%	11.03%	3.80%	14.25%
DTE Energy Company	DTE	$4.36	$141.49	$135.49	$138.49	3.15%	3.25%	7.60%	7.87%	4.50%	6.66%	3.80%	9.34%
Duke Energy Corporation	DUK	$4.18	$125.93	$120.65	$123.29	3.39%	3.50%	6.30%	6.32%	6.00%	6.21%	3.80%	9.22%
Entergy Corporation	ETR	$2.40	$91.62	$87.20	$89.41	2.68%	2.78%	9.50%	8.88%	3.00%	7.13%	3.80%	9.24%
Evergy, Inc.	EVRG	$2.67	$73.27	$71.13	$72.20	3.70%	3.81%	5.70%	5.72%	7.50%	6.31%	3.80%	9.62%
IDACORP, Inc.	IDA	$3.44	$128.05	$124.05	$126.05	2.73%	2.83%	8.50%	8.23%	6.00%	7.58%	3.80%	9.65%
NextEra Energy, Inc.	NEE	$2.27	$76.51	$70.53	$73.52	3.09%	3.21%	7.80%	7.11%	8.50%	7.80%	3.80%	10.21%
NorthWestern Corporation	NWE	$2.64	$58.48	$54.54	$56.51	4.67%	4.80%	6.10%	5.94%	4.50%	5.51%	3.80%	9.97%
OGE Energy Corporation	OGE	$1.69	$45.90	$43.90	$44.90	3.76%	3.88%	6.10%	5.92%	6.50%	6.17%	3.80%	9.58%
Pinnacle West Capital Corporation	PNW	$3.58	$93.78	$88.73	$91.26	3.92%	4.01%	2.10%	5.55%	5.00%	4.22%	3.80%	8.14%
TXNM Energy	TXNM	$1.63	$57.13	$56.50	$56.82	2.87%	2.94%	3.00%	6.55%	4.50%	4.68%	3.80%	7.44%
Portland General Electric Company	POR	$2.00	$43.08	$41.93	$42.51	4.71%	4.83%	3.40%	6.54%	6.50%	5.48%	3.80%	9.98%
PPL Corporation	PPL	$1.09	$37.24	$35.78	$36.51	2.99%	3.09%	6.80%	7.27%	7.50%	7.19%	3.80%	9.60%
Southern Company	SO	$2.88	$96	$91.51	$93.76	3.07%	3.17%	6.50%	6.33%	6.50%	6.44%	3.80%	9.09%
Xcel Energy Inc.	XEL	$2.28	$74.26	$71.69	$72.98	3.12%	3.23%	6.90%	7.26%	7.00%	7.05%	3.80%	9.64%
Average													**9.65%**

[1] Exhibit A-14, Sched. D-5, p. 3.
[2] Source: Yahoo! Finance covering 30-day period ending Sept. 4, 2025.
[3] Id.
[4] Average of [2] and [3]
[5] [1] divided by [4]
[6] [5] times [1+(0.5*[10])]
[7] Exhibit A-14, Sched. D-5, p. 3.
[8] Id.
[9] Value Line
[10] Average of [7], [8] and [9]
[11] Source: Exhibit CUB-6
[12] [6] plus (0.8 times [10]) plus (0.2 times [11])

Exhibit CUB-8: DCF (with Dividend Growth Rates)

		[1] Annualized Dividend	[2] High Closing Price	[3] Low Closing Price	[4] Average Stock Price	[5] Dividend Yield	[6] Expected Dividend Yield	[7] Value Line Dividend Growth	[8] Long-Term Growth	[9] Cost of Equity
Alliant Energy Corporation	LNT	$2.03	$66.97	$64.43	$65.70	3.09%	3.18%	6.00%	3.80%	8.74%
Ameren Corporation	AEE	$2.84	$103.26	$99.95	$101.61	2.80%	2.89%	6.50%	3.80%	8.85%
American Electric Power Company, Inc.	AEP	$3.72	$115	$108.36	$111.68	3.33%	3.42%	5.50%	3.80%	8.58%
Avista Corporation	AVA	$1.96	$38.25	$36.23	$37.24	5.26%	5.37%	4.00%	3.80%	9.33%
Dominion Resources, Inc.	D	$2.67	$62.10	$58.78	$60.44	4.42%	N/A	N/A	3.80%	N/A
DTE Energy Company	DTE	$4.36	$141.49	$135.49	$138.49	3.15%	3.20%	3.00%	3.80%	6.36%
Duke Energy Corporation	DUK	$4.18	$125.93	$120.65	$123.29	3.39%	3.45%	3.50%	3.80%	7.01%
Entergy Corporation	ETR	$2.40	$91.62	$87.20	$89.41	2.68%	2.76%	5.50%	3.80%	7.92%
Evergy, Inc.	EVRG	$2.67	$73.27	$71.13	$72.20	3.70%	3.83%	7.00%	3.80%	10.19%
IDACORP, Inc.	IDA	$3.44	$128.05	$124.05	$126.05	2.73%	2.80%	5.50%	3.80%	7.96%
NextEra Energy, Inc.	NEE	$2.27	$76.51	$70.53	$73.52	3.09%	3.23%	9.50%	3.80%	11.59%
NorthWestern Corporation	NWE	$2.64	$58.48	$54.54	$56.51	4.67%	4.71%	1.50%	3.80%	6.67%
OGE Energy Corporation	OGE	$1.69	$45.90	$43.90	$44.90	3.76%	3.82%	3.00%	3.80%	6.98%
Pinnacle West Capital Corporation	PNW	$3.58	$93.78	$88.73	$91.26	3.92%	3.95%	1.50%	3.80%	5.91%
TXNM Energy	TXNM	$1.63	$57.13	$56.50	$56.82	2.87%	2.94%	5.00%	3.80%	7.70%
Portland General Electric Company	POR	$2.00	$43.08	$41.93	$42.51	4.71%	4.83%	5.50%	3.80%	9.99%
PPL Corporation	PPL	$1.09	$37.24	$35.78	$36.51	2.99%	3.08%	6.50%	3.80%	9.04%
Southern Company	SO	$2.88	$96	$91.51	$93.76	3.07%	3.13%	3.50%	3.80%	6.69%
Xcel Energy Inc.	XEL	$2.28	$74.26	$71.69	$72.98	3.12%	3.23%	6.50%	3.80%	9.19%
Average										**8.26%**

[1]	Exhibit A-14, Sched. D-5, p. 3.
[2]	Source: Yahoo! Finance covering 30-day period ending Sept. 4, 2025.
[3]	Id.
[4]	Average of [2] and [3]
[5]	[1] divided by [4]
[6]	[5] times [1+(0.5*[10])]
[7]	Value Line
[8]	Source: Exhibit CUB-6
[9]	[6] plus (0.8 times [7]) plus (0.2 times [8])

Exhibit CUB-9

Interest Coverage Ratio

Tax Rate[1]

a)	State Tax Rate	0.0524
b)	Local Tax Rate	0.0016
c)	Federal Tax Rate	0.21
d)	Total Tax Rate	0.264

Interest coverage ratio with Company-proposed debt/equity ratio and cost of equity

	Weight	Cost	Wtd cost[2]	tax factor	pre-tax wtd cost[3]
debt	0.4911	0.0454	0.02229594	1	0.02229594
equity	0.5075	0.1025	0.05201875	1.358695652[4]	0.070677649
				sum	0.092973589
				interest coverage[5]	**4.169978456**

Interest coverage ratio with Bandyk-recommended debt/equity ratio and cost of equity

	Weight	Cost	Wtd cost	tax factor	pre-tax wtd cost
debt	0.5	0.0434	0.0217	1	0.0217
equity	0.5	0.097	0.0485	1.358695652	0.065896739
				sum	0.087596739
				interest coverage	**4.036716089**

[1] Exhibit A-3, Sched. C-2.
[2] Weight times cost.
[3] Weighted cost times tax factor.
[4] 1/(1-d)
[5] Sum divided by debt pre-tax weighted cost.

Exhibit CUB-10

CAPM for U.S. Stock Market

ERP (Damodaran)[1]	Risk-free rate (Damodaran)[2]	Beta	Cost of Equity[3]
4.05%	4.23%	1	8.28%

ERP (Damodaran)	Risk-free rate (Damodaran)	Beta	Cost of Equity
4.05%	4.23%	1	9.76%
Average			**9.02%**

[1] Exhibit CUB-3.
[2] Id.
[3] = Risk-free rate plus (Beta times ERP)

Douglas B. Jester

Personal Information

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517-337-7527
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Professional experience

January 2011 – present — 5 Lakes Energy

Managing Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan. Expert witness in more than 70 electric utility regulation cases in Michigan and approximately 15 cases in other states.

February 2010 - December 2010 — Michigan Department of Energy, Labor and Economic Growth

Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 — Rose International

Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - 2015 IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2022).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:

- Co-chair of Strategic Great Lakes Fishery Management Plan working group
- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts of power plants on natural resources and recreation.

Education

1991-1995 Michigan State University
PhD Candidate, Environmental Economics
Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia
Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University
MS Fisheries and Wildlife Sciences
MS Statistics and Operations Research

1971-1974 New Mexico State University
BIS Mathematics, Computer Science, Biology, and Fine Arts

Citizenship and Community Involvement

Youth Soccer Coach, East Lansing Soccer League, 1987-89

Co-organizer, East Lansing Community Unity, 1992-1993

Bailey Community Association Board, 1993-1995

East Lansing Commission on the Environment, 1993-1995

East Lansing Street Lighting Advisory Committee, 1994

Councilmember, City of East Lansing, 1995-1999

Mayor, City of East Lansing, 1995-1997

East Lansing Downtown Development Authority Board Member, 1995-1999

East Lansing Transportation Commission, 1999-2004

East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004

Lansing – East Lansing Smart Zone Board of Directors, 2007-2017

Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012

East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – 2018.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – 2018.

East Lansing Downtown Management Board and Chair, 2010 – 2016

East Lansing City Center Condominium Association Board Member, 2015 – 2022.

City of East Lansing Advisory Commissioner to the Lansing Board of Water and Light, 2017 – 2023

State of Michigan UP Energy Task Force, 2019-2021, appointed by Governor Whitmer.

State of Michigan Dam Safety Committee, 2020-2021

State of Michigan Council on Climate Solutions, Energy Production, Transmission, Distribution, and Storage Workgroup Co-Chair, 2021-present.

Board and Executive Committee Member, For Love of Water (FLOW), 2019 - present

U-21870

Projected EV Load Growth Managed Under the Company's Transportation Electrification Plan (TEP) and a Comparison to Forecasted EV Adoption Growth

Exhibit A-165 (JAM-3) presents a cost-benefit analysis for the Company's TEP until 2035. The following is the predicted load managed under TEP programs until 2030:

The above table shows that the load managed under TEP programs is expected to grow by roughly **8.5x** between now and 2030. Since off-peak and on-peak usage each grow by the same factor, the Company evidently assumes its EV load management strategies will remain as effective as they have been thus far.

Meanwhile, Company Witness Myrom states[1] that EV load growth remains on pace for the "500K EV" by 2030 scenario used in the Company's 2021 Integrated Resource Plan (Case No. U-21090), compared to the roughly 40,000 EVs observed in late 2024, with different forecasts varying between 470,000 and 630,000 EVs by 2030—an increase of between **11.75x** and **15.75x**.

In other words, the Company's own projections indicate that the EV load managed under its TEP programs is expected to lag behind overall EV load growth to a considerable extent.

[1] Direct Testimony of Company Witness Jeffrey A. Myrom, Pages 10-11.

U21870-MNSC-CE-0569
Page **1** of **1**

Question:

For questions 17-26 please refer to the Company's Transportation Electrification Plan (TEP), cited in the Direct Testimony of Jeffrey A. Myrom, Page 4, Footnote 2.
18. As of the most recent date available, please provide the latest information regarding participation in the PowerMIDrive program, including:
a. Updated numbers of rebates issued for each customer segment.
b. Enrollment figures and participation levels in any associated managed charging or incentive programs.
c. Geographic distribution of rebates issued, by ZIP Code if available.

Response:

a. As of September 8, 2025, the lifetime number of rebates issued per customer segment are as follows:
    a. Residential: 5,835 Rebates.
    b. Multifamily: 65 Rebates.
    c. Community: 81 Rebates.
    d. Workplace: 181 Rebates.
    e. Overnight Destination: 136 Rebates.
    f. Public DCFC: 98 Rebates.

b. Residential Managed Charging Participation:
    a. 2,970 Total Customers Actively Enrolled in Smart Charge Incentive (SCI).
    b. 3,870 Total Customers Completed + Graduated from 12 months SCI.
    c. 134 Total Customers Enrolled in SCI but removed prior to completion of 12-month SCI (e.g. relocation outside of electric territory).
    d. 181 Fleet Carma incentives from the pilot phase.

c. Please see the attached file for the geographic distribution of rebates by ZIP Code.

Witness: Jeffrey A. Myrom
Date: September 8, 2025

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Page **1** of **1**

Question:

25. Please describe in detail the Company's plans to develop telematics and V2X capabilities in support of managed charging, including:

a. Any analyses, pilot programs, vendor partnerships, or RFPs currently under development.

b. The anticipated timeline for telematics-based program design and deployment.

c. How telematics data will be used to influence and verify off-peak charging behavior.

d. Any analysis of costs, benefits, and data privacy considerations associated with telematics-enabled managed charging.

Response:

The Company presently has no plans to develop telematics and V2X capabilities. As stated on page 38 of the 2024 Transportation Electrification Plan (TEP), we are monitoring developments to see how these technologies mature.

Witness: Jeffrey A. Myrom
Date: September 15, 2025

U21870-MNSC-CE-0578
Page **1** of **2**

Question:

27. Please refer to page 44 of the TEP, which projects between 1,500 and1,850 additional DCFC sites requiring 1 MW or greater service. Please describe in detail the Company's proactive efforts, and provide any associated analyses or planning documents, to prepare for this projected influx of requests, including:

    a. Current DCFC interconnection queue statistics, including the number of 1MW+ requests received, pending, and fulfilled.

    b. System planning analyses and capacity maps/studies produced to date.

    c. Any data and conclusions related to the EV propensity study referenced in the Direct Testimony of Jennifer M. Partlan, page 114.

    d. Steps being taken to mitigate the impacts of the 24-month backlog in transformer procurement and installation.

    e. Any prioritization or queue management processes established for DCFC interconnection requests.

Response:

a. Presently there are 11 DCFC sites with a nameplate capacity of 1 MW or greater in progress. There are an additional 15 NEVI Round 2 sites anticipated that will also have nameplate capacity near or greater than 1 MW.

b. The Company uses its CYME software to model its load flow assumptions of the LVD system on an annual basis, as described on page 113 of my direct testimony. The Company has developed initial hosting capacity maps, and is planning to publish more detailed hosting capacity maps in the near future as discussed by Company witness Kelly on page 70, line 9, through page 71, line 21, of his direct testimony. Additionally, the Company will begin publishing updated hosting capacity maps beginning on October 1, 2025, as directed by the Commission in its July 10, 2025 Order in Case No. U-20147.

c. Please see Attachment 1 to this response, which describes the propensity study referenced in my direct testimony.

d. Please see Company witness Kelly's direct testimony, page 186, line 4 through page 188, line 2. Furthermore, the Supply Chain team is currently implementing a three-pronged approach to reduce procurement lead times:

    1) **Diversifying the Supply Base** – This includes onboarding international suppliers to expand sourcing options and reduce dependency on any single region or vendor.

2) **Establishing Long-Term Contracts** – The intention is to reduce spot-buying, which risk extended lead times and lower prioritization in supplier production schedules. Long-term agreements ensure more reliable slot allocation and improved responsiveness.

3) **Sharing Long-Term Demand Forecasts** – By projecting and sharing demand 3 to 5 years into the future, we are enabling suppliers to plan more effectively and align their capacity with our strategic needs.

e. Customer service requests for DCFC follow the same process as other new service requests.

Witness: Jennifer M Partlan
Date: September 16, 2025

Question:

32. Please refer to the Direct Testimony of Jeffrey A. Myrom, pages 6-10. Please provide the most recent available data on participation in the Company's TEP programs by customer income level or disadvantaged community (DAC) status, including:

a. The number of rebates issued to income-qualified customers, broken out by program and customer segment.

b. Any analyses the Company has conducted regarding barriers to participation among low-income or DAC customers.

c. Any current or planned program modifications intended to expand access for these customer groups.

d. Any additional TEP funds the Company plans to reallocate from DCFC make-ready costs to support low-income and disadvantaged customers and communities.

Response:

a. As of September 8, 2025, a total of 26 residential rebates have been issued to income-qualified customers.

    a. Other public/fleet categories have seen a number of rebates awarded in MIEJ and/or prior EJ40 regions as follows:

        i. Multifamily: 34 Rebates.

        ii. Community: 24 Rebates.

        iii. Workplace: 65 Rebates.

        iv. Overnight Destination: 26 Rebates.

        v. Public DCFC: 11 Rebates.

b. The Company believes that barriers to participation include the following: (1) customers who do not yet own or lease an EV and are thus not eligible for participation, and (2) lack of charging infrastructure at equitable charging locations like multifamily properties, community charging, and workplace charging. The Company already has rebate programs attempting to address the aforementioned charging infrastructure and believes that EV adoption among lower income customers will increase as more used EVs hit the market.

c. The use of a bring-your-own-cord model in multifamily and workplace situations (in addition to community charging which already allows this option) was proposed in the present case to make infrastructure development costs more affordable and planning even easier and thus further accelerate charging infrastructure.

d. At this time, the Company anticipates that the DCFC make-ready funds from the remaining pilot budget will be fully utilized, and thus not available to support low-income programs as was possible under the PowerMIFleet pilot phase. The PowerMIFleet pilot's focus on Level 2 (L2) charging is what enabled make-ready cost savings compared to budget projections at the start of the pilot, but DCFC projects have higher make ready costs than L2.

Witness: Jeffrey A. Myrom
Date: September 8, 2025

Question:

19. As of the most recent date available, please provide the latest information regarding participation in the PowerMIFleet program, including:

a. Updated numbers of rebates issued for each customer segment.

b. A table summarizing each fleet assessment, including the number and percentage of each fleet's vehicles recommended for electrification.

Response:

a. As of September 8, 2025, the number of PowerMIFleet program rebates per customer segment are as follows:
    a. **Education**: 41 Fleet L2 Rebates and 6 Fleet DC Rebates.
    b. **Healthcare:** 1 Fleet L2 Rebate.
    c. **Manufacturing:** 6 Fleet L2 Rebates.
    d. **Municipal/Govt:** 16 Fleet L2 Rebates.
    e. **Non-Profit:** 7 Fleet L2 Rebates.
    f. **Retail:** 55 Fleet L2 Rebates and 5 Fleet DC Rebates.
    g. **Rideshare (Municipal):** 6 Fleet L2 Rebates.
    h. **Transit:** 11 Fleet L2 Rebates and 2 Fleet DC Rebates.

b. Please see the attached table with Fleet Assessment Summary.

Witness: Jeffrey A. Myrom
Date: September 15, 2025

	A	B	C
1	**PowerMIFleet Assessment Participant Organization**	**Customer Segment**	**Percent of Fleet Recommended to Electrify**
2	**Ludington School District**	Education	8%
3	**Meijer**	Retail	8%
4	**Spectrum Health**	Healthcare	10%
5	**Homer Community Schools**	Education	11%
6	**Hopkins Public Schools**	Education	13%
7	**Hidden Lake Gardens (MSU)**	Education	17%
8	**Traverse City Public Schools**	Education	17%
9	**City of Grand Rapids**	Municipal/Govt	18%
10	**Aquinas College**	Education	20%
11	**Rowleys Wholesale**	Retail	20%
12	**Zoetis**	Retail	20%
13	**City of Kalamazoo**	Municipal/Govt	20%
14	**City of East Grand Rapids**	Municipal/Govt	22%
15	**FireKeeper's Casino**	Retail	23%
16	**Kentwood Public Schools**	Education	23%
17	**Mott College**	Education	25%
18	**City of Boyne**	Municipal/Govt	27%
19	**MTA - Flint**	Transit	27%
20	**Hudsonville Public Schools**	Education	29%
21	**Kirtland Community College**	Education	31%
22	**Western Michigan University**	Education	33%
23	**Michigan State University**	Education	33%
24	**Padnos**	Retail	33%
25	**Alma College**	Education	34%
26	**Rockford Public Schools**	Education	35%
27	**City of Muskegon**	Municipal/Govt	35%
28	**City of Harrisville**	Municipal/Govt	36%
29	**Grand Rapids (GRR) Airport**	Transit	36%
30	**DNR - State of Michigan**	Municipal/Govt	37%
31	**University of Michigan Flint**	Education	37%
32	**Jackson Public Schools**	Education	38%
33	**Balkema Sitework**	Retail	40%
34	**Meridian Township**	Municipal/Govt	40%
35	**Mason County Eastern Schools**	Education	42%
36	**West Shores ESD**	Education	42%
37	**David's House Ministries**	Retail	47%
38	**City of Wyoming**	Municipal/Govt	48%
39	**JP O'Sullivan Distributing**	Retail	48%
40	**Coyne Oil**	Retail	49%
41	**Jackson Area Transit Authority (JATA)**	Transit	50%
42	**Vanderbilt Area Schools**	Education	50%
43	**CS Erickson**	Retail	52%

	A	B	C
44	**Bronson Healthcare Group**	Healthcare	54%
45	**Ashley Community Schools**	Education	56%
46	**City of Linden**	Municipal/Govt	58%
47	**Merrill Community School District**	Education	58%
48	**Hand2Hand**	Retail	60%
49	**Viking Products**	Retail	63%
50	**Eaton County**	Municipal/Govt	71%
51	**Saginaw Stars**	Transit	74%
52	**Dean Transportation - Corporate**	Transit	79%
53	**Weinstein Electric**	Retail	86%
54	**Home Repair Services of Kent County**	Retail	89%
55	**Kids Food Basket**	Retail	92%
56	**Comstock Public Schools**	Municipal/Govt	93%
57	**Alma Transportation Center**	Transit	100%
58	**City of Midland Dial-A-Ride**	Transit	100%
59	**Clare County Transit**	Transit	100%
60	**Holland Charter Township**	Municipal/Govt	100%
61	**Inland Lakes Public Schools**	Education	100%
62	**Ionia Dial A Ride**	Transit	100%
63	**Roscommon County Transportation Authority**	Transit	100%
64	**Tawas Police Department**	Municipal/Govt	100%

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Page **1** of **1**

Question:

31. Please provide any analyses or planning documents describing how the Company intends to achieve the 30% fleet electrification goal by 2030, in light of Exhibit A-104 (QAG-5).

Response:

The Company is currently reevaluating its 30% fleet electrification goal by 2030. To achieve the 30% electrification goal, the Company would need to purchase suitable electric units (PHEVs, BEVs and/or ePTOs) at a rate that the current marketplace for electric units does not support. As the Company reevaluates the 30% fleet electrification goal, it continues to acquire electric units to replace ICE units in accordance with its Fleet Electrification Filter as outlined in the direct testimony of Quentin A. Guinn, pages 62 and 63.

Witness: Quentin A. Guinn
Date: September 10, 2025

U21870-MNSC-CE-0577
Page **1** of **1**

Question:

26. Please identify and describe in detail the Company's efforts to implement battery arbitrage technologies at DCFC stations to mitigate on-peak charging.

Response:

In Case No. U-21585, the Company proposed a rebate for battery-integrated Direct Current Fast Chargers (DCFCs). Please see that docket for details regarding the proposal. That request was not approved as part of the permanent TEP customer programs in the final Order in Case No. U-21585. No additional proposals have been made.

Witness: Jeffrey A. Myrom
Date: September 8, 2025

U21870-MNSC-CE-0579
Page **1** of **1**

Question:

28. Please refer to the Direct Testimony of Jeffrey A. Myrom, page 12, lines 9-18. Please provide all internal analyses, memoranda, or stakeholder feedback that informed the Company's decision not to propose any TEP budget increases in this case.

Response:

Multiple rebate projects have been delayed due to Federal and State funding developments, and the queue of rebate projects applied for has not exceeded the annual budget. Thus, current market conditions alone have led us to believe that any additional funding requests can wait until at least the next rate case because rebate funding is not a constraint.

Witness: Jeffrey A. Myrom
Date: September 15, 2025

RICHARD J. BUNCH

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206-595-8293

Executive and organizational innovator with expertise in energy technology, finance, utilities and regulation. Leadership experience in academic, non-profit and public sectors. Broad topical and functional expertise in sustainable and socially responsible business and public policy. Demonstrated ability to recruit top performers and build strong teams.

EXPERTISE

- Clean energy project evaluation, development and financing for local governments; utility tariffs and regulatory processes.
- Broad understanding of sustainability and clean energy issues that impact businesses through markets, technology and public policy.
- Integration of clean energy and sustainability into organizational strategy, management and culture through education, training and strategic planning.
- Electric tariff topics including municipal streetlighting, rates and programs affecting low-income customers, service quality and billing rules, infrastructure project coordination with local governments, voluntary green power tariffs, production cost allocation, PSCR reconciliation.

PROFESSIONAL EXPERIENCE

5 Lakes Energy, Lansing, MI, *Lead Consultant, May 2019-present*

Michigan Municipal Association for Utility Issues, Ann Arbor, MI
Founder and Managing Director, 2017-present
Providing collective, expert and focused representation for municipal governments in Michigan Public Service Commission proceedings and in dialog with regulated utilities.

Southeast Michigan Regional Energy Office, Ann Arbor, MI
Executive Director, 2014-2017
Directed coalition of southeast Michigan municipalities cooperating to identify, finance and implement clean energy projects.

University of Michigan, Erb Institute for Global Sustainable Enterprise
Managing Director, 2008-2013
Led world-leading sustainable enterprise program at top-10 business school.

Aspen Institute Business and Society Program, New York
Senior Fellow, 2006-2008
Launched new Corporate Social Responsibility business education program in China in partnership with Chinese business schools, accrediting agency and corporations

Bainbridge Graduate Institute, Bainbridge Island, WA
Executive Director, 2003-2005
Led administration, education, fundraising and communications of fast-growing, startup business school with world-first infusion of sustainability throughout MBA curriculum.

World Resources Institute, Washington, DC
Director of Business Education, 1996-2003
Developed, fundraised and directed international sustainable business education initiatives engaging universities, companies, governments and non-profit leaders.

Washington Public Interest Research Group, Seattle, Washington
Executive Director, 1989-1992

EDUCATION

MBA with Environmental Management Certificate, University of Washington, 1995
BA in Political Science, Yale University, 1985

TRAINING

EUCI Outdoor Street Lighting Conference, June 4-5, 2019, Atlanta.
EUCI Electric Cost-of-Service – Essential Concepts for a Changing Industry Course, July 15-17, 2019, Chicago.
MSU-IPU Accounting and Ratemaking course, September 2020
EUCI Utility Green Tariffs: A to Z course, November 4-5, 2020, online
MSU-IPU Advanced Regulatory Accounting and Auditing course, October 2021
NRRI Regulatory Training Institute, Regulating Public Utility Performance course, 2022
EUCI Advanced Rate Design for Cost Effective Tariffs training, 2024

REGULATORY PROCEEDINGS

Expert Witness, MPSC case U-21860 (DTE Electric general electric rate case, 2025)
Expert Witness, MPSC case U-21585 (Consumers Energy general electric rate case, 2024)
Expert witness, MPSC case U-21534 (DTE Electric general rate case, 2024)
Expert witness, MPSC case U-21389 (Consumers Energy electric rate case, 2023)
Expert witness, MPSC case U-21297 (DTE Electric general rate case, 2023)
Expert witness, MPSC case U-21087 (DTE Electric PrePay, 2021-2022)
Expert witness, MPSC case U-20836 (DTE Electric general rate case, 2022)
Expert witness, MPSC case U-20963 (Consumers Energy electric rate case), 2021.
Expert witness, MPSC case U-20697 (Consumers Energy electric rate case), municipal street lighting tariffs, 2020.
Expert witness, MPSC case U-20530 (I&M PSCR reconciliation
Expert witness, MPSC case U-20561 (DTE Electric general rate case), production allocation, 2019
Expert witness, Kentucky Public Utilities Commission cases 2020-349 and 2020-350, the combined Kentucky Utilities and Louisville Gas & Electric electric and gas rate cases.
Submitted comments, MPSC case U-20147, Electric Distribution Planning. Participated in stakeholder meetings.
Submitted comments, MPSC case U-20629, electric reliability standards. Focused on municipal street lighting reliability standards.
MPSC case U-20134 (Consumers Energy general electric rate case), organized and managed coalition of municipalities intervening to challenge street lighting tariffs.
MPSC cases U-18014 and U-17767, DTE Electric general rate cases, organized and coalition of municipalities challenging street lighting tariffs.

SELECTED RESEARCH AND PUBLICATIONS

"*Corporate Responsibility In a Transitioning Industry: An Automotive Supply Chain Perspective*", Automotive Industry Action Group, 2019. Co-author and researcher.
"*Expect the Unexpected: Building Business Value in a Changing World*", KMPG 2012. Erb Institute (University of Michigan) research team leader and contributor.
Where Will They Lead? China 2008 MBA Student Attitudes about Business & Society. The Aspen Institute, 2008.
"*Beyond Grey Pinstripes: Preparing MBAs for Social and Environmental Stewardship*," World Resources Institute and The Aspen Institute, 1998, 1999, 2001 and 2003. Creator, co-author.
Numerous academic, non-profit and public agency conference and meeting presentations and public testimony.

SERVICE

The Stewardship Network Board of Directors and Treasurer, 2022-present.
Michigan Environmental Council Board of Directors, 2009-present. Treasurer, 2017-2022.
Soulardarity Board of Directors and Secretary, 2018-present. Highland Park, MI.
Washington Public Interest Research Group and WashPIRG Foundation Board of Directors, 1994-present
PIRGIM Education Foundation Board of Directors, 2015-present. Ann Arbor, MI.
MPSC EAAC Data Analysis and Regulatory Review working group, ongoing.
MPSC Low Income Energy Policy Board, ongoing.

U21870-MNSC-CE-0560
Page **1** of **1**

Question:

9. Refer to the Direct Testimony of Kendra K. Grob, pg. 16, 8:10, "DCCP costs are projected to increase using merit salary rate factors of 3.2% for 2024 through the 12 months ending April 30, 2027." However, in Exhibit A-97 (KKG-1), pg.2, line 2, the factors applied to arrive at projected "Merit & Inflation" costs are the inflation factors of 2.1%, 2.4%, and 2.4% for 2025, 2026, and 2027, respectively. Please clarify the discrepancy and confirm which factor is correct.

Response:

Exhibit A-97 (KKG-1), page 2, columns b to h, show what the increase would be for applying inflation rates amounts projected out on 2024 actuals for DCCP and the column i adjustment includes adjustments for change in electric/gas splits, capitalizations, and merit 3.2% adjustment to inflation amounts. Full calculations can be found on WP-KKG-1.

Witness: Kendra K. Grob
Date: September 15, 2025

U21870-MNSC-CE-0561
Page **1** of **1**

Question:

10. Refer to Witness Grob's testimony, pg. 17 and 18, "Savings Plan costs are projected to increase using merit salary rate type increase of 3.2% for 2024 through the 12 months ending April 30, 2027." However, in Exhibit A-97 (KKG-1), pg.2, line 3, the factors applied to arrive at projected "Merit & Inflation" costs are the inflation factors of 2.1%, 2.4%, and 2.4% for 2025, 2026, and 2027, respectively. Please clarify the discrepancy and confirm which factor is correct.

Response:

Exhibit A-97 (KKG-1), page 2, columns b to h, show what the increase would be for applying inflation rates amounts projected out on 2024 actuals for Savings Plan (401k) and column i includes adjustments for change in electric/gas splits, capitalizations, and merit 3.2% adjustment to inflation amounts. Full calculations can be found on WP-KKG-1.

Witness: Kendra K. Grob
Date: September 15, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of O&M Expenses Projected Using Inflation
Add Description
($000)

Case No.: U-2xxxx
Exhibit No.: A-___ (xxx-xx)
Page: 2 of __
Witness: NAME
Date: DATE

Line No.	Description	(a)	(b) Actual 12 Mos Ending 12/31/2019	(b) Actual 12 Mos Ending 12/31/2020	(b) Actual 12 Mos Ending 12/31/2021	(b) Actual 12 Mos Ending 12/31/2022	(b) Actual 12 Mos Ending 12/31/2023	(b) Actual 12 Mos Ending 12/31/2024	(c) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2024	(d) Merit & Inflation 12 Mos Ending 12/31/2025	(e) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2025	(f) Merit & Inflation 12 Mos Ending 12/31/2026	(g) Base O&M for Merit & Inflation 12 Mos Ending 12/31/2026	(h) Merit & Inflation 4 Mos Ending 4/30/2027	(i) Other Adjustments	(j) Projected O&M 12 Mos Ending 4/30/2027
										(c) * Inflation Rate		(e) * Inflation Rate		(g) * Inflation Rate		(b) + (d) + (f) + (h) + (i)
1	Billing & Payment		19,474	16,221	17,126	18,212	15,671	10,176	10,176	-	11,294	-	11,424	-	1,329	11,505
	Labor		3,124	2,409	2,876	2,640	2,489	2,494	2,494	-	2,768	-	2,799	-	163	2,657
	Material		629	510	579	761	882	685	685	-	760	-	769	-	99	784
	Contractor		8,188	7,642	8,425	9,299	6,927	1,365	1,365	-	1,515	-	1,532	-	251	1,616
	Non-Labor Overhead		2,044	-	-	-	-	-	-	-	-	-	-	-	-	-
	Non-Labor Other		5,490	5,659	5,246	5,513	5,372	5,632	5,632	-	6,251	-	6,323	-	815	6,448
2	Customer Interactions		26,509	25,326	28,389	25,769	24,071	20,951	20,951	-	22,635	-	23,004	-	2,503	23,454
	Labor		17,650	17,608	18,761	18,115	17,444	15,605	15,605	-	16,860	-	17,134	-	1,608	17,213
	Material		208	68	81	30	41	69	69	-	74	-	76	-	15	83
	Contractor		7,096	6,345	7,575	6,616	5,601	4,579	4,579	-	4,947	-	5,028	-	508	5,087
	Non-Labor Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Non-Labor Other		1,554	1,305	1,972	1,009	984	698	698	-	754	-	766	-	372	1,070
3	Total CXCO O&M Expenses		45,983	41,547	45,515	43,982	39,741	31,127	31,127	-	33,930	-	34,428	-	3,832	34,959
	Labor		20,774	20,017	21,636	20,755	19,933	18,099	18,099	-	19,627	-	19,934	-	1,772	19,870
	Material		837	578	660	790	923	754	754	-	835	-	845	-	114	868
	Contractor		15,284	13,987	16,000	15,915	12,528	5,944	5,944	-	6,462	-	6,560	-	759	6,703
	Non-Labor Overhead		2,044	-	-	-	0	-	-	-	-	-	-	-	-	-
	Non-Labor Other		7,044	6,965	7,219	6,522	6,356	6,330	6,330	-	7,005	-	7,089	-	1,187	7,517

U21870-SA-CE-113
Requested By: Shannon M. Rueckert (SMR-1 - 4)
Respondent: Patrick D. Daly
Date of Response: 7/18/2025
Page **1** of **1**

Question:

Inflation
4. Please provide a list of all exhibits that use inflation to project O&M expenses.

Response:

- **Projected Corporate Services O&M Expense** - Exhibit A-91 (MJF-2)

- **Projected Information Technology Operations O&M Expense** - Exhibit A-17 (SHB-1), page 2. As noted in the direct testimony of Company witness Stacy H. Baker (page 26, lines 29-30 and page 27, lines 1-6), labor is the only categorical spend projection that includes an increase based on the inflation rate. Inflation is not used to project any other categorical spending projections for IT Operations O&M expense.

- **Projected Benefits O&M Expenses** – Exhibit A-97 (KKG-1), page 2 – line 6, "Other Benefits" only.

- **Projected Electric Distribution O&M Expenses** – Exhibit A-128 (MPK-18). Refer to the direct testimony of Company witness Michael P. Kelly, page 124, lines 6 through 22, and page 125, lines 1 through 3 for further details. Projected Service Restoration expenses (a component of overall Electric Distribution O&M expenses included within the exhibit referenced above), were projected using 2024 historical expenses and applying inflation. Refer to the direct testimony of Company Witness Andrew R. Snider, page 20 lines 1 through 25 for further details.

- **Projected O&M Expenses Facilities and Shared Services** – Exhibit A-101 (QAG-2), page 2. Labor for the real estate department is the only categorical spend projection that includes an increase based on the inflation rate.

U21870-SA-CE-114
Requested By: Shannon M. Rueckert (SMR-1 - 5)
Respondent: Patrick D. Daly
Date of Response: 7/18/2025
Page **1** of **1**

Question:

Inflation
5. Please provide a separate list of all expenses and their exhibit number that show inflation as if it's being used to project an expense, but do not actually use it in the projection. Example: Pension Plan A&B on A-97 KKG-1.

Response:

- **Projected Customer Experience & Operations Expenses** - Exhibit A-53 (JRB-2), page 4. Refer to the direct testimony of Company witness Jessica R. Byrom, page 4, lines 1 through 16 for further details.

- **Projected Demand Response O&M Expenses** - Exhibit A-95 (AMG-2), page 2. Refer to the direct testimony of Company witness Alex M. Gast, page 3, lines 16 through 26, and page 4, lines 1 through 5 for further details.

- **Projected Generation O&M Expenses** – Exhibit A-43 (RTB-4), page 2. Refer to the direct testimony of Company witness Richard T. Blumenstock, page 105, lines 11 through 15 for further details.

- **Projected Benefits O&M Expenses** – Exhibit A-97 (KKG-1), page 2. The following line items show inflation, but the corresponding calculation is not used in the projection of test year expense included within the instant case.

    - Line 1 – Pension Plans A/B
    - Line 2 – Defined Company Contribution Plan
    - Line 3 – 401k Employee Savings Plan
    - Line 4 – Active Health Care/Life Insurance/LTD – only Life Insurance and LTD use the inflation rate. Active Health Care utilizes the healthcare trend rate.
    - Line 5 – Retiree Health Care and Life Insurance
    - Lines 7 through 10 – Pension & OPEB Deferrals and related amortization expenses

- **Projected Electric Distribution O&M Expenses** – Exhibit A-128 (MPK-18). Refer to the direct testimony of Company witness Michael P. Kelly, page 124, lines 6 through 22, and page 125, lines 1 through 3 for further details. However, projected Service Restoration expenses (a component of overall Electric Distribution O&M expenses included within the exhibit referenced above), were projected using 2024 historical expenses and applying inflation. Refer to the direct testimony of Company Witness Andrew R. Snider, page 20 lines 1 through 25 for further details.

CUB-25. Labor Costs Adjustments; WP Bunch Inflation and Productivity Adjustments
p. 1/2

Schedule: C-5.1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Inflation and Merit Increases Included in Operation and Maintenance Expenses
For the Projected 12-Month Period Ending April 30, 2027
($000)

Case No.: U-21870
Exhibit No.: A-13 (PDD-42)
Schedule: C-5.1
Page: 1 of 1
Witness: PDDaly
Date: June 2025

	(a)	(b)	(c)	(i)	(j)	(k)	(p)	(q)		
					Source: labor breakouts from Exhibits in column (b)		Source: non-labor breakouts from Exhibits in column (b)			
Line No.	Description	Source	Historical 12 Months Ended 12/31/2024	Projected 12 Months Ended 4/30/2027	Actual labor; 12 Months Ended 12/31/2024	Projected labor; 12 Months Ended 4/30/2027	Actual non-labor; 12 Months Ended 12/31/2024	Projected non-labor; 12 Months Ended 4/30/2027	Check 12/31/2024	Check 4/30/2027
				(c) + (h)						
1	Electric Division - Electric & Common	Exhibit No.: A-128 (MPK-18)	246,620	300,994	140,584	173,473	106,036	127,521	0	0
2	Forestry	Exhibit No.: A-175 (SES-6)	110,225	186,684	3,262	5,583	106,962	181,101	-	-
3	Generation	Exhibit No.: A-43 (RTB-4)	128,438	103,732	74,738	60,362	53,700	43,371	-	(0)
4	Operations Support	Exhibit No.: A-102 (QAG-3)	14,564	13,600	3,903	4,181	10,661	9,418	-	-
5	Information Technology Operations	Exhibit No.: A-17 (SHB-1)	42,127	55,297	9,279	10,792	32,848	44,505	-	-
6	Information Technology Investments	Exhibit No.: A-19 (SHB-3)	7,835	24,789	2,127	7,667	5,707	17,122	-	-
7	Information Technology - Security Operations	Exhibit No.: A-17 (SHB-1)	9,277	11,362	3,841	4,628	5,435	6,734	-	-
8	Information Technology - Security Investments	Exhibit No.: A-19 (SHB-3)	702	1,513	300	1,019	402	495	-	-
9	Customer Interactions	Exhibit No.: A-53 (JRB-2)	20,951	23,532	15,605	17,213	5,346	6,240	-	78
10	Billing & Payment	Exhibit No.: A-53 (JRB-2)	10,176	11,427	2,494	2,657	7,682	8,848	-	(78)
11	Demand Response	Exhibit No.: A-95 (AMG-2)	31,240	34,630	7,122	6,761	24,118	27,870	-	-
12	Pension Plans A/B	Exhibit No.: A-97 (KKG-1)	(51,785)	(45,156)	(51,785)	(45,156)	-	-	-	-
13	Defined Company Contribution Plan	Exhibit No.: A-97 (KKG-1)	14,774	16,507	14,774	16,507	-	-	-	-
14	401(k) Employees' Savings Plan	Exhibit No.: A-97 (KKG-1)	11,396	12,731	11,396	12,731	-	-	-	(0)
15	Active Health Care/Life Insurance/LTD	Exhibit No.: A-97 (KKG-1)	29,089	33,385	29,089	33,385	-	-	-	-
16	Retiree Health Care and Life Insurance	Exhibit No.: A-97 (KKG-1)	(47,536)	(48,867)	(47,536)	(48,867)	-	-	-	-
17	Other Benefits	Exhibit No.: A-97 (KKG-1)	2,601	2,780	887	948	1,714	1,832	-	0
18	Pension/OPEB Volatility Mechanism Amortizati	Exhibit No.: A-97 (KKG-1)	15,491	(99)	15,491	(99)	-	-	-	(0)
19	Corporate Services	Exhibit No.: A-91 (MJF-2)	37,543	36,968	12,968	11,069	24,575	25,899	(0)	0
20	Uncollectible Expense	N/A	18,074	20,274	-	-	18,074	20,274	(0)	(0)
21	Injuries & Damages	N/A	7,677	5,083	-	-	7,677	5,083	0	0
22	Incentive Compensation	Exhibit No.: A-73 (AMC-3)	2,750	2,211	2,104	2,211	-	-	646	-
23	Job Work Expense	Exhibit No.: A-15 (EMB-3), Schedule E-2	1,278	1,278	-	-	1,278	1,278	(0)	(0)
24	Interest expense on security deposits	WP-PDD-19	298	298	-	-	298	298	(0)	(0)
25	Projected inflation of other O&M expenses	Sum Lines 1 - 24	663,802	804,952	250,644	277,065	412,513	527,888	645	(0)

CUB-25. Labor Costs Adjustments; WP Bunch Inflation and Productivity Adjustments
p. 2/2

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditures Summary
For the Projected 12-Month Period Ending April 30, 2027
($000)

	(a)	(b)	(c)	(g)	(j)	(k)	(p)	(q)		
					Source: labor breakouts from Exhibits in column (b)		Source: non-labor breakouts from Exhibits in column (b)		Check	Check
			Historical							
Line No.	Description	Source	12 Months Ended 12/31/2024	12 Months Ending 4/30/2027	Actual labor; 12 Months Ended 12/31/2024	Projected labor; 12 Months Ended 4/30/2027	Actual non-labor; 12 Months Ended 12/31/2024	Projected non-labor; 12 Months Ended 4/30/2027	12/31/2024	4/30/2027
1	Electric Distribution	Exhibit No.: A-12 (MPK-1), Sch 5.7	920,439	1,529,914	163,901	271,759	756,538	1,258,155	0	-
2	Streetlighting	Exhibit No.: A-12 (DAS-1), Sch 5.9	18,541	16,545	2,648	2,272	15,893	14,273	(0)	-
3	Generation	Exhibit No.: A-12 (RTB-3), Sch 5.2	145,252	188,638	2,219		143,032	188,638	-	-
4	Information Technology	Exhibit No.: A-12 (SHB-4), Sch 5.1	39,979	66,983	5,367	11,102	34,612	55,882	0	(0)
5	Security	Exhibit No.: A-12 (SHB-4), Sch 5.1	4,044	10,736	274	1,129	3,769	9,607	0	-
6	Electric Vehicles	Exhibit No.: A-12 (JAM-1), Sch 5.8	1,431	171	217	26	1,214	145	0	(0)
7	Operations Support	Exhibit No.: A-12 (QAG-1), Sch 5.6	21,298	28,041	1,071	1,539	20,227	26,502	0	-
8	Fleet Services	Exhibit No.: A-12 (QAG-2), Sch 5.6	16,628	67,947	-	-	16,628	67,947	-	-
9	Corporate	Exhibit No.: A-12 (MJF-6), Sch 5.4	1,010	1,064	73	77	937	987	-	-
10	Customer Experience & Operations	Exhibit No.: A-12 (JRB-1), Sch 5.3	1,245	1,870	-	-	1,245	1,870	(0)	-
11	Demand Response	Exhibit No.: A-12 (AMG-1), Sch 5.5	5,156	1,555	-	-	5,156	1,555	0	-
12	Total capital expenditures		1,175,023	1,913,464	175,770	287,904	999,252	1,625,561	1	(1)

Notes

CUB-26 Proposed LVD Pole Replacement surge

Schedule: B-5

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capital Expenditures Summary
For the Projected 12-Month Period Ending April 30, 2027
($000)

(a)	(b)	(c)	(d)	(e)	(n)	(o)	(p)	(q)	(r)	(s)
					Total costs and adjustments					
		Historical			Bridge period projections and adjustments		Test-year projections and adjustments			
Description	**Source**	**12 Months Ended 12/31/2024**	**16 Months Ending 4/30/2026**	**12 Months Ending 4/30/2027**	**CUB projected bridge-year target = (h) + (i) + (j) + (l) + (m) + (n); 16 months ended 4/30/2026**	**Company proposal = (f); 16 Months Ended 4/30/2026**	**CUB projected test-year target = (p) + (k) + (o); 12 months ended 4/30/2027**	**Company proposal = (g) 12 Months Ended 4/30/2027**	**Test-year disallowance based on PAI = (w) - (x); 12 months ended 4/30/2027**	**CUB proposed securitization $s for surge expenditures; 12-months ended 4/30/2027**
Pole replacements PAI baseline estimate	Direct testimony of Jennifer M. Partlan, p. 69, Fig. 35	N/A	29,711	127,500		29,711	22,638 Rounded to 25,000	127,500		102,500 (127,500 - 25,000)

SYSTEM AVERAGE INTERRUPTION DURATION INDEX - SAIDI

Estimated Societal Benefits of Customer Reliability

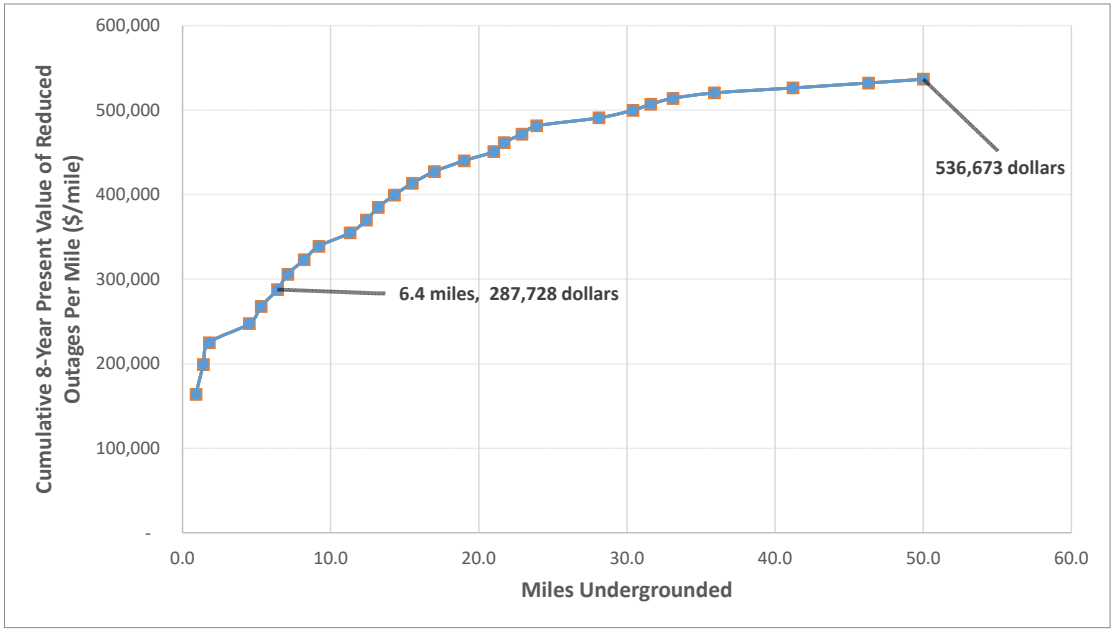
Line No.	Description [1]	Year	Customers [2]	Cost of Interruption [3]	COI Std Deviation [3]	SAIDI [4]		Cost/(Benefit) to Society [5]			MNSC Calculations Cost/(Benefit) Share		
						Status Quo	Roadmap	Min	Average	Max	Min	Average	Max
			(000)	($ per min)	($ per min)	(min / cust)	(min / cust)	($000)	($000)	($000)	%	%	%
1	Residential	2025	1,667.9	$ 0.04	$ 0.05	171	162	$ -	$ (667)	$ (1,400)	0.0%	1.9%	2.3%
2	Small C&I	2025	229.7	14.79	9.81	171	162	(10,919)	(32,448)	(53,976)	89.6%	90.4%	90.5%
3	Medium / Large C&I	2025	1.2	235.10	127.67	171	162	(1,270)	(2,780)	(4,289)	10.4%	7.7%	7.2%
4	Residential	2026	1,677.7	$ 0.04	$ 0.05	171	153	$ -	$ (1,326)	$ (2,782)	0.0%	1.9%	2.4%
5	Small C&I	2026	230.0	15.11	10.03	171	153	(21,605)	(64,202)	(106,799)	89.6%	90.4%	90.5%
6	Medium / Large C&I	2026	1.2	240.28	130.47	171	153	(2,510)	(5,493)	(8,476)	10.4%	7.7%	7.2%
7	Residential	2027	1,686.9	$ 0.04	$ 0.05	171	145	$ -	$ (1,919)	$ (4,028)	0.0%	1.9%	2.4%
8	Small C&I	2027	230.3	15.45	10.25	171	145	(31,145)	(92,549)	(153,954)	89.6%	90.4%	90.5%
9	Medium / Large C&I	2027	1.2	245.56	133.34	171	145	(3,614)	(7,909)	(12,204)	10.4%	7.7%	7.2%
10	Residential	2028	1,695.8	$ 0.04	$ 0.05	171	137	$ -	$ (2,579)	$ (5,413)	0.0%	1.9%	2.4%
11	Small C&I	2028	230.5	15.79	10.47	171	137	(41,677)	(123,847)	(206,016)	89.6%	90.4%	90.5%
12	Medium / Large C&I	2028	1.2	250.96	136.28	171	137	(4,832)	(10,574)	(16,315)	10.4%	7.7%	7.2%
13	Residential	2029	1,703.3	$ 0.05	$ 0.05	171	128	$ -	$ (3,360)	$ (7,052)	0.0%	1.9%	2.4%
14	Small C&I	2029	230.7	16.13	10.70	171	128	(54,098)	(160,757)	(267,415)	89.6%	90.4%	90.5%
15	Medium / Large C&I	2029	1.2	256.49	139.28	171	128	(6,267)	(13,714)	(21,161)	10.4%	7.7%	7.2%
16	Residential	2030	1,708.8	$ 0.05	$ 0.05	171	119	$ -	$ (4,186)	$ (8,785)	0.0%	1.9%	2.4%
17	Small C&I	2030	230.8	16.49	10.94	171	119	(67,224)	(199,762)	(332,299)	89.6%	90.4%	90.5%
18	Medium / Large C&I	2030	1.2	262.13	142.34	171	119	(7,783)	(17,030)	(26,278)	10.4%	7.7%	7.2%
19	Residential	2031	1,712.4	$ 0.05	$ 0.05	171	116	$ -	$ (4,517)	$ (9,480)	0.0%	1.9%	2.4%
20	Small C&I	2031	231.0	16.85	11.18	171	116	(72,422)	(215,206)	(357,990)	89.6%	90.4%	90.5%
21	Medium / Large C&I	2031	1.2	267.90	145.47	171	116	(8,380)	(18,338)	(28,296)	10.4%	7.7%	7.1%
22	Residential	2032	1,713.8	$ 0.05	$ 0.05	171	115	$ -	$ (4,697)	$ (9,856)	0.0%	1.9%	2.4%
23	Small C&I	2032	231.0	17.22	11.43	171	115	(75,258)	(223,635)	(372,012)	89.6%	90.4%	90.5%
24	Medium / Large C&I	2032	1.2	273.79	148.67	171	115	(8,706)	(19,051)	(29,396)	10.4%	7.7%	7.1%
25	Residential	Terminal Value						$ -	$ (92,592)	$ (194,313)	0.0%	1.9%	2.4%
26	Small C&I	Terminal Value						(1,483,680)	(4,408,851)	(7,334,022)	89.6%	90.4%	90.5%
27	Medium / Large C&I	Terminal Value						(171,636)	(375,583)	(579,531)	10.4%	7.7%	7.1%
28	Total							$ (2,073,030)	$ (6,107,573)	$ (10,153,537)			

LVD Trimming Costs Projections						
Year	O&M Full-Circuit Clearing Miles	O&M Subprogram Clearing Miles	O&M Subprogram Spray Miles	O&M Expense ($M)	Capital Clearing Miles	Capital (Contractor) Costs ($M)
2020	3,679	294	238	$ 46.10	258	$ 5.67
2021	4,647	238	395	$ 75.83	252	$ 6.07
2022	5,653	247	488	$ 91.02	221	$ 6.71
2023	5,758	244	443	$ 97.79	168	$ 5.59
2024	5,400	244	421	$ 99.49	258	$ 9.69
2025	6,108	244	413	$ 113.20	325	$ 14.01
2026	7,891	199	405	$ 152.97	325	$ 14.29
2027	10,885	149	454	$ 201.75	325	$ 14.57
2028	12,814	137	501	$ 226.28	325	$ 14.87
2029	13,588	75	491	$ 230.43	325	$ 15.16
2030	14,837	75	508	$ 236.81	325	$ 15.47

2025 - 2030 O&M Total ($M): $ 1,161.44

Line No.	Project	Test Spending ($000s)	Miles	Outage Mins Avoided	8-Year PVRR ($)	8-year PV ($)	PV Net of PVRR ($)
1	BASS LAKE/KISTLER/168	440	1.1	49,426	397,767	16,709	(381,058)
2	BLUE STAR/PIER COVE/622	480	1.2	35,686	433,927	12,064	(421,863)
3	BUTTERFIELD/LINDEN/60	480	1.2	25,080	433,927	8,479	(425,449)
4	CONCORD/SWAINS LAKE/581	400	1.0	28,866	361,606	9,759	(351,848)
5	DEAN ROAD/HARTLAND/951	800	2.0	75,471	723,212	25,514	(697,698)
6	ELEVENTH STREET/BASELINE/268	1,120	2.8	53,410	1,012,497	18,056	(994,441)
7	HALLS LAKE/HALLS LAKE/173	920	2.3	61,463	831,694	20,778	(810,916)
8	LAKE LEANN/LAKE LEANN/282	400	1.0	47,318	361,606	15,996	(345,610)
9	MERSON/MERSON/412	800	2.0	64,148	723,212	21,686	(701,526)
10	PECK ROAD/M-91/473	840	2.1	98,091	759,373	33,161	(726,212)
11	PENINSULA/MAPLETON/124	440	1.1	55,599	397,767	18,796	(378,971)
12	SPRUCE ROAD/EAST BAY/693	200	0.5	51,908	180,803	17,548	(163,255)
13	SPRUCE ROAD/EAST BAY/868	280	0.7	37,643	253,124	12,726	(240,399)
14	YORKVILLE/HIGHLAND PARK/182	440	1.1	47,581	397,767	16,085	(381,681)
15	BALCOM/BANKERS/736	600	1.5	30,819	542,409	10,419	(531,990)
16	BLACKMAN/SANDSTONE/404	1,080	2.7	181,206	976,336	61,259	(915,077)
17	KOLASSA/MATTESON/187	320	0.8	47,956	289,285	16,212	(273,073)
18	TRUFANT/GOWEN/847	440	1.1	64,962	397,767	21,961	(375,806)
19	CASCO/HAWKHEAD/516	280	0.7	22,005	253,124	7,439	(245,685)
20	HANOVER/PULASKI/532	1,680	4.2	117,839	1,518,746	39,837	(1,478,909)
21	LAKE LEANN/LAKE LEANN/159	480	1.2	49,381	433,927	16,694	(417,233)
22	WHITTEMORE/SAND LAKE/28	360	0.9	436,554	325,445	147,582	(177,863)
23	ALGER/SKIDWAY/606	600	1.5	61,365	542,409	20,745	(521,664)
24	ALGER/SKIDWAY/819	320	0.8	35,483	289,285	11,995	(277,290)
25	BRICKER/STOREY ROAD/228	2,040	5.1	86,953	1,844,191	29,396	(1,814,795)
26	HARVARD LAKE/HARVARD LAKE/986	2,120	5.3	92,753	1,916,512	31,356	(1,885,156)
27	SHERMAN/SHERMAN/304	1,480	3.7	50,822	1,337,942	17,181	(1,320,761)
28	BROOKLYN/BROOKLYN/811	160	0.4	30,448	144,642	10,293	(134,349)
					18,080,304	**689,727**	**(17,390,577)**

Line No.	Miles	8-Year Present Value/Mile		Cumulative Miles	Cumulative Benefit/Mile
22	0.9	163,981		0.9	163,981
12	0.5	35,096		1.4	199,077
28	0.4	25,733		1.8	224,810
16	2.7	22,689		4.5	247,499
17	0.8	20,265		5.3	267,764
18	1.1	19,965		6.4	287,728
13	0.7	18,180		7.1	305,908
11	1.1	17,087		8.2	322,995
8	1.0	15,996		9.2	338,992
10	2.1	15,791		11.3	354,782
1	1.1	15,190		12.4	369,973
24	0.8	14,994		13.2	384,967
14	1.1	14,623		14.3	399,590
21	1.2	13,912		15.5	413,501
23	1.5	13,830		17.0	427,331
5	2.0	12,757		19.0	440,088
9	2.0	10,843		21.0	450,931
19	0.7	10,627		21.7	461,559
2	1.2	10,053		22.9	471,612
4	1.0	9,759		23.9	481,371
20	4.2	9,485		28.1	490,856
7	2.3	9,034		30.4	499,890
3	1.2	7,066		31.6	506,955
15	1.5	6,946		33.1	513,901
6	2.8	6,449		35.9	520,350
26	5.3	5,916		41.2	526,266
25	5.1	5,764		46.3	532,030
27	3.7	4,644		50.0	536,673



STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	Case No. U-21870

PROOF OF SERVICE

On the date below, an electronic copy of **Official Exhibit List and Public Exhibits of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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Date: November 11, 2025

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	Case No. U-21870

CONFIDENTIAL
PROOF OF SERVICE

On the date below, an electronic copy of **Confidential Official Exhibits (MEC-6C, MEC-11C, MEC-14C, MEC-29C, and MEC-35C) of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan** was served on the following:

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