TROPOSPHERE LEGAL

August 8, 2025

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

Via E-File

RE: MPSC Case No. U-21859

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Public Official Exhibits and Exhibit List of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan; and
- Proof of Service.
- Please note that MEC-20C is confidential and will be filed under seal.

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: 2025.08.08 11:28:27 -04'00'

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21859

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of **CONSUMERS ENERGY COMPANY** for Ex Parte Approval of Certain Amendments to Rate GPD.	Case No. U-21859

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

Exh #	**Description**
MEC-1	Resume of Douglas B. Jester
MEC-2	Discovery Response U21859-AG-CE-0014 + Att
MEC-3	Discovery Response U21859-MNSC-CE-0034
MEC-4	Discovery Response U21859-MNSC-CE-0078
MEC-5	Resume of Caroline Palmer
MEC-6	Discovery Response U21859-MNSC-CE-0023 Supp. 2
MEC-7	Discovery Response U21859-AG-CE-0015 Supp. 2
MEC-8	Discovery Response U21859-DCC-CE-0052
MEC-9	Discovery Response U21859-MNSC-CE-0126
MEC-10	Discovery Response U21859-MNSC-CE-0032
MEC-11	Discovery Response U21859-MNSC-CE-0021
MEC-12	Discovery Response U21859-MNSC-CE-0025
MEC-13	Discovery Response U21859-MNSC-CE-0037
MEC-14	Discovery Response U21859-MNSC-CE-0076

MEC-15	Discovery Response U21859-MNSC-CE-0026
MEC-16	Discovery Response U21859-MNSC-CE-0075
MEC-17	Discovery Response U21859-DCC-CE-0007
MEC-18	Discovery Response U21859-MNSC-CE-0082
MEC-19	Discovery Response U21859-MNSC-CE-0033 Supp 3
MEC-20C	U21859-MNSC-CE-0033 Supp. CONF. Expanded- Input4 Load Data & TY Sales and Rate Summary
MEC-21	Discovery Response U21859-MNSC-CE-0123
MEC-22	Discovery Response U21859-MNSC-CE-0034
MEC-23	Case No. U-20697, Jan. 15, 2022, Contribution in Aid of Construction Workgroup Report, p.9, 15.
MEC-24	LRTP Tranche 1 Detailed Business Case
MEC-25	*Reserved*
MEC-26	Discovery Response U21859-MNSC-CE-0132 & Attachment
MEC-27	Discovery Response U21859-MNSC-CE-0133 & Attachment
MEC-28	Discovery Response U21859-MNSC-CE-0134
MEC-29	*Reserved*
MEC-30	Discovery Response U21859-MNSC-CE-0136
MEC-31	Discovery Response U21859-MNSC-CE-0137
MEC-32	*Reserved*
MEC-33	Discovery Response U21859-MNSC-CE-0019 + 0019 attachment
MEC-34	*Reserved*
MEC-35	*Reserved*
MEC-36	*Reserved*
MEC-37	Consumers Exhibit A-6 from U-21816
MEC-38	Discovery Response U21859-MNSC-STAFF-1a, b, c, d, e, f,

MEC-39	Discovery Response U21859-MNSC-STAFF-2a, b, c
MEC-40	Discovery Response U21859-MNSC-STAFF-3a, b, c, d
MEC-41	Discovery Response U21859-MNSC-STAFF-4a, 4b
MEC-42	*Reserved*
MEC-43	Staff Initial Comments for Docket 2024-09-27
MEC-44	Discovery Response MNSC-DCC-3.1a, 3.1b, 3.1c, 3.1e, 3.1f, 3.1g
MEC-45	*Reserved*
MEC-46	CMS-Energy-2Q25-Earnings-Release-Combined-Final
MEC-47	CMS-Energy-Second-Quarter-2025-Results-Outlook
MEC-48	Discovery Response U21859-MNSC-DCC-3.3

Troposphere Legal, PLC
Counsel for MNSC

Date: August 8, 2025

By: 
Digitally signed by Christopher M. Bzdok
Date: 2025.08.08 11:28:47 -04'00'

Christopher M. Bzdok (P53094)
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4000

Douglas B. Jester

Personal Information

Contact Information:
220 MAC Avenue, Suite 218
East Lansing, MI 48823
517-337-7527
djester@5lakesenergy.com

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 – present.

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

State of Michigan UP Energy Task Force, 2019-present, 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

Question:

3. Please provide any exemplar contract language (including entire exemplar contracts if they exist) the company plans to use to address the following terms for data center customers:

a. Project proposal fee;

b. Minimum contract term and "ramp up period;"

c. Minimum billing demand;

d. Allowance for reduction in contract capacity;

e. Actions Consumers may take if customer usage exceeds contract capacity;

f. Financial security measures;

g. Exit fees; and

h. Compliance with MCL 205.54ee(10)(e)(ix).

Response:

The Company has prepared the attached draft contract for Rate GPD with the data center provision.

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

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

DATA CENTER PROVISION

CONTRACT FOR ELECTRIC SERVICE
PART I

Parties to Contract	
Company Consumers Energy Company a Michigan Corporation One Energy Plaza Jackson, MI 49201-2357	**Customer**
Customer Facility	
Service Location Name	**Service Characteristics**
Service Location	**Billing Address**
Service Address City	**Customer Account Number** To be assigned at permanent meter set
Service Address County	**Meter Numbers** To be assigned at permanent meter set
Maximum Demand: **On-Peak Billing Demand:** **Monthly Minimum Charge**: Customer Charge, MPSC-approved surcharges and Minimum Billing Demand charge. **Substation Ownership Credit**: Y ☐ or N ☐ **Interruptible Service Provision**: Y ☐ or N ☐	**Term**: 15 Years, beginning on Effective Date.
Additional Pages of Agreement	
The Large General Service Primary Demand Rate GPD – Data Center Provision Contract for Electric Service includes this Part I and the attached Part II (Terms and Conditions, including Exhibits), which is incorporated herein by reference and expressly made a part hereof, together being this "Agreement."	
Execution of Agreement	
Company and Customer hereby enter into this Agreement, as evidenced by the signatures of their authorized representatives below. The Effective Date for service under this Agreement to begin is [_]	

CONSUMERS ENERGY COMPANY	[CUSTOMER]
Garrick J. Rochow President and Chief Executive Officer Consumers Energy Company Date: _____	[Name] [Title] [Company] Date: _____

TERMS AND CONDITIONS

PART II

1. This Agreement is made under Company's Large General Service Primary Demand Rate GPD ("Rate GPD") a copy of which is attached hereto as Exhibit A and made a part hereof. The Agreement is subject to the applicable rates and other tariff provisions approved by the Michigan Public Service Commission ("MPSC"), which may be changed from time to time.

2. The Customer acknowledges and agrees that, as of the Effective Date of this Agreement: (i) the Customer will be a full service electric customer which will take service at the Company's Primary Voltage levels; (ii) in order to receive electric service from the Company, Customer has agreed to a minimum Term of 15 years for this Agreement; and (iii) the Customer will meet a monthly Minimum Billing Demand for the Term this Agreement, which is defined as eighty percent (80%) of the On Peak Billing Demand specified in section 2(a) of this Agreement and eighty percent (80%) of the Maximum Demand specified in section 2(a) of the Agreement. The Customer further acknowledges and agrees to the following requirements:

   (a) On Peak Billing Demand and Maximum Demand Requirements are set based on the ramp up schedule below:

Effective Date	On Peak Billing Demand Requirement	Maximum Demand Requirement
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW

   (b) In the event that the Customer's monthly On Peak Billing Demand and/or Maximum Demand is below the Minimum Billing Demand, the Customer shall pay the Company an amount equal to the difference between the actual service taken and the Minimum Billing Demand, calculated at the applicable rates.

   (c) In the event Customer's On Peak Billing Demand or Maximum Demand exceeds the amounts specified in Part I of this Agreement, the Company may require amendment to Part I of this Agreement to reflect the actual service taken. The Minimum Billing Demand will be adjusted upward to reflect any increases to the On Peak Billing Demand or Maximum Demand specified in Part I of this Agreement.

   (d) Customer Exit Fee: In the event Customer ceases taking power supply service from the

Company at the Customer Facility identified in Part I of this Agreement during the Term of this Agreement, the Company shall be entitled to recover from Customer an Exit Fee. The Exit Fee shall be calculated by multiplying the Minimum Billing Demand by the remaining months left in the Term, based the date on when Customer ceases taking power supply service from the Company. The Company may, at its sole discretion, reduce the Exit Fee if it determines that the loss of the Customer's load will not harm the Company or its other customers.

3. Customer shall provide the Company with financial security or other collateral from the Customer, the suitability of which will be determined by the Company in its sole discretion, in amounts up to the projected cost of providing service to the Customer for the Term of this Agreement, as specified in Exhibit B to this Agreement. This requirement shall not be interpreted to limit the Company's authority to require other financial security requirements from the Customer.

4. Customer shall pay an upfront administrative fee, not to exceed one hundred thousand dollars ($100,000) per project proposal, to cover the costs associated with preparing the proposals. This fee shall be charged directly to the entity requesting the proposal and is non-refundable.

5. The Company agrees to supply, and the Customer agrees to purchase hereunder, all of the electric energy for the operation of the Customer's Facility described in Part I.

6. The electric energy to be supplied hereunder shall be alternating current and shall have the characteristics identified in Part I. Delivery shall be made at one mutually agreeable point upon the Customer's premises. It shall be metered by meters furnished, installed and maintained by the Company. A location for the metering equipment, suitable to the Company, shall be provided by the Customer and adequate protection afforded to avoid damage thereto, tampering or interference with such metering equipment. The Company shall make periodic tests of its meters and keep them within accepted standards of accuracy.

7. The Customer shall pay the applicable charges as provided in the Large General Service Primary Demand Rate GPD, which may be modified time to time by the MPSC, or other applicable rate as approved by the MPSC.

8. It is further agreed that:

   (a) Such service is for the sole use of the Customer and shall not be transmitted elsewhere, or shared or resold, or used as auxiliary or standby as to any other source of power supply, except as may be herein provided.

   (b) The Company reserves the right, at its sole discretion, to allow a one-time adjustment to the Contract Capacity. This adjustment must be mutually agreed upon by both the Company and the Customer and will be documented in an amendment to the existing contract. If the Customer's usage exceeds the Contracted Capacity by 1,000 kW or more, the Company shall have the right to amend the contract to reflect the increased usage. The Customer will be responsible for any additional costs incurred due to this increase in capacity. Should additional capacity be unavailable, the Customer shall be required to reduce its usage to the Contract Capacity. Failing to comply with this

requirement, the Company reserves the right to suspend service.

(c) Such service shall be governed by the Company's Rate Book for Electric Service ("Rate Book") and such future revisions and amendments hereof, supplements thereto, or substitutions therefore as may be filed with and approved by the MPSC during the Term of this Agreement. A copy thereof will be furnished to the Customer upon request.

(d) Except as to the Monthly Minimum Charge payable by the Customer, neither party shall be liable to the other for damages for any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's control, including any curtailment of service by the Company, or order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party hereto; provided, however, that the Company's responsibility for interruptions in service, phase failure or reversal, or variations in the service characteristics shall be as provided in the Company's Rate Book.

(e) This Agreement will become Effective on the date identified in Part I and will extend for a Term as stated in Part I and from month to month thereafter until terminated by mutual consent, or by either party giving the other at least twelve (12) months written notice of its desire to terminate the same at the expiration of any monthly period after the initial Term. Notwithstanding the foregoing, the Company may, in its sole discretion, terminate this Agreement on ninety (90) days' written notice if the MPSC issues an order which disallows or otherwise impairs the Company's cost recovery associated with this Agreement. Notice of termination of this Agreement after the initial Term by the Customer to the Company or vice versa shall be provided in writing.

(f) This Agreement inures to and binds the heirs, administrators, successors and assigns of the respective parties hereto. There are no understandings or agreements between them in relation to electric service at the facility service location stated in Part I except as set forth herein. This Agreement supersedes all previous representations, negotiations, understandings or agreements, either written or oral, between the parties hereto or their representatives pertaining to the subject matter hereof and constitutes the entire agreement of the parties. This Agreement shall not be transferred by the Customer or otherwise alienated without the Company's written consent; any such attempted transfer without the Company's written consent shall be void.

(g) The Customer shall furnish, without cost to the Company, a suitable site on its premises location listed in Part I for the Company's distribution lines, substations, and/or facilities as may be required to provide such service to said premises. If, during the Term hereof, the Customer's use of said premises makes necessary the relocation of said facilities, from the site presently furnished, to another site on said premises, the Company shall relocate the same at the Customer's request, and the Customer shall

reimburse the Company for the cost thereby incurred. The Company, its agents, employees, and authorized contractors shall have full right and authority of ingress and egress at all times on and across said premises of the Customer, for the purpose of constructing, operating, maintaining, replacing, repairing, moving and removing its said facilities. Said right of ingress and egress, however, shall not unreasonably interfere with the Customer's use of said premises.

(h) This Agreement may be executed and delivered in counterparts, including by an electronic transmission thereof, each of which shall be deemed an original. Any document generated by the parties with respect to this Agreement, including this Agreement, may be imaged and stored electronically and introduced as evidence in any proceeding as if original business records. Neither party will object to the admissibility of such images as evidence in any proceeding on account of having been stored electronically.

9. Severability. In the event that any provision or portion of this Agreement shall be determined to be invalid or unenforceable for any reason, the remaining provisions of this Agreement shall be unaffected thereby and shall remain in full force and effect. In the event that the Term, Minimum Billing Demand or Customer Exit Fee provisions of this Agreement are determined to be invalid or unenforceable, the parties will use good faith efforts to promptly amend this Agreement to ensure appropriate cost recovery for the Company if: (i) there is any shortfall in the Customer's usage below the Minimum Billing Demand threshold and (ii) Customer ceases taking power supply service from the Company at the Customer Facility identified in Part I of this Agreement during the Term of the Agreement.

Question:

18. Please identify each type of cost associated with interconnecting a new large load customer of 100 MW or larger. For each type of cost, please identify whether it is directly assigned to the prospective customer load.

Response:

Cost associated with interconnecting a new large load customer of 100 MW or greater includes Transmission and Distribution costs.

Transmission costs could include, but are not limited to, new transmission lines built between the existing transmission facilities and the location of the new load, new transmission switching station(s) at the site of the load or elsewhere, transmission network upgrades such as reconductoring of transmission lines, substation equipment replacement, system protection relaying upgrades, line or substation facilities to increase transmission capacity for the new load addition, and/or line routing and easement acquisition. The transmission costs listed are for interconnection costs of load and do not include additional transmission costs to interconnect new energy resources to serve the load.

Distribution costs could include, but are not limited to, new distribution lines built between existing or new transmission facilities and the new dedicated customer substation, distribution switching station(s), dedicated customer substation(s), line routing and easement acquisition, and/or power factor correction equipment depending on the customer's power factor.

Supply resource costs are not included in these types of costs, as those are associated with serving new load not interconnection costs. Feasibility studies, customer meetings, contract negotiations, etc. are not considered in this response because they could be incurred with or without interconnecting new load.

The Company does not currently direct assign costs to specific customers but rather allocates costs in accordance with the requirements set forth in 2008 PA 286.

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

Question:

13. Please refer to the response to U21859-MNSC-CE-0034.

a. Please identify the specific portion(s) of 2008 PA 286 to which the Company is referring in the Company's statement that it "allocates costs in accordance with the requirements set forth in 2008 PA 286."

b. Are the referenced requirements for allocating new load interconnection costs under 2008 PA 286 implemented in specific tariffs or cost of service methodologies? If so, please identify and produce those tariffs and cost of service methodologies.

c. Explain how the Company's Contribution In Aid of Construction policy interacts with the referenced requirements for allocating new load interconnection costs.

d. The response to U21859-MNSC-CE-0034 lists dedicated customer substation(s) as a potential distribution cost associated with interconnecting a new large load customer of 100 MW or greater. Define "dedicated." Explain why the Company would not directly assign the cost of "dedicated" customer infrastructure to that customer.

Response:

a. The response incorrectly referenced 2008 PA 286 when the reference should have been MCL 460.11(1). MCL 460.11(1) states that "the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class." The Company files and has its COSS reviewed for adherence of this standard and approved by the Commission.

b. The requirements apply to the COSS in its entirety. For a copy of the Company's most recently approved COSS, please see the Company's response to U-21859-DCC-CE-0009.

c. The Company's CIAC policy is outlined in its approved tariff on Sheets 3.0 -4.0. The Company may collect from customers the cost of distribution facilities via a refundable contribution (Customer Advance) or non-refundable contribution (CIAC). CIAC is removed from the plant balance that gets included in the Company's COSS and Customer Advances, which are treated as a deduction to rate base, are currently allocated based on distribution plant in service.

d. Dedicated refers to a substation put in place to serve one customer. See the Company's response to subpart c for an explanation of how the Company recovers those costs from that customer.

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

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, 24-196, 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 Massachusetts 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. 2025. Large Load Tariffs – Current Efforts to Minimize Risk to Consumers. NASUCA Mid-Year Meeting. Columbus, OH.

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

Question:

7. Please refer to the Direct Testimony of Laura M. Connolly, p. 8 lines 9-11 and specify whether any of the over 15 GW of prospective data center load would qualify as an enterprise data center under Public Act 207 of 2024, and if so, how much of the prospective data center load would qualify. Please also specify:

a. Whether the aggregate capital investment in any one of the potential data center facilities would be $250,000,000.00 or greater, and if so, what percentage of the prospective data center load is this true of.

b. Whether any of the prospective data center customers, along with their affiliates, would create and maintain a minimum of 30 new full-time jobs in Michigan with an annual wage that is equal to 150% or more of the prosperity region median wage through December 31, 2050, and if so, what percentage of the prospective data center load is this true of.

c. Whether any of the prospective data center facilities would be located on the property included in a brownfield plan under the brownfield redevelopment financing act or on property that was once an industrial site used primarily as a power plant to generate electricity for sale, and if so, what percentage of the prospective data center load is this true of.

d. For any of the potential data center facilities located on property described in Request 7(c), whether any of the prospective data center customers, along with their affiliates, would create and maintain a minimum of 30 new full-time jobs in Michigan with an annual wage that is equal to 150% or more of the prosperity region median wage through December 31, 2065, and if so, what percentage of the prospective data center load is this true of.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that said request is not relevant to a determination of reasonable modifications to the Company's Rate GPD tariff to allow for certain customer protections. The Company further objects to this request to the extent that it calls for a legal conclusion. Subject to this objection, and without waiving it, Consumers Energy responds as follows:

Qualification as an enterprise data center is determined by the Michigan Strategic Fund. The Company is not a party to that determination.

a. Most potential data center customers have not shared investment figures with the Company. Three requests have indicated capital investments above $250,000,000. U-21859-AG-CE-0015 Supplemental identified 15,849 MW of projects. The three requests totaled 945 MW or 5.96% of the total inquired MW shared investment figures above $250,000,000.
b. This information is not disclosed to the Company.

c. The majority are not considering brownfield sites. One of the requests may qualify as a brownfield but more site information and due diligence would be needed to understand the brownfield status. U-21859-AG-CE-0015 Supplemental identified 15,849 MW of projects. The one potential brownfield site represented 200 MW or 1.26% of the total inquired MW. Consumers Energy does not know if potential data center customers are considering former generation plants.
d. This information is not disclosed to the Company.

Witness: Laura M. Connolly
Date: May 28, 2025

Question:

4. Please provide a list of all requests to serve new data center load the Company has received over the last 12 months, including for each data center:

a. Location of the proposed data center;

b. Requested contract demand;

c. Any contract language for each data center addressing the items described in sub-question 1-3.a-h above (including the entirety of contracts addressing these terms, to the extent they exist);

d. Any determinations the Company has made for financial security measures and any "ramp up period[s]" for such data centers, along with the analyses, studies, and calculations used in making those determinations (including such analyses, studies, and calculations for a data center even if a final determination has not yet been made); and

e. Analyses, studies, and calculations the Company has conducted concerning an assessment of potential stranded asset costs and cost shifting for the data center.

To the extent the Company might typically seek a Protective Order concerning material sought by this question and the other questions in this request, it is welcome to propose a draft of such a Protective Order for consideration.

Response:

a. The following chart sets forth the inquiries for potential service Consumers Energy has received in the last twelve months from potential data center customers. Note that these are inquiries, and do not represent commitments to take service from the Company. Please see attached.

Id	Location	Load (MW)
1	East Central region	300
2	East Central region	400
3	South Central region	1,000
4	East Central region	300
5	Unknown	300
6	East Central region	300
7	Unknown	200
8	Unknown	Unknown
9	Unknown	200
10	Unknown	250
11	Southeasterly region	Unknown
12	East Central region	200
13	East Central region	1,000
14	East Central region	2,100
15	Southwest region	500
16	West region	300
17	Unknown	300
18	Unknown	500
19	Unknown	420
20	East region	100
21	Unknown	300
22	East region	700
23	Unknown	1,000

Id	Location	Load (MW)
24	East Central region	300
25	Unknown	Unknown
26	Unknown	500
27	Unknown	Unknown
28	Unknown	60
29	South Central region	100
30	Unknown	70
31	Southwest region	Unknown
32	East region	500
33	Unknown	Unknown
34	South Central region	75
35	Southwest region	50
36	Southwest region	219
37	Unknown	Unknown
38	Unknown	1,200
39	Unknown	300
40	Southwest region	4
41	Unknown	300
42	Unknown	Unknown
43	Unknown	Unknown
44	Southeasterly region	100
45	Unknown	500
46	Southeasterly region	10

Id	Location	Load (MW)
47	East Central region	300
48	East Central region	1,000
49	Unknown	1,000
50	Unknown	500
51	Unknown	Unknown
52	Unknown	500
53	Unknown	500
54	Unknown	600
55	Southeasterly region	Unknown
56	Unknown	Unknown
57	Unknown	145
58	Unknown	1,000
59	East region	100
60	East Central region	250
61	Unknown	500
62	Southeasterly region	500
63	Unknown	200
64	Unknown	900
65	East Central region	Unknown
66	Northeast region	100
67	Unknown	300

b. See response to a.

c. See response to U21859-AG-CE-0014

d. Financial security has not been evaluated for all inquiries. The Company has evaluated the financial security of one customer based on their publicly available credit rating. No financial calculations or analysis was performed. As stated in U-21859-AG-CE-0064, the Company did not perform analysis using spreadsheets or formulas, as it reviewed publicly available credit and

financial data regarding the customer. The Company does not make any determination or perform any analysis on ramp up periods but rather works with each potential customer to determine if the Company can meet their expected ramp up period.

e. The Company does not perform such a study for each inquiry. The Company has not performed any stranded costs studies. The Company has not evaluated the impact of cost shifting for any specific customer inquiry as the Company has not entered into any new contracts for data center customers to date.

Witness: Laura M. Connolly
Date: May 28, 2025

Question:

21859-DCC-CE-0020. Please refer to the Company's response to DCC-5 and DCC-6 (U21859-DCC-CE-0005 and 0006). Why did Consumers engage with the Transmission Owner to evaluate 2.65 GW of large load additions (as opposed to any other amount)?

Response:

The Company engaged with the Transmission Owner on 2.65 GW of large load additions based on advanced discussions with economic development and data center projects that are considered to be more probable prospects.

Witness: Laura M. Connolly
Date: May 13, 2025

Question:

7. Provide Consumers' annual peak demand in each of the past 10 years.

Response:

Year	Month	MW	Day	Hour
2015	July	7231	28	16
2016	August	7635	11	15
2017	July	7057	19	16
2018	July	7568	5	16
2019	July	7476	19	16
2020	July	7675	9	14
2021	August	7370	24	16
2022	June	7528	21	18
2023	September	7518	5	16
2024	August	7472	26	16

Source:
MPSC P-521 Page 401

Witness: Laura M. Connolly
Date: June 10, 2025

Question:

16. Please explain Consumers' basis for proposing a load threshold of 100 MW (as opposed to a lower threshold) for the proposed Rate GPD data center provisions.

Response:

The tariff provisions proposed are intended to address the large hyper scale data centers and these tend to be around 100 MW or greater.

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

Question:

5. Please refer to the Direct Testimony of Laura M. Connolly, p. 5 lines 10-12.

a. How many large-scale data centers would need to come online before Consumers would develop a rate specific to data centers?

b. What duration of load data from large-scale data centers would Consumers need in order to develop a rate specific to data centers?

c. Would it be feasible for Consumers to develop a rate specific to data centers before large-scale data centers come online? If not, identify and explain each reason why not.

Response:

a. The Company has not developed a target number of large-scale data center customers that would need to come online before developing a rate.

b. The Company typically uses three years of actual, historic load data in order to develop a load shape that can be used to develop cost allocations.

c. The Company could develop a rate without any actual load data, however that would require making assumptions about the prospective customer load profile to assign costs in the COSS.

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

Question:

9. Please refer to Consumers' Application, para. 8, along with the testimony of Laura M. Connolly p. 6 lines 4-8, and explain how a 15-year minimum contract term reflects the term of power supply resources that include self-build resources with a 30 year or greater depreciation schedule and 15- to 25-year PPAs.

Response:

The 15-year minimum contract term was proposed to strike a balance between the life of the assets that may be procured to serve these customers, the life of the infrastructure the data center will put into place, while remaining competitive with other utility data center tariffs.

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

Question:

21. Refer to Consumers' Application at para. 9, along with the Connolly Testimony at p. 6 lines 9-16.

a. Explain the basis for setting the Minimum Billing Demand at 80% of the Contract Capacity, rather than some other percentage. Produce any analysis, workpapers, or other documentation regarding the 80% Minimum Billing Demand.

b. Did Consumers assess the potential impact of a minimum billing demand other than 80%? If yes, provide the results of that assessment, along with any analysis, workpapers, or other documentation.

Response:

a. The Company set the Minimum Billing Demand at 80% based on benchmarking against other utility data center tariffs.

b. No.

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

Question:

11. Please refer to Exhibit A-1 (LMC-1) page 3 (tariff Sheet No. D-67.10), stating "The Company may reduce the Exit Fee if it determines, in its sole discretion, that the loss of Customer's load will not harm the Company or its other customers." How will the Company determine that the loss of a data center customer's load will not harm the Company or its other customers?

Response:

The Company will review the requested load termination and determine if there is a new customer that could be served by the resources which were used to serve the exiting customer's load.

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

Question:

10. Please refer to Consumers' Application, para. 10 and explain how Consumers would determine whether a requested reduction in contract capacity would create a stranded asset or otherwise shift costs to the Company or its other customers.

Response:

The Company will review the requested load reduction and determine if there is another customer that could be served by that load.

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

Question:

10. Please refer to Consumers' Application, paragraph 13.

a. Did the Company consider applying an exit fee during the ramp up period? (For example, a graduated fee that increases at specified stages of the ramp-up period). If so, please explain in detail the basis for not including such a proposal in the proposed tariff revisions. If not, please explain why not.

b. If the data center customer does not originally take service at the distribution level, would the Company consider it eligible for the exit fee if it stops taking generation electric service?

c. Will the exit fee also include Rate GPD's System Access Charge and any applicable non-consumption based surcharges?

Response:

a. The Company believes the exit fee should apply during the ramp up period and will support clarifying that in the tariff language.

b. If the customer is taking service on the data center provision, they would be responsible for the exit fee requirements regardless of how they take service.

c. No.

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

Question:

DCC-7. Please provide a description of the generation investment the Company believes would be required to serve approximately 15 GW of new peak load.

a. If the Company has evaluated the generation investment necessary to accommodate a different level of peak load increase, identify the specific load increase evaluated and provide a description of the generation investment the Company believes would be required to serve that level of peak load increase.

Response:

The Company has not evaluated generation investment required for 15 GW of additional peak load.

a. The Company has considered load growth scenarios and required generation supply for up to approximately 2 GW of new peak load. Generation investment requirements have not been identified for the load growth, in isolation. Instead, the Company adds load growth scenarios to existing or projected peak load requirements for the entirety of its service territory. Determination of generation investment required for projected peak load is done within the integrated resource plan process. Incremental generation investment would be identified in the Company's next IRP.

Witness: Laura M. Connolly
Date: April 16, 2025

Question:

17. Please identify each type of cost associated with building and interconnecting new energy resources to serve the new load associated with a new large load customer of 100 MW or larger.

a. For each type of cost, please identify if there is any circumstance under which the cost is directly assigned to the prospective customer.

b. Please describe and identify the range of total new energy resources costs for a prospective new customer load of 100 MW or larger.

Response:

a. The Company is not proposing to direct assign any costs to data centers but rather allocate them according to the requirements of MCL 460.11(1), which is how it treats other customers.

b. These costs are currently unknown and the range of costs depends on the specific mix of new resources required to serve the customer. The incremental (new) customer load will be included within the portfolio optimizations included in the IRP process.

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

Question:

17. Please provide all analyses conducted by or at the direction of Consumers to analyze the potential impact(s) of data centers on:
a. Consumers' revenue;
b. Consumers' net income or profit;
c. Consumers' cost of service study results, including cost allocation to customer classes;
d. Cost-shifting or cross-subsidization among customer classes; and
e. Residential rate or bill impacts.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request to the extent it calls for privileged attorney client information created in anticipation of litigation. Consumers Energy further objects to the request to the extent that any evaluation contains unaggregated customer data that is subject to the Company's data privacy tariff.

a. The Company has not performed this analysis.

b. The Company has not performed this analysis.

c. Consumers Energy is unable to provide this analysis as it was developed at the request of counsel in anticipation of this litigation and contains unaggregated customer data. The Company can provide the attached cost of service model which allows the intervenor to input their own cost and load assumptions to calculate the impacts of increased data center load. This is provided subject to the entry of a confidentiality agreement with the Company or a protective order due to the LTILRR data. Load data assumptions for data centers can be entered into the highlighted yellow section of the Input 4 Load Data and TY Sales tab. Any cost assumption changes can be entered in the appropriate category in the Input 1 tab. These changes will then flow through the model and you can view impacts on the EAD-6 Part 1 tab. The Company will walk intervening parties through this model at their request and will provide a later response with a hypothetical, discussing where the assumptions are coming from, that is representative as to how the Company is looking at new data center customers. The model has been updated to provide analysis based on a hypothetical 500 MW, 100% load factor customer. The costs have been updated based on a 500 MW PPA using publicly available data from NREL. The load shape was estimated assuming a 500 MW using the same energy for all hours of the year.

d. See response to c.

e. See response to c.

Witness: Laura M. Connolly
Date: June 6, 2025

CONFIDENTIAL ATTACHMENT NOT INCLUDED IN PUBLIC VERSION OF EXHIBIT MEC-20C

Question:

4. Refer to U21859-MNSC-CE-0035, estimating a range of $46.5M to $96M total costs for interconnection facilities for a new 100 MW load.

a. Please provide an explanation of the basis for the Company's estimated range of $46.5M to $96M total costs for interconnection facilities for a new 100 MW load.

b. In live, unlocked Excel file format with all links and formula intact, provide all workpapers and calculations underlying the estimated range.

c. To the extent that the estimated range includes both transmission and distribution costs, please specify separate ranges for transmission and distribution costs.

Response:

a. For the Distribution asset estimates, the Company took 5 typical projects (this excluded projects that had unique aspects that would falsely inflate the average of a typical project) and determined the average cost per transformer. The Company then took this average and calculated the number of transformers required at each voltage to serve 100 MWs. The rounded result became the average high and low range for distribution cost.

   Estimates for transmission facilities required to interconnect a new 100 MW load utilized transmission cost estimates provided by the impacted Transmission Owner(s) for recent ~100 MW projects in the Company's service territory. 2 projects fell within range of the 100 MW size requested. A third project, representing a smaller load addition, was also included in the cluster to present a potential low-end transmission interconnection facility requirement assuming existing transmission infrastructure could reliably handle 100 MW of additional load.

b. See attached file.

c. The estimated range for distribution upgrades excluding outliers used was $28.0 Million - $34.0 Million. The estimated range for Transmission upgrades used was $18.5 Million - $62.0 Million. For a total average range of $46.5 Million - $96 Million.

   As noted in the response to U21859-MNSC-CE-0035, interconnection facilities for a 100 MW load can vary greatly based on location and network upgrades required to adequately interconnect the load while maintaining system reliability.

Witness: Laura M. Connolly
Date: June 10, 2025

Question:

18. Please identify each type of cost associated with interconnecting a new large load customer of 100 MW or larger. For each type of cost, please identify whether it is directly assigned to the prospective customer load.

Response:

Cost associated with interconnecting a new large load customer of 100 MW or greater includes Transmission and Distribution costs.

Transmission costs could include, but are not limited to, new transmission lines built between the existing transmission facilities and the location of the new load, new transmission switching station(s) at the site of the load or elsewhere, transmission network upgrades such as reconductoring of transmission lines, substation equipment replacement, system protection relaying upgrades, line or substation facilities to increase transmission capacity for the new load addition, and/or line routing and easement acquisition. The transmission costs listed are for interconnection costs of load and do not include additional transmission costs to interconnect new energy resources to serve the load.

Distribution costs could include, but are not limited to, new distribution lines built between existing or new transmission facilities and the new dedicated customer substation, distribution switching station(s), dedicated customer substation(s), line routing and easement acquisition, and/or power factor correction equipment depending on the customer's power factor.

Supply resource costs are not included in these types of costs, as those are associated with serving new load not interconnection costs. Feasibility studies, customer meetings, contract negotiations, etc. are not considered in this response because they could be incurred with or without interconnecting new load.

The Company does not currently direct assign costs to specific customers but rather allocates costs in accordance with the requirements set forth in 2008 PA 286.

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

Michigan Public Service Commission

Contribution in Aid of Construction Workgroup Report

MPSC Case No. U-20697

January 15, 2022

Dan Scripps, Chair
Tremaine Phillips, Commissioner
Katherine Peretick, Commissioner

LARA
LICENSING AND REGULATORY AFFAIRS

Contents

Executive Summary

On December 17, 2020 the Michigan Public Service Commission (MPSC) directed MPSC Staff (Staff) to convene a workgroup to address the Contribution in Aid of Construction (CIAC) policy of Consumers Energy Company (Consumers).[1] This direction was in response to the MEC Coalition's[2] analysis of and recommendations for CIAC policies in Consumers' general rate case.[3] According to the MEC Coalition, Consumers' existing CIAC policy predated unbundled ratemaking and created subsidies between customer classes. Rather than require Consumers to implement the MEC Coalition's recommendations in the Company's next rate case, the Commission ordered Staff to "establish a framework for participation and a conference schedule; and, in collaboration with participants, a list of topics, issues, and objectives to be addressed and achieved." Following the conclusion of the workgroup, Staff was required to file a report "detailing its findings and recommendations regarding any recommended changes to the Commission's CIAC policies that can be considered in future rate case." This report will present the CIAC workgroup's activities including a summary of its three conferences, an overview of the discussions held during those conferences, and the joint recommendations of the workgroup.

This report is organized as follows:

1. Introduction to the Commission's recent orders on CIAC policy
2. Overview of the workgroup's meetings
3. Details of MEC Coalition's analysis and proposal for CIAC policies
4. Discussion topics explored by the workgroup and ongoing issues with CIAC policies
5. Recommendations

The key findings of this report are: CIAC policy is a complex issue that directly affects new and existing utility customers, the workgroup was unable to reach consensus on which revenues to use in setting CIAC policy, the workgroup sees benefit in continuing to meet for further discussion on more specific CIAC topics, and CIAC reform should only take place in general rate cases**.** Staff is grateful for the generous participation of all workgroup members.

[1] December 17, 2020 Order in MPSC Case No. U-20697, p 330-331.
[2] The MEC Coalition is made up of the Natural Resources Defense Council, Sierra Club, and Citizens Utility Board.
[3] MPSC Case No. U-20697.

Introduction

CIAC policies are those that require a customer requesting a new connection to an electric distribution utility's system to pay a refundable deposit for a portion of the costs associated with the new connection or line extension. Should other new customers attach to the system extension partially paid for by the original customer's deposit, that original customer will receive a refund as prescribed in the utility's tariff.

Typically, a general service customer requesting a line extension for less than 1,000 kW of load must pay the difference between the cost of the connection and the expected total revenue generated by the customer over a period of time, such as 2 years. Commercial and industrial (C&I) customers over 1,000 kW are afforded an allowance set by a standard table, which varies by the number of full service contract years, including for customers without a full service contract.

A deposit by residential customers is usually required for extensions beyond an initial allowance (e.g., 600 feet) at a flat cost per foot of additional distribution extension. The deposit may be offset by a refund if additional customers attach to the original customer's extension at a later date. The allowances, length of revenue generation offset, price per foot of extension, deposit refund conditions, and special considerations for underground extensions are codified in the utility's CIAC tariff. New customers create new costs for their connection, but they also create new revenue for the utility to offset costs beyond the connection project timeline. These CIAC policies are intended to balance the cost associated with new customer connections between those individual customers and the existing rate base at large, while allowing an affordable way for customers to join the system.

Distribution line extensions requiring CIAC via customer deposits are not to be confused with the service line extension to the customer's building. Service lines begin at the nearest utility pole and terminate at the Customer's meter. Every customer requires a service line whereas a customer may not require a distribution line extension (i.e., zero foot extension) if there is already a utility pole near enough for connection.

Consumers filed a general rate case in February 2020. The MEC Coalition intervened in the case and proposed changes to existing CIAC policy to be included in the utility's following rate case. Consumers recommended that any changes to CIAC policy should be withheld until a future case or proceeding due to the complexity of the issues at stake. The Commission agreed with the administrative law judge's opinion that a workgroup should be convened to discuss such issues but did not agree that updated CIAC tariffs should be included in Consumers' next rate case.

The Commission directed Staff to convene the CIAC workgroup in 2021 to consider updates to CIAC policies. Staff was required to provide notice of the workgroup, create a framework for participation, and create a list of topics, issues, and objectives in collaboration with workgroup participants. This report, as ordered by the Commission, provides the input of the parties and recommendations of the workgroup's effort for use in future rate cases.

Prior to the Consumers case, for which the CIAC workgroup was created, the MEC Coalition made a substantially similar proposal in DTE Electric Company's (DTE's) general rate case. The Commission's final order in the DTE case was issued on May 8, 2020[4] and differed from its later order in the Consumers case by directing DTE in its next case to: "(1) provide supplementary, substantial, and specific support of the current CIAC model, (2) demonstrate that the current CIAC model is cost-of-service based, (3) provide evidence specifically showing how the overall revenues from new customer connections help offset other customer costs, and (4) provide details regarding how new customer connections drive upgrades to the system that may benefit other customers."[5] While the Commission ordered a different approach for the two largest electric utilities in the state, Staff invited and received participation by both companies in the CIAC workgroup formed from the Consumers case order.

The MEC Coalition presented analysis which examined the payback periods for new customer attachments and compared those periods between customer class in both the Consumers and DTE cases, assuming that only distribution plant revenues should be considered in the payback period calculation. In both cases the MEC Coalition asserted that residential customers generated additional revenue to offset their line extension costs faster than larger general service customers, implying a subsidy was taking place under existing CIAC policies. To correct for the alleged subsidy, the MEC Coalition proposed to standardize the payback period for line extensions across customer classes. In the DTE case, the Commission found the MEC Coalition's proposal to be unsupported but requested that DTE provide evidence to support its existing CIAC policy. In the Consumers case, the Commission demurred that the issues were complex and required additional study.

Neither utility was required to adjust tariffs or propose new CIAC policy in subsequent cases. However, it is clear that the Commission is interested in further study of CIAC policy issues as evidenced by the request for support in DTE's case and the creation of the workgroup in Consumers' case. This report provides details on the MEC Coalition's analysis and proposal as well as the discussion and findings of the CIAC workgroup for the Commission's consideration in following cases. Because the workgroup was created in response to the MEC Coalition's proposal in the Consumers case this report will focus at times on the particulars of that utility, but the discussion and some recommendations may still apply to DTE and other utilities' CIAC policies.

The analysis and discussion presented in this report does not bind any of the participating parties to a particular CIAC policy recommendation unless expressed otherwise in a formal

[4] The final order in the DTE case was issued between the filing of the Consumers case and the MEC Coalition's similar proposal in the Consumers case.
[5] May 8, 2020 Order in MPSC Case No. U-20561, p 98.

proceeding before the Commission. While the process was instructive for the workgroup members, it should not constrain any future proposals for any reason.

Workgroup Meetings

Staff notified parties to the Consumers case of the formation of the CIAC workgroup and held meetings on August 24, September 21, and October 15, 2021. The Association of Businesses Advocating Tariff Equity (ABATE), Consumers, DTE, the MEC Coalition, and Staff all participated in the workgroup meetings. While the workgroup was created in response to the Commission order in the Consumers case, DTE was invited to and participated in the meetings in anticipation of CIAC issues being addressed in its next rate case.

The first meeting included a presentation by 5 Lakes Energy on behalf of the MEC Coalition to review its CIAC analysis and proposal made in the 2020 Consumers case with an update to the model with data from Consumers current on-going general rate case[6]. Further details of the MEC Coalition's presentation will be addressed in the next section of this report. Staff led an open-ended discussion following the MEC Coalition's presentation and debuted a list of topics, issues, and objectives to the workgroup. As a result of the workgroup's discussion, Consumers agreed to present a review of its CIAC policy at the next meeting. Staff explained its intention for the workgroup's ultimate report to the Commission and the format for future workgroup meetings.

The second meeting consisted of separate presentations by DTE and Consumers regarding each utility's CIAC policy along with examples of how a customer would engage with the utility during the line extension process. The presentations generally supported the utilities' current CIAC policies. Following the presentations, another free-flowing discussion ensued which expanded on issues brought up in the first meeting and from the utilities' presentations.

Staff reserved the third meeting of the workgroup to present its draft report and discuss initial recommendations. The workgroup discussed lingering issues from the previous meetings and narrowed the scope for its recommendations to the Commission. Following the third meeting Staff continued to develop the workgroup's report and recommendations and engaged with stakeholders on the report's contents throughout the early winter of 2021.

MEC Analysis and Proposal

In direct testimony on behalf of the MEC Coalition in the 2020 Consumers general rate case Robert Ozar of 5 Lakes Energy sponsored and discussed the CIAC analysis and proposal that

[6] MPSC Case No. U-20987.

spurred the CIAC workgroup's efforts in 2021.[7] Mr. Ozar reproduced his analysis for the CIAC workgroup using updated data from the current Consumers rate case. His analysis relies on the idea that Consumers' current CIAC policy predates unbundled rate making (i.e., the division of rates between power supply and delivery to accommodate customer choice in energy provider). When the utility was vertically integrated, a customer's total revenue could be assumed to offset all costs associated with being served by the utility's generation, transmission, and distribution systems. For this reason, the CIAC policy for general service customers provides an allowance for three times the customer's expected *total* annual revenue.[8] The MEC Coalition argued that since the advent of unbundled electric service, the actual offset to extension cost made by the customer is to the distribution capital revenue requirement. According to the MEC Coalition, applying an allowance of a new customer's total revenue over three years for what the MEC Coalition argues is only a distribution capital investment thus creates a mismatch. Further, according to the MEC Coalition, only a portion of total distribution revenue can be said to apply to the distribution capital revenue requirement. In other words, they claim that only a portion of a customer's total bill going forward will end up contributing to the new connection to the distribution system.

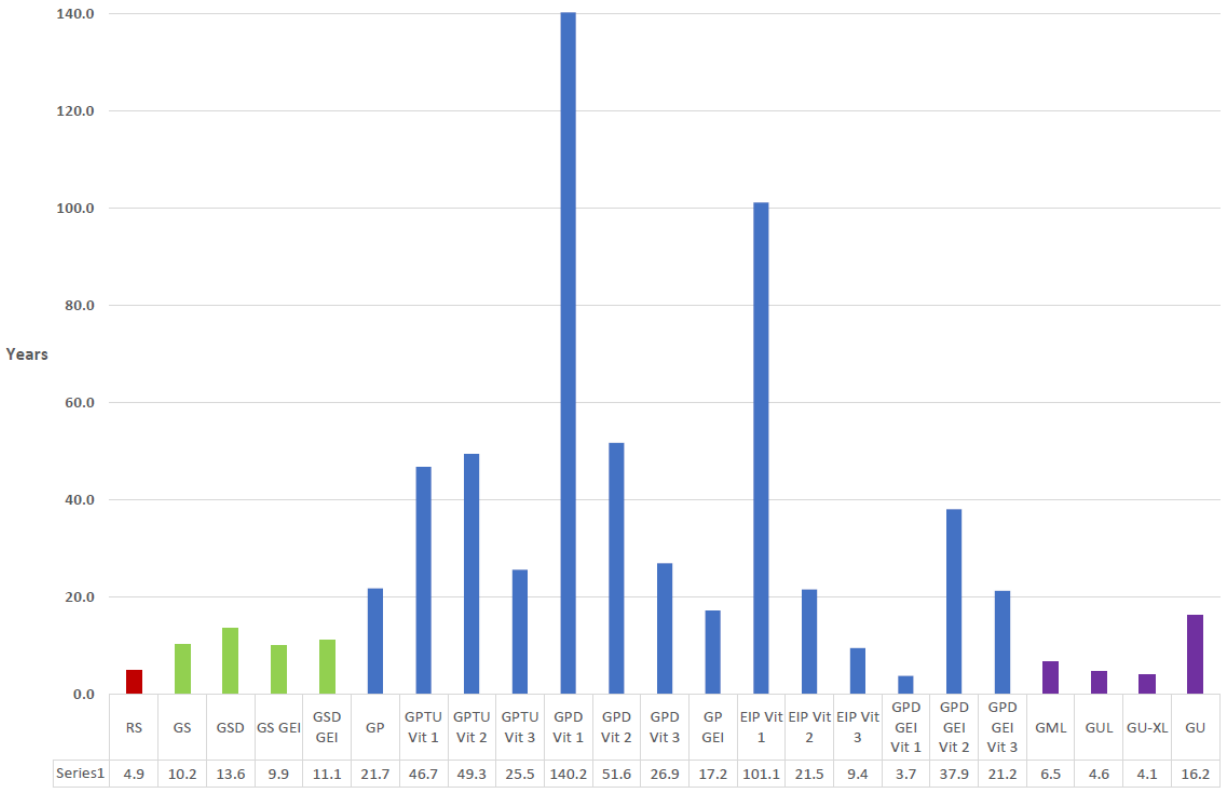
The MEC Coalition opined that the aforementioned balancing act of CIAC policy – between the additional costs a new customer creates versus their continued contribution to the distribution system—no longer holds under Mr. Ozar's analysis. Because only a part of the customer's total revenue over 3 years will pay for the utility's upfront contribution toward the new line extension under their assumption, it thus takes longer for the customer to "pay it off" through base rates than the tariff assumes. Fundamentally, the MEC Coalition argued that it takes much longer for this to occur for a general service customer than it does for a residential customer because the power supply revenues from general service customers are a larger percentage of total revenues. In order to quantify the purported difference in payback periods among customer classes, Mr. Ozar calculated how long it would take a customer in each class to repay the Company's CIAC allowance using only the portion of revenue associated with distribution capital. The CIAC allowances for some rates had to be calculated differently because of the different CIAC policies offered to residential and general service customers (e.g., 600 foot allowance for residential overhead lines versus 3 years of total revenue for general service.) Mr. Ozar found that when applying only the distribution capital portion of customer revenue to the appropriate allowances, it took 4.9 years for an overhead-line-serviced residential customer to pay back their allowance and between 26.9 and 140.2 years for a General Primary Demand (GPD) customer, voltage level 3 and 1 respectively. This is because a relatively smaller portion of GPD customers' overall bills is revenue associated with distribution capital. Based on this analysis, Mr. Ozar concluded that

[7] For an in depth explanation of the MEC Coalition's analysis see Mr. Ozar's testimony in Case U-20697.
[8] The tariff provides adjustments for differences between expected and actual revenues and refunds for additional customers connecting to the new service extension. See Sheet No. C-27.00 in the Consumers rate book for details.

Consumers current CIAC policy creates a subsidy between customer classes, because general service customers are allowed such a long time to achieve parity with the rest of customers contributing to distribution rate base compared to residential customers, who do so much more quickly, since a larger portion of their overall bills is associate with distribution capital costs.

Figure 1

Payback Times for Distribution Systems Additions Under Current CIAC Rule



MEC Coalition Presentation to CIAC Workgroup 9/24/2021

To remedy the alleged disparity among classes, Mr. Ozar calculated a uniform payback period for line extensions by taking the reciprocal of the economic carrying cost of total electric distribution capital investment, or the electric distribution rate base divided by the capital portion of distribution revenue requirement (i.e., total distribution capital divided by total annual revenues associated with paying for that capital). This resulted in a system-wide average of 7.42 years, or the time it takes for distribution revenue alone to pay for distribution capital costs. In order to apply this uniform payback period to each rate schedule individually, Mr. Ozar then multiplied the 7.42 years times the capital-related portion of each distribution rate. This is akin to creating any other type of rate, where required revenue is divided by sales to reach a $/kWh rate, but in this case the required revenue is the capital-related portion of distribution revenue, which is then multiplied by 7.42. Thus, an individual customer would receive an allowance of the newly calculated credit rate times their estimated annual energy usage.

Figure 2

MEC Coalition CIAC Reform-Utility Contribution

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

While the rates differ for every customer type, they are all based on the same 7.42 years Mr. Ozar believes it takes for all customers' collective distribution revenues to pay off distribution capital. Alternatively, a footage allowance could be calculated using the MEC Coalition's proposal by multiplying the per kWh residential allowance by the class average sales per customer then divided by an updated cost-per-foot of line extension (See Appendix A for MEC Coalition's complete presentation.)

Under this scheme, Mr. Ozar calculated that the average residential customer's allowance would be reduced from $4,250 to $3,157, and general service customers would also see a decrease in CIAC allowance. The ultimate beneficiaries would be the existing Consumers customers who, after CIAC reform, would pay less through base rates to cover the cost to extend service to new customers. It may be counterintuitive to see the residential allowance decrease when attempting

to resolve the alleged subsidy between residential and general service customers, however, the reduction in CIAC allowance, under the uniform payback approach is larger for general service customers. That is because the solution also affects the alleged subsidy between existing customers currently paying base rates and the new customers receiving a line extension.

The MEC Coalition's analysis can be affected by a number of assumptions, chiefly, 1) the assumption that only distribution capital-related revenues should be recognized in the analysis, and 2) the cost per foot of residential distribution line extension. The analysis in the Consumers rate case relied on the $3.5 per foot cost for additional line extension beyond the 600 foot allowance for residential customers as the actual cost for distribution investment in line extension. In the workgroup presentation, Mr. Ozar accounted for this assumption by providing a chart showing how different costs per foot of line extensions affects the residential allowance. The greater the cost per foot of extension the less footage would be included in the allowance. The primary cause of reduction in length of residential extension allowance is related to the out-of-date per foot cost in the tariff. As will be discussed, parties disagree on the validity of the assumption that only distribution capital-related revenues should be recognized.

The CIAC policy reform proposed by the MEC Coalition would be included as a table in Consumers' line extension tariff and be updated in general rate case proceedings with newly approved cost data.

Discussion

The MEC Coalition's analysis and proposal spurred a great deal of discussion among the workgroup members. Utility, Staff, MEC, and ABATE experts engaged in debate on the assumptions, outcomes, and merits of the work presented by the MEC Coalition as well as purpose and nature of CIAC policy in general. This section of the report represents the continuation of the analysis of CIAC policy and will provide the Commission with further investigation into the ideas and implications raised by the workgroup. The final section of this report will be the synthesis of that investigation via the workgroup's recommendations.

How much power supply revenue should be included in deposits, or should only distribution capital be used to determine the deposit amount?

Perhaps the most discussed topic of the workgroup meetings was on whether it is appropriate to consider only distribution capital investment and revenues in the MEC Coalition's analysis. On its face, it seems reasonable to conclude that a line extension only affects the cost of the distribution system, since the line extensions are physical infrastructure installed to deliver electricity to the new connections. However, the new load connected to the utility's distribution system still needs to receive power from somewhere. While the new customer necessarily requires more wires to join the system, they are also providing additional revenue for power supply, if they are a full service customer. This incremental revenue may be more difficult to discern. During the workgroup discussion, it was clear that some parties believe that a portion of power supply revenue could be attributed to offsetting the line extension, since the utility receives incremental revenue from supply as well. Like in so many other facets of utility regulation that "some portion" can be difficult to define.

ABATE argued that when considering the policy in the context of whether a customer chooses to locate in the territory or not, the incremental margin of revenues over fixed costs, inclusive of both supply and delivery, will benefit all customers, as it will contribute to virtually any rate base item on which the utility receives a return.

DTE presented its current CIAC policy to the workgroup during the second meeting. The tariff for this policy provides a standard allowance table for customers requesting a line extension with a load greater than 1,000 kW. This table offers different allowances for customers choosing full service contracts and no full service contracts, with full service contract customer allowances varying by the number of years on such contracts. Customers requesting a line extension without a full service contract receive a smaller allowance because they will not produce power supply revenues to offset any marginal increase in power supply cost. This solution neatly addresses the issue about whether total revenue or only distribution revenue should be considered in CIAC policy because it treats the two services differently. Arguments can still be made about how much power supply revenue is reasonably necessary to offset the increase in costs related to the customer's new load. However, it is assumed by some that non-power-supply customers would

not contribute to any marginal power supply costs; so they should not receive an allowance for that missing revenue. In theory, this method could be applied to residential customers as well, because they too can participate in customer choice of power supply. However, practically speaking, distinguishing between full service and choice customers is unhelpful because of the enrollment cap in customer choice. What DTE's CIAC tariff does is explicitly consider that for power supply customers some costs associated with line extension is related to power supply.

The question remains: if power supply revenue should be considered to offset incremental power supply costs for new load, then how much? Consumers' general service CIAC policy lies on one end of the spectrum where total power supply revenue for three years is implicitly assumed fully available to pay for the incremental increase in distribution cost (i.e., the distribution line extension). The MEC Coalition's CIAC reform policy is situated at the opposite end of that spectrum where the utility's contribution toward the line extension is made only through recognition of the customer's future distribution revenue and there is no assumed offset for power supply. This issue begs another question: how much incremental pressure does one customer's newly connected load put on power supply? If the utility has sufficient capacity in its power supply to accommodate the single source of new load, then the pressure (i.e., added cost) is zero. If that single customer's new load happens to be at the margin that requires the utility to expand its power supply, then the pressure, and thus cost, is significant.[9] As is often the case with issues of marginal power supply, the costs can be said to be zero until they aren't. Depending on the specific circumstances of the issue sometimes an analyst will rely on some form of market prices to determine marginal power supply costs or perhaps assume the most common method a utility may use to increase its power supply to meet new load (e.g., 75% of cost of new entry.)

In summary, ABATE, Consumers, and DTE all agreed that power supply revenue should be included in the offset for CIAC for full service customers. MEC advocated for its proposal to only rely on distribution capital-related revenue to determine line extension deposits, as discussed in the third section of this report. DTE made a further distinction that power supply fuel revenues should not be included in full-service revenues for the purpose of CIAC. Staff did not take a position on changes to CIAC policy in either the recent Consumers or DTE cases wherein MEC made its reform proposals and remains skeptical on this specific issue of what revenues to include in line extension deposits. The workgroup did not arrive at a consensus on this topic, but its contemplation led to the other issues discussed herein.

[9] This is the same inter-generational equity issue that has existed for decades for rates in general. Some might ask, "Why should legacy customers have to pay for new facilities (generation or delivery), if they've already paid for facilities sufficient to meet their needs?". But that is not how traditional rate setting works; rates have been set treating customers of all durations the same for decades.

Updating current line extension cost per foot

The actual cost per foot of line extension and how it differs from the tariff was raised several times during workgroup discussion. The Consumers tariff still shows a cost per additional foot of line extension beyond the 600 foot allowance for residential customer of $3.50. In contrast, DTE's residential line extension tariff charges $6.50 per foot beyond 600. Consumers did not contend that $3.50 was the actual current cost per foot for additional overhead distribution line. It was clear that the figure used in the tariff was many years old but Consumers was willing to explore reexamining the excess line extension charge for residential customer deposits. According to Consumers, 25-30% of complaints to the MPSC are about costs being too high for new construction.

To further complicate things it would be difficult to determine an exact per foot cost for line extension that would be applicable to all projects. For example, one line extension project could require more utility poles than another project of equal length. In this case the project with more poles would have a higher cost per foot for the extension. This also begs the question: if actual costs per foot of line extension is higher than the tariff, then should the cost for additional foot of extension be increased or should the allowance for footage be decreased? One could also consider the $3.50 per foot of additional line extension as a "charge" rather than the utility's direct cost being passed through to the customer. Should this be the case then that "charge" would still need to be linked to a cost, or net-cost, in some fashion in order to keep rates cost-based. Upon further investigation, the Commission could determine that the charge per additional foot of line extension should be made up of the combination of actual cost of the physical infrastructure being built less some amount representative of the benefit of additional load. Taking it one step further, should a line extension allowance and/or charge consider whether the new customer is a distributed generation customer? This is all to say that while it may be tempting to include an actual cost estimate per foot for extending service, there are other ways to incorporate the actual costs into CIAC allowances and charges. Updating the cost per foot in the tariff could also create a higher barrier for new customers to attach to the distribution system. Discouraging new load on the system through more onerous CIAC policy will negatively impact existing customers as well, assuming the new load contributes revenues above variable costs and thereby provides a contribution to fixed costs, enjoyed by all other customers. If one considers the role of the new customer after they have provided incremental revenues sufficient to cover their CIAC credit amount, then all future revenue from the customer can be said to help offset the rates of all other customers. When allocating costs and designing rates, the more customers and load available over which to spread those costs relieves the burden on the individual customer. Any utility would prefer to sell more of its product to more customers, and in the long-run existing customers benefit from load growth, so long as the cost of that growth is lower than the long-run benefits.

It could be beneficial to match actual costs of line extension more closely with CIAC charges over the standard allowance, but it must be weighed against the benefit to existing

customers. As shown in Mr. Ozar's analysis the cost of the line extension could have a direct impact on the allowance for residential customers.

Whether or not the Commission approves a change to the residential line extension cost per foot in the utilities' tariffs, the allowance for C&I customers need not be changed. There is no specific cost per foot of line extension printed in the tariff for these customers. Instead, the allowance is dependent on the customer's revenue, with contractual assurance that the revenue target is actually met. For example, for C&I customers with load greater than 1,000 kW, the customer's CIAC allowance is set based on a standard allowance table, as shown below from DTE's rate book[10]:

Figure 3

DTE Electric CIAC Standard Allowance Table

Rate Schedule	Full Service Contract Term, Years					No Full Service Contract
	1	2	3	4	5	
D11, D10, D3	$120 / kW	$230 / kW	$330 / kW	$430 / kW	$520/ kW	$95 / kW
D6.2	$120 / kW	$230 / kW	$335 / kW	$435 / kW	$525/ kW	$95 / kW
D8, R1.1, R1.2, D3.3	$90 / kW	$170/ kW	$245 / kW	$320 / kW	$385/ kW	$95 / kW
R10	$40 / kW	$75 / kW	$110/ kW	$145 / kW	$175 / kW	$95 / kW
D4	$245 / kW	$480 / kW	$695 / kW	$895 kW	$1,085 / kW	$95 / kW

Section C6.2(4)(a), Sheet No. C-30.00, based on anticipated average maximum demand

For these larger customer extensions current CIAC policy fixes the allowance based on full service contract year terms and charges the customer with the total cost of the extension beyond that allowance. This is contrasted by residential CIAC policy which sets prices and the allowance based on footage alone. For residential customer footage is a proxy for total line extension cost for rather than passing the actual cost through to the customer less an allowance like for C&I customers. The shortcoming of CIAC policy for residential compared to C&I customers is that the actual cost (i.e., total cost less allowance) of the line extension is not specifically borne by the customer. Therefore, updating the per foot line extension cost for residential customers may bring customer classes closer to parity in CIAC policy.

[10] Consumers has a similar table in section C1.4 (Sheet No. C-4.00) of its rate book, but allowances are calculated on anticipated energy rather than demand.

Determining footage allowance

Similar to the discussion on updating the cost for additional line extension footage in the tariff is how to set the free footage allowance. Both Consumers and DTE offer residential customers the first 600 feet of line extension free of charge. It came to light through discussion with the workgroup that this figure is not based on any specific calculation, but that most new individual customers fall below that threshold. In theory, if the typical customer requires 600 or fewer feet of line extension, and they only require about 4 years of distribution revenue to repay that allowance, that customer will quickly join the pool of customers contributing revenues above incremental costs. If another customer requires a longer line extension, then it stands that they will take longer for them to provide revenues above incremental costs. More data would be necessary to determine how much more costly it is to extend service to customer beyond 600 feet, and whether that cost increases linearly.

Determining the appropriate footage allowance could also run afoul of a basic tenet of electric rate design: calculating rates based on the cost of serving the *average* customer. If 600 feet were found to be the amount of line extension under which most new customers fell, then it ignores the amount of distribution line needed to serve the average customer. If the average customer only required a 200 foot extension, then at what length beyond that average is it appropriate to begin charging customers a deposit? Again, more analysis is necessary to confirm or evaluate this question, and particularly analysis showing whether or not the cost of a line extension increases linearly, or by some more complex function. This complex function could include the problem of how many utility poles are necessary for any given distance of line extension. For example, the cost per foot may be flat up until the next pole is required, at which point the flat cost ratchets up.

Customer deposits for line extensions can also be viewed as a transfer of risk from the utility to the customer requesting an attachment. A customer requiring a short extension of the distribution system is relatively low-risk to add compared to a similar customer much further away. If it is riskier to extend the system beyond 600 feet because costs increase beyond that distance or there are greater hazards in construction, then requiring a deposit would offset that risk.

During the second workgroup meeting, Staff posited a potential solution to updating costs and line extension footage allowances. Using a minimum system study, an analyst could determine the minimum amount of distribution line necessary to reach any customer on a utility's system. [That analysis differs from the traditional "minimum system study," which considers the zero load cost of connecting customers to the system.] That minimum would then be the standard allowance in footage or cost, with all excess cost to be recovered through the customer's deposit. The problem with this hypothesis is that the length of distribution system needed to attach the nearest customer could be zero. Such an analysis would require a number of assumptions, which would themselves inspire further debate. Another method suggested by Staff would be to calculate system-wide average or customer class average of distribution line footage per

customer. That average could then be used as the CIAC allowance, with all excess extension costs to be included in the deposit.

While Consumers believes that the currently approved residential footage allowance of 600 feet is ideal, because it represents the average line extension necessary for residential customers (not including zero foot extensions) and adjusting the residential footage allowance could significantly impact the cost to customers for attachment to Consumers' system, the company is still open to exploring the topic further. Likewise, DTE is open to exploring the topic further.

Like with any theoretical cost allocation question, a trade off must be considered between burdening the existing customer, the new customer, the average customer, the outlier customer, and the vulnerable customer. Determining the charge for additional line extension and the standard allowance for the extension must also consider this trade off.

Effects of changing CIAC policy on revenue requirement

Beyond its effect on individual customers requesting a line extension, CIAC policy also affects the utility's revenue requirement. Changing CIAC policy such that it requires larger customer deposits, as the MEC Coalition's proposal would, reduces the utility's capital spending and thus its revenue requirement. If the new customer or load continues to be a going concern that contributes to the utility's revenue longer than the time it takes to recoup the initial outlay for line extension, then both the utility's shareholders and customers come out ahead. Shareholders will enjoy the return on increased capital spending and the customer base will enjoy another member to which costs can be spread. One potential pitfall of CIAC policy occurs when the customer at the end of the new line extension discontinues their service before their revenue can fully offset the extension costs. Requiring a customer deposit alleviates this concern somewhat.

It would also be difficult to determine if and when a line extension becomes no longer used and useful because at any time a new customer could come along and take advantage of the line extension. Again, this issue requires a delicate balancing act on the part of CIAC policy: how does the Commission balance the need of new connections to the system with those already connected? Extending distribution infrastructure without attachable customers would be a waste for current ratepayers, but the argument can be made that *eventually* there will be more customers to attach. Though the reasonableness of that argument must be evaluated carefully.

Further, the impact on revenue requirement from changes in CIAC policy for one customer class may affect all classes. In electric cost of service studies customer deposits for line extension are part of working capital and allocated to customers on revenue. For example, if CIAC policy reform arises from this report that would increase residential customer deposits then the

corresponding revenue requirement reduction would be spread to all customers and not just the residential class.

The impact of CIAC policy on a utility's revenue requirement can be substantial. According to its workgroup presentation Consumers spends about $14M to connect new residential customers per year. Overall spending on new business, including line extension, can make up a significant portion of any utility's rate case request, and adjusting something as innocuous as the CIAC policy can eventually flow through rate case models and have a material impact on rates. This fact supports the workgroup's recommendation that the Commission consider implementing changes to CIAC policy only in general rate case proceedings, where the effects of those changes can be observed directly. A standalone proceeding or workgroup such as the one creating this report can provide insight to future Commission decisions, but any actual change in CIAC policy or tariffs should occur as part of a comprehensive rate proceeding.

Extraordinary facilities exemption

In the meeting, ABATE indicated that large customers for whom significant investments are made to connect them, are subject to minimum charges that help ensure that they provide revenues sufficient to cover the costs. Although they may exist to help ensure payment for extraordinary distribution costs, such minimum charges are based on demand charges that include power supply costs. ABATE suggests that this linkage between distribution connection costs and supply revenues further supports the position that both supply and delivery revenues should be considered, rather than just delivery revenues, as proposed by the MEC Coalition.

ABATE also notes the distinction between customers who pay minimum charges and those who do not in terms of reduced risk of stranded investment costs associated with distribution connections. Thus, the existence of minimum charges has an interplay with connection costs that should be recognized in the analysis, rather than just a simple payback period analysis that does not capture the risk difference.

Consumers supports ABATE's views on the extraordinary facilities exemption and recommends that if the Commission approves an alteration of residential line extension cost per foot that the allowance for C&I customers remains unchanged.

Line extension as an economic development tool

Line extension policies can be an important tool in the economic development package. Great care should be taken in considering policies that will detrimentally impact the state and local communities' ability to attract large customers.

Equity issues

The specifics of the MEC Coalition's proposal may suffer from equity issues. As described in the previous section of this report, the proposal would create a table of $/kWh allowance rates to be applied to the customer's projected energy use. For example, using data from the current Consumers electric case the MEC's Coalition's proposal results in an allowance credit rate of $0.40710 per kWh for residential customers. If a customer had an estimated monthly usage of 1,000 kWh, or 12,000 kWh annually, the customer would receive an allowance of $4,885 toward their line extension and be required to pay the excess as a refundable deposit. The flat per kWh allowance credit means that a customer using half the energy of the 1,000 kWh per month customer would also receive half as much in line extension allowance, or $2,442. A customer with a larger house or an electric vehicle would therefore be awarded a larger allowance than a customer with on-site solar generation or extensive energy efficiency investments. Any action that would drive down the customers annual energy usage would directly reduce their CIAC allowance. It seems unfair for a low-income or senior customer with relatively low annual energy consumption, for example, to receive a smaller CIAC allowance, however the higher energy use customer would still contribute more of their new revenue to offset the line extension investment. That being the case, if both the low-use and high-use customers remain in service for long enough to fully pay in for their line extension, then both can be said to be successfully entered into paying base rates; but the initial outlay for the customers remains different. A rural customer may be more likely to require a longer line extension than their urban counterpart even if they both generate the same revenue for the utility. While the urban and rural customer would have the same CIAC allowance they would face very different costs to connect to the distribution system.

Another equity issue discussed by the workgroup pertains to larger general service customers on demand rates. The MEC Coalition's proposal creates per kWh based allowance rates. The bulk of the revenue generated from Consumers general primary demand rates comes from, as the name implies, demand charges. Because the MEC Coalition's proposal relies on distribution revenues it should have noted that Rate GPD's distribution charges are only demand or customer charges and not energy billed rates. The mismatch between the MEC Coalition's proposal and existing rates for demand-billed customers can and should be easily fixable by simply using demand as the billing determinant rather than energy to calculate a demand-based allowance rate. This is already the case in DTE's tariff for large customer line extension allowances, which are all per kW credits.

Finally, any CIAC policy, existing or proposed, should consider equity in access to electric service. If electricity is requisite to living a healthy and safe life in modern society, then all who desire the service should be equally allowed reasonable and fair access.

Recommendations

Based on the discussion throughout the three workgroup meetings and condensed and presented in this report, the workgroup offers several recommendations to the Commission for considering CIAC policy. These recommendations are made on behalf of the workgroup as a whole and not just certain individual parties therein. While some recommendations may seem overall generalized it is because they come from a general group of stakeholders. That is also to say that recommendations made by any of the authors of this report in future cases or proceedings before the Commission are likely to be at odds and will require continued thoughtful consideration by the Commission.

Further consider updating the cost per foot of line extension presented in tariffs.

The workgroup discussed the origin of existing cost per foot of additional line extension beyond the 600 foot allowance and agreed that whatever data were used to create it are likely obsolete. Updating the tariff with an actual, approved cost-based charge for line extension would give confidence to customers that their refundable deposit is rooted in the actual investment made by the utility. Per the discussion in the previous section of this report, the footage allowance for line extension may also need to be readjusted in light of a different additional footage charge.

Only change CIAC policy in general rate cases and not standalone proceedings.

As explained in the discussion section of this report CIAC policy can be very influential on revenue requirement, rates, and on individual customers engaging with their utility. Line extension tariffs can even expand beyond the scope of the Commission's authority to set rates, because a CIAC policy that is too lacking or too generous to a customer can influence whether or not a new house is built, or a new business launched. The effect of CIAC policy can be observed as it flows through the financial model, cost of service study, and finally the rate design when made in a rate case. Because of the wide reaching effects of CIAC policy on the rate making process and potentially on economic development, any adjustment proposed to and approved by the Commission should only be done in the context of a general rate case proceeding.

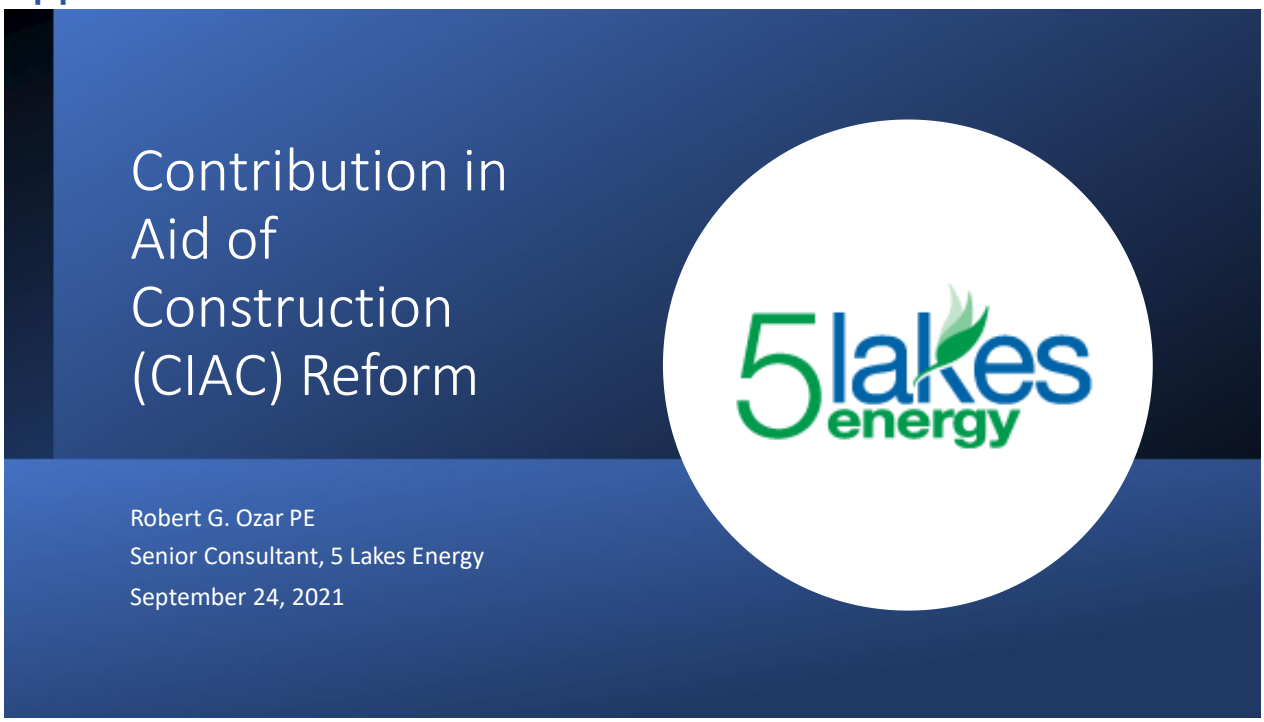
Continue CIAC workgroup meetings to further develop known issues and gather data for further analysis. Stakeholders may use the discussion and data to make proposals in future cases.

Outside of a contested rate proceeding stakeholders would be able to further discuss CIAC policy and generate novel approaches to creating equitable and fair line extension allowances. The Commission may require utilities to answer audit request from the workgroup members to gather the data needed to support alternative CIAC policy approaches. Future CIAC workgroup meetings could narrow the scope of analysis to residential line extension CIAC policy, for example, or to how CIAC policy impacts economic development.

Conclusion

The CIAC Workgroup members worked prodigiously through the fall of 2021 to hold open and honest discussions on CIAC policy reform. These discussions furthered the group's understanding of CIAC policy as well as allowed workgroup members the opportunity to share their unique and diverse perspectives on the issues at hand. Continuing the conversation into 2022 will allow the workgroup to focus deliberations and encourage a robust record on CIAC in future rate case proceedings. The workgroup is pleased to present this report to the Commission for consideration.

Appendix

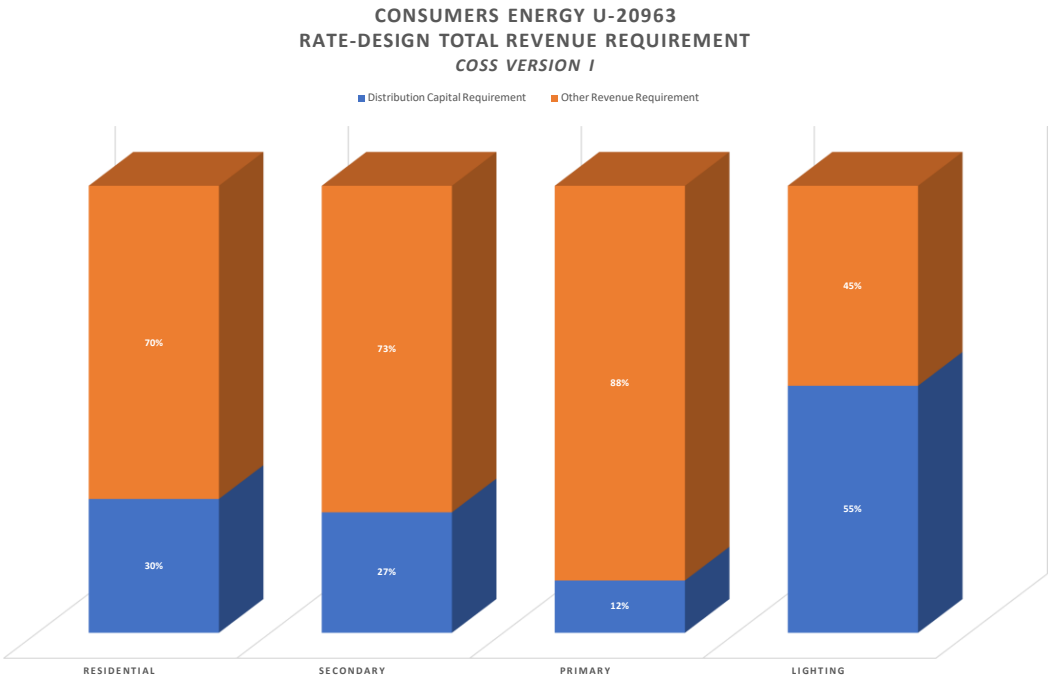


Current Electric CIAC Policies are Inappropriate

Current CIAC methodology predates unbundled rate making

Utility contribution to line extensions is based on both distribution and production revenues

Only the capital related portion of distribution revenues is relevant to determining utility contributions, as line extensions are classified as distribution plant



Calculation of Payback Period for Company Contribution (Under Existing Rules)

- $Payback\ (yrs) = \frac{\$\ Contribution\ by\ Company}{Estimated\ Capital\ Related\ Distribution\ Revenue/yr}$

- $Payback\ (yrs) = \frac{(Distribution+Powersupply)\left(\frac{\$}{kWh}\right)xC\left(\frac{kWh}{Yr}\right)x3Yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right]x\left[\frac{Distribution\ Revenue}{Total\ Revenue}\right]x\ (Distribution+Powersupply)\left(\frac{\$}{kWh}\right)xC\left(\frac{kWh}{Yr}\right)}$

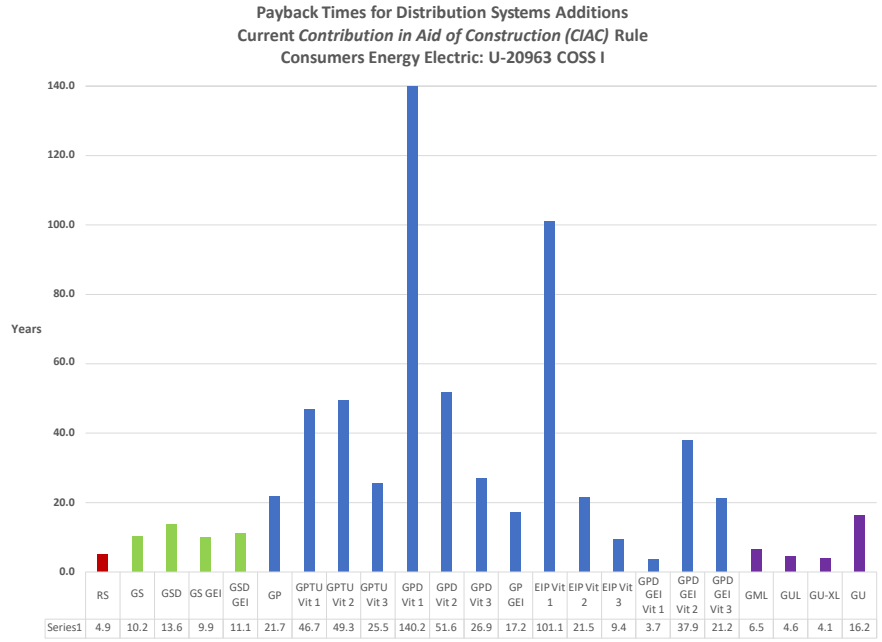
- $Payback\ (yrs) = \frac{3\ yrs}{\left[\frac{Capital\ Related\ Distribution\ Revenue}{Distribution\ Revenue}\right]x\left[\frac{Distribution\ Revenue}{Total\ Revenue}\right]}$

*Consumers Energy CIAC: 3xAnnual Revenue

Payback Times for Distribution System Additions
Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I
And Current *Contribution In Aid of Construction* Formula (3 times Annual Revenue)

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Payback Years w/Distribution Revenue	Capital % of Distribution	Payback years w/Distribution Capital Revenue	% Distribution Capital
RS (Overhead Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	3.52	71%	**4.9**	**30%**
RS (Underground Line)	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	7.12	71%	**10.0**	**30%**
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	7.5	74%	**10.2**	**29%**
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	10.0	74%	**13.6**	**22%**
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	7.3	74%	**9.9**	**30%**
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	8.2	74%	**11.1**	**27%**
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	17.4	80%	**21.7**	**14%**
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	37.4	80%	**46.7**	**6%**
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	39.5	80%	**49.3**	**6%**
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	20.4	80%	**25.5**	**12%**
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	112.3	80%	**140.2**	**2%**
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	41.3	80%	**51.6**	**6%**
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	21.5	80%	**26.9**	**11%**
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	13.8	80%	**17.2**	**17%**
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80.9	80%	**101.1**	**3%**
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	17.2	80%	**21.5**	**14%**
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	7.5	80%	**9.4**	**32%**
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	3.0	80%	**3.7**	**80%**
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	30.4	80%	**37.9**	**8%**
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	17.0	80%	**21.2**	**14%**
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	5.3	81%	**6.5**	**46%**
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	3.7	81%	**4.6**	**66%**
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	3.3	81%	**4.1**	**74%**
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	13.2	81%	**16.2**	**18%**

Sources: Exhibit A-16, Schedule F1, pages 2-3 (Excel Version)

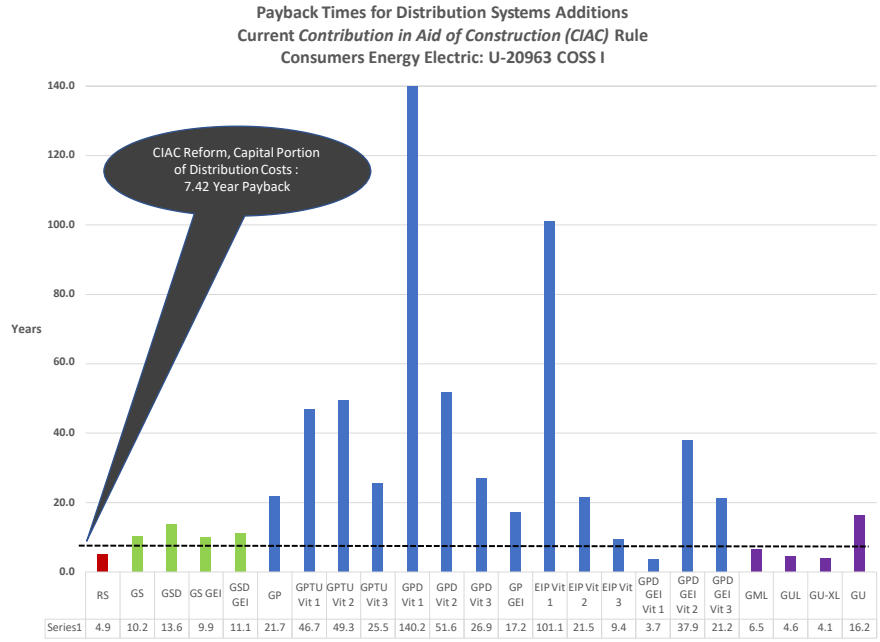


The Same Payback Should be Set for Customers Under all Rate Classes

- The correct **uniform** payback-period is the reciprocal of the *economic carrying cost* of total electric distribution capital investments:
- $$Payback = \frac{1}{Economic\ Carrying\ Cost} = \frac{1}{\left[\frac{Lifecycle\ Average\ Revenue\ Requirement}{Undepreciated\ Balance\ of\ Investment}\right]}$$

- $$Payback \approx \frac{Electric\ Distribution\ Ratebase}{Capital\ Portion\ of\ Distribution\ Revenue\ Requirement}$$

- $$Payback = \frac{\$8{,}145{,}807{,}000}{\$1{,}505{,}709{,}000/yr} = 7.42\ yrs$$ (CE U-20963 COSS version I)



Uniform Payback Under CIAC Reform

Consumers Energy example (based on its U-20963 COSS Version I):

Free allowance = 7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh), for the appropriate rate class), times the end-user's estimated kWh sales.

Would replace current standard of 3 times estimated total annual revenue.

The Capital-Related Portion of Electric Distribution Rate Design Revenue

Rate Schedule	Full Service Sales MWh	Distribution Sales MWh	Production Revenue (thousands)	Distribution Revenue (thousands)	Production Revenue per kWh	Distribution Revenue per kWh	Prod. + Dist. Revenue per kWh	% Distribution	Capital % of Distribution	Capital Portion Distribution Rev. $/kWh
RS	12,621,349	12,621,349	1,334,015	971,991	0.1057	0.0770	0.1827	42%	71%	$ 0.0548
GS	3,750,286	3,758,814	349,084	231,547	0.0931	0.0616	0.1547	40%	74%	$ 0.0455
GSD	2,985,974	3,106,807	266,187	118,096	0.0891	0.0380	0.1272	30%	74%	$ 0.0281
GS GEI	89,373	103,955	8,130	6,621	0.0910	0.0637	0.1547	41%	74%	$ 0.0471
GSD GEI	139,134	199,503	11,795	9,749	0.0848	0.0489	0.1336	37%	74%	$ 0.0361
GP	740,549	781,557	65,712	14,485	0.0887	0.0185	0.1073	17%	80%	$ 0.0148
GPTU Vit 1	429,373	429,373	31,832	2,778	0.0741	0.0065	0.0806	8%	80%	$ 0.0052
GPTU Vit 2	920,450	920,450	71,402	5,867	0.0776	0.0064	0.0839	8%	80%	$ 0.0051
GPTU Vit 3	3,617,577	3,617,577	302,471	52,129	0.0836	0.0144	0.0980	15%	80%	$ 0.0115
GPD Vit 1	1,028,117	2,088,960	53,574	2,988	0.0521	0.0014	0.0535	3%	80%	$ 0.0011
GPD Vit 2	1,096,753	2,316,280	79,178	13,082	0.0722	0.0056	0.0778	7%	80%	$ 0.0045
GPD Vit 3	2,041,798	2,867,360	169,649	38,560	0.0831	0.0134	0.0965	14%	80%	$ 0.0108
GP GEI	90,489	124,414	8,039	3,083	0.0888	0.0248	0.1136	22%	80%	$ 0.0198
EIP Vit 1	383,669	383,669	20,787	800	0.0542	0.0021	0.0563	4%	80%	$ 0.0017
EIP Vit 2	64,327	64,327	3,303	699	0.0513	0.0109	0.0622	17%	80%	$ 0.0087
EIP Vit 3	9,389	9,389	469	309	0.0499	0.0330	0.0829	40%	80%	$ 0.0264
GPD GEI Vit 1	-	2,504	(0)	10	0.0000	0.0039	0.0039	100%	80%	$ 0.0031
GPD GEI Vit 2	17,941	86,329	1,652	871	0.0921	0.0101	0.1021	10%	80%	$ 0.0081
GPD GEI Vit 3	81,110	223,052	7,269	4,296	0.0896	0.0193	0.1089	18%	80%	$ 0.0154
GML	13,118	13,118	672	876	0.0512	0.0668	0.1180	57%	81%	$ 0.0542
GUL	62,386	62,386	3,153	13,632	0.0505	0.2185	0.2691	81%	81%	$ 0.1773
GU-XL	19,268	19,268	939	9,742	0.0487	0.5056	0.5543	91%	81%	$ 0.4102
GU	100,655	100,655	7,599	2,243	0.0755	0.0223	0.0978	23%	81%	$ 0.0181

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

CIAC Reform – Utility Contribution - Based on End User's Estimated Annual (kWh)

7.42 times the capital-related portion of electric distribution rate design revenue ($/kWh)

Rate Schedule	Credit $/kwh
RS	0.40710
GS	0.33805
GSD	0.20860
GS GEI	0.34951
GSD GEI	0.26817
GP	0.11019
GPTU Vit 1	0.03847
GPTU Vit 2	0.03790
GPTU Vit 3	0.08567
GPD Vit 1	0.00850
GPD Vit 2	0.03358
GPD Vit 3	0.07995
GP GEI	0.14731
EIP Vit 1	0.01240
EIP Vit 2	0.06460
EIP Vit 3	0.19592
GPD GEI Vit 1	0.02319
GPD GEI Vit 2	0.05996
GPD GEI Vit 3	0.11450
GML	0.40225
GUL	1.31620
GU-XL	3.04535
GU	0.13424

Applied to estimated annual usage (kWh)

Based on Consumers Energy Proposed Production and Distribution Revenues U-20963 COSS Version I

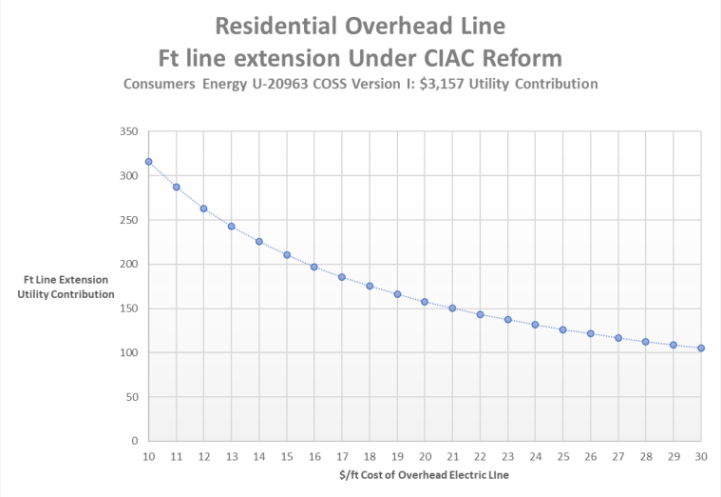
Residential CIAC Overhead Electric Line

Consumers Energy current CIAC rule allows for 1st 600 ft to be covered at the utility expense.

Under CIAC reform, length of "free" extension would depend on cost/ft.

	Current Framework		CIAC REFORM
	Total Revenue	Distribution Revenue	Capital Portion Revenue
Residential kWh/yr	7,754	7,754	7,754
Rate $/kWh	0.1827	0.0770	0.0548
Revenue $/yr	1417	597	425
Payback Period	3		7.42
$ Company Contribution	$ 4,250		$ 3,157

35% TOO HIGH



Conclusions & Recommendations

1) Payback associated with utility contribution-in-aid-of-construction should be **uniform** across all rate classes.
2) The uniform payback (*x Yrs.)* should be based on the **reciprocal of the economic carrying cost of electric distribution capital investment**.
3) The **capital portion** of distribution revenue requirements (%) should be calculated for each customer class (residential, secondary, primary, lighting).
4) The capital portion of the rate-design distribution-revenue ($/kWh) is calculated as product of (3) and the rate design distribution revenue ($/kWh) for full service + ROA sales.
5) Free allowance ($/ kWh of estimated annual usage, for each rate class) is calculated as the product of (4) and the uniform payback period (*2).*
6) The per kWh allowance for each rate class (5) should be reflected in a **schedule**, updated in each general rate proceeding. The per kWh allowance is applied to the end-user's estimated annual usage (kWh)
7) With respect residential **overhead line-extensions**, the maximum # of feet allowed at the utility's expense should be fixed in each rate case, based upon the per kWh residential allowance reflected in (6) times the class average sales per customer (from the COSS) divided by the current cost per foot also set in each rate case.

LRTP Tranche 1 Portfolio Detailed Business Case

June 25, 2022

Summary

- Long Range Transmission Planning (LRTP) addresses the future challenges of the resource fleet evolution
- The LRTP Detailed Business Case summarizes the analysis of the reliability and economic benefits used to demonstrate that the value exceeds the total cost of the projects and supports recommendation of the portfolio
- The LRTP Tranche 1 portfolio provides a total 20-year present value benefit to cost ratio of 2.6

MISO Transmission Planning Objectives

- The goal of MISO Planning is to identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs and support a competitive energy market, policy goals and competitive transmission development
- MISO Board of Directors Guiding Principles
  - Ensure a reliable and resilient transmission system to meet operational needs
  - Make benefits of an economically efficient electricity market available to customers by identifying transmission solutions that enable access to the electricity at the lowest total electric system cost
  - Support federal, state and local energy policy and member goals by planning for access to a changing resource mix
  - Provide an appropriate cost allocation mechanism that ensures that costs are allocated in a manner roughly commensurate with the projected benefits
  - Analyze system scenarios and make results available to energy policy makers and stakeholders to provide context and inform their choices
  - Coordinate planning process with neighbors and work to eliminate barriers to reliable and efficient operations

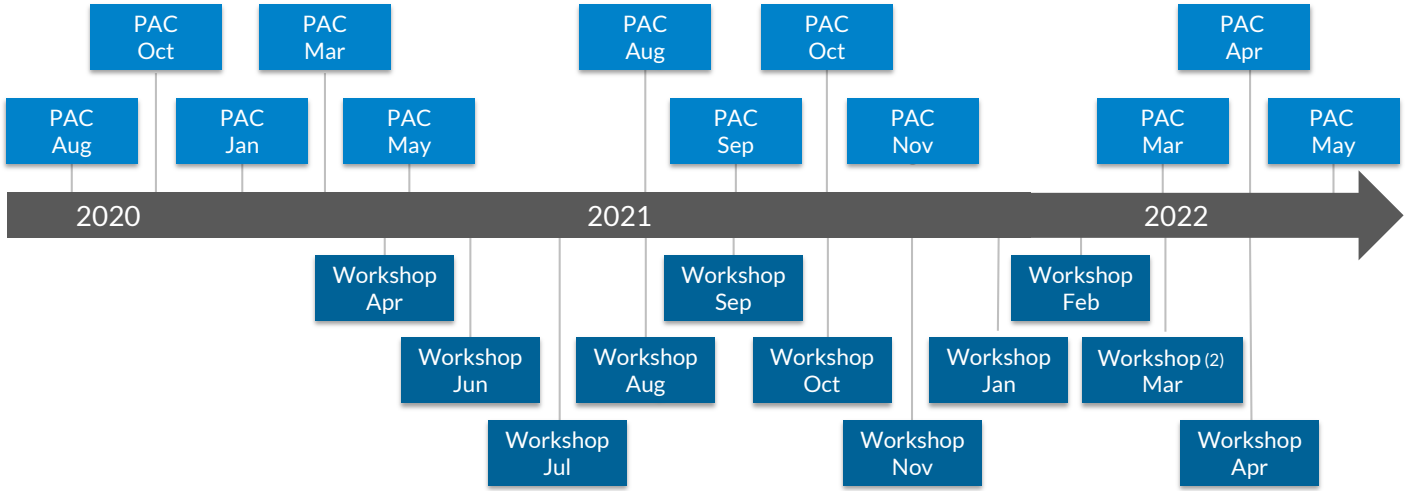
Long range focus on system planning needed in response to unprecedented industry changes

- The initial 2019 MISO Forward report began to examine industry trends around resource and technology developments that highlighted growing challenges around resource availability, flexibility and visibility of the resource fleet in meeting future energy needs
- The Renewable Integration Impact Assessment explored challenges of increased renewable penetration and identified significant reliability issues that would need to be addressed through possible reinforcements to maintain robust performance
- In recognition of the need for more long-term proactive planning to meet the pace of change, Long Range Transmission Planning began with a conceptual roadmap of ideas to help guide development of planning analysis that would be needed to identify possible transmission solutions

Timeline of LRTP development

- MISO introduced the LRTP conceptual roadmap to stakeholders in June 2020 to begin discussions on the study scope and approach
- MISO began a series of technical discussions in Aug 2020 to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings
- MISO initiated discussions on cost allocation mechanisms with the Regional Expansion Criteria and Benefits Working Group in Feb 2021 to investigate possible Tariff changes that would be needed before recommendation of projects
- MISO introduced Business Case development in the Sept 2021 LRTP workshop to begin identifying the benefit components and defining the metrics for quantifying the benefits provided by the initial portfolio of LRTP transmission investments

Workshops and Stakeholder feedback are critical to the LRTP process and success



LRTP Projects must meet one of three MVP criteria defined in the MISO Tariff

MISO Tariff - Attachment FF, II.C.2...

a. *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade*

b. *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*

c. ***Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.***

The MISO MVP Tariff further defines the 'specific types of economic value' which may be included

MISO Tariff - Attachment FF, II.C.5...

a. *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.*

b. *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*

c. *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*

d. *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*

e. *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.*

The objective of LRTP is to enable reliable and economic delivery of energy in the future with lower-carbon resources

- Provide a cost-effective solution to allow future resources to serve load throughout the footprint
- Enable access to lower-cost energy production
- Provide more flexibility in fuel mix for customer choice
- Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply

The scope of LRTP business case analysis includes quantifying the reliability and economic benefits

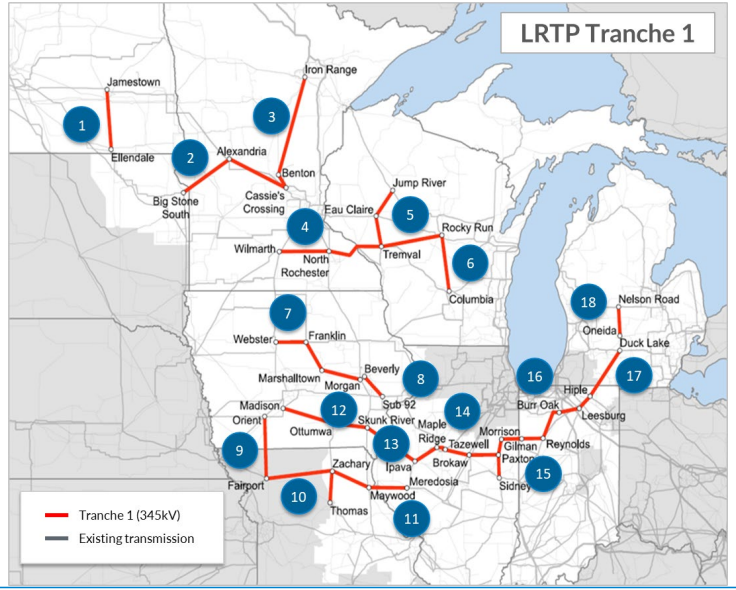
A. Congestion and fuel savings
B. Avoided capital costs of local resource investments
C. Avoided transmission investment
D. Reduced resource adequacy requirements
E. Avoided risk of load shedding
F. Decarbonization
G. Reliability issues addressed by LRTP
H. Other qualitative and indirect benefits

LRTP business case analysis uses a range of variables

- LRTP benefits examine value over the 20- to 40-year period from the in-service date (All projects assumed in service by 2030)
  - Benefit/cost calculations are evaluated on a 20-year time horizon
  - Additional benefits are shown for the 40-year horizon to align with assumed life of the assets
- LRTP benefits are evaluated for a range of discount rates from 3.0 – 6.9%
  - The social discount rate of 3.0% represents the value a ratepayer would typically receive on their risk-adjusted investment
  - The Weighted Average Cost of Capital (WACC) of 6.9% is the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments

Tranche 1 Portfolio proposal is the culmination of two years of Futures development, modeling, and engineering and represents the most complex transmission planning study effort in MISO's history

- Portfolio embodies needed transmission for the ever-changing fleet
- Addresses needs across the MISO Midwest subregion
- Analysis of reliability needs and benefits associated with Future 1 resource expansion



Total portfolio cost estimate for LRTP Tranche 1 is $10.3 B for projects located across the MISO Midwest subregion

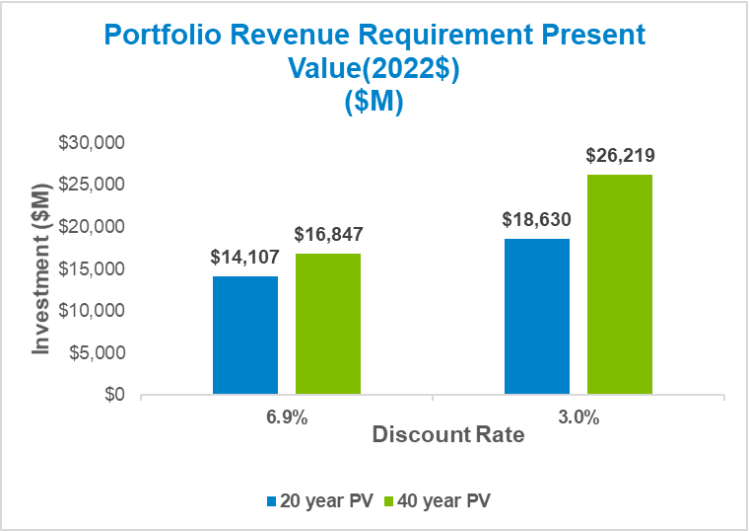
ID	Project Description	Est. Cost ($M, 2022)
1	Jamestown – Ellendale	$439
2	Big Stone South – Alexandria – Cassie's Crossing	$574
3	Iron Range – Benton County – Cassie's Crossing	$970
4	Wilmarth – North Rochester – Tremval	$689
5	Tremval – Eau Clair – Jump River	$505
6	Tremval – Rocky Run – Columbia	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	$755
8	Beverly – Sub 92	$231
9	Orient – Denny - Fairport	$390
10	Denny – Zachary – Thomas Hill – Maywood	$769
11	Maywood – Meredosia	$301
12	Madison – Ottumwa – Skunk River	$673
13	Skunk River – Ipava	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	$572
15	Sidney – Paxson East – Gilman South – Morrison Ditch	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	$261
17	Hiple – Duck Lake	$696
18	Oneida – Nelson Rd.	$403
	Total Project Portfolio Cost	**$10,324**

Costs as of 7/25/2022
(costs represent "overnight" costs)

The LRTP Tranche 1 portfolio cost (20-year and 40-year present value at 6.9% and 3.0% discount rate)

The total capital cost of LRTP Tranche 1 portfolio is estimated to be $10.3B

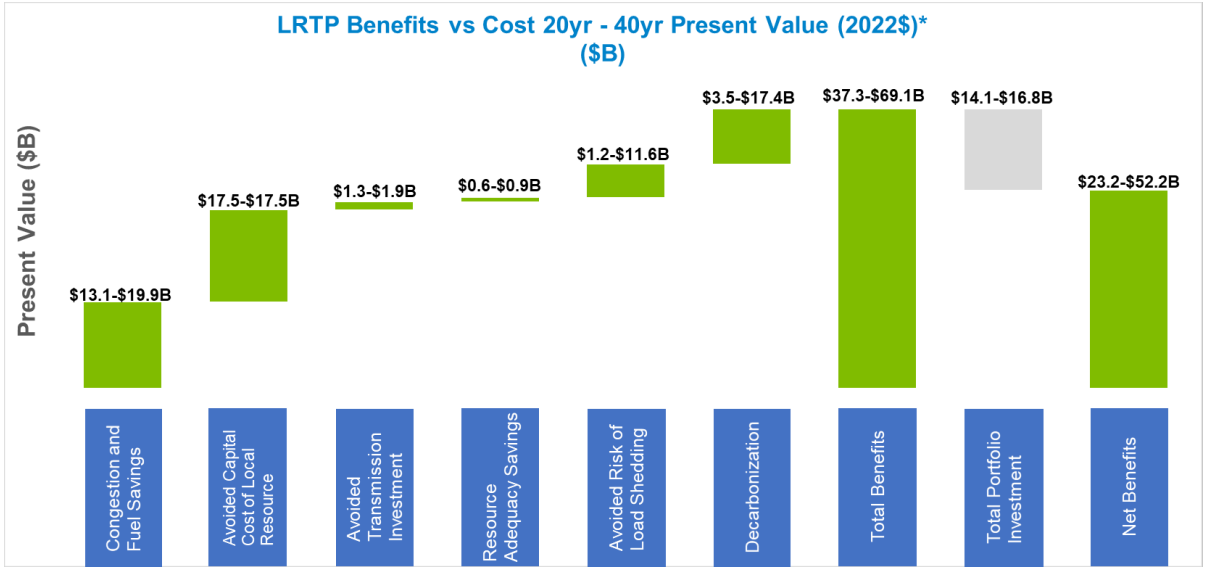
The 20-40yr Present Value (in 2022$) of the portfolio total revenue requirement is expected to be in the range of $14.1B-$16.8B*



*6.9% Discount Rate

Benefit Metrics

The business case analysis indicates total economic benefits significantly exceed cost of the Tranche 1 LRTP portfolio



*6.9% Discount Rate

A. Congestion and Fuel Savings

APC Benefits will be determined by comparing MISO Midwest APC in the LRTP Reference Case with the MISO Midwest APC in the LRTP Change Case

Make-up of LRTP Reference Case Model

- MTEP Topology
- Future Load Forecast
- Existing + Signed GIA
- RRF DGPV
- IRP/RRF Battery Storage
- IRP/RRF Thermal
- Renewable RRFs < 5% DFAX

Compare APC Change

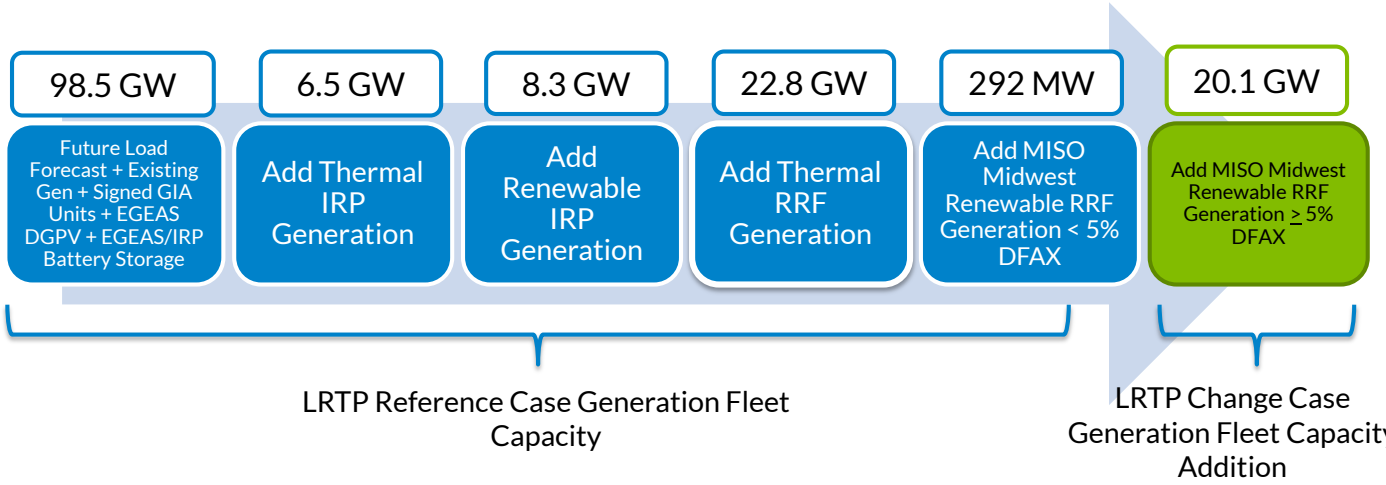
Make-up of LRTP Change Case Model

- Reference Case
- Renewable RRFs ≥5% DFAX
- LRTP Transmission

- The LRTP Reference Case represents necessary generation to serve Futures Load Forecast (on copper sheet)
- The LRTP Change Case includes Renewable RRFs located in MISO Midwest which have ≥ 5% DFAX on reliability constraints addressed by LRTP projects

A. Congestion and Fuel Savings

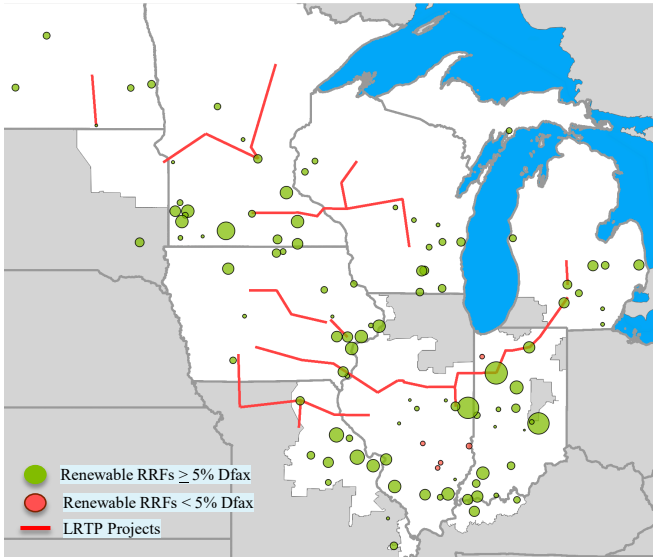
MISO Midwest-focused Reference Case generation determination process and results to meet copper sheet energy requirements in Future 1



A. Congestion and Fuel Savings

LRTP Tranche 1 projects congestion and fuel savings results

Present Value	20 year PV (Millions-2022$)		40 year PV (Millions-2022$)	
Discount Rate	6.9%	3.0%	6.9%	3.0%
CAZ				
1	$3,169	$4,455	$4,668	$8,797
2	$1,049	$1,511	$1,667	$3,313
3	$2,195	$3,060	$3,151	$5,823
4	$1,352	$1,934	$2,107	$4,133
5	$1,471	$2,078	$2,205	$4,210
6	$2,884	$4,133	$4,517	$8,890
7	$1,006	$1,432	$1,543	$2,993
	$13,125	**$18,603**	**$19,858**	**$38,160**



B. Avoided Capital Costs of Local Resource Investments

Resource capital investments can be avoided by taking advantage of broader regional renewables instead of purely local resources

- Past experiences with transmission studies like the 2011 Multi-Value Projects indicate that a regional approach will be more cost-effective than a purely local buildout:
  - Magnitude, cost, & locations of resources differ based upon approach used
  - Regional transmission is the bridge between these scenarios
- To determine avoided capital cost of local resource investment savings created by LRTP transmission MISO developed
  - EGEAS LBA (local) granularity expansion models utilizing Future 1 assumptions
  - Calculation to relate the LBA and Regional expansion to LRTP transmission and determine what the avoided capital costs of local resource investments would be

B. Avoided Capital Costs of Local Resource Investments

Overview of EGEAS LBA expansion models used to determine what a local build out would be

- Each EGEAS run represents one of the 39 LBAs in MISO, with a Future 1 basis
  - The runs treat each LBA as its own pool.
  - Each LBA then self-constructs resources necessary to meet the simulation constraints such as PRM and emissions.
  - Utilizes the same assumptions as the regional Future 1 analysis and resources are ascribed to LBAs based on resource ownership.
  - Capacity purchases are enabled for the first year to meet each LBA's PRM and is driven by the construction lead time for new resource alternatives.
  - LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.
- The MISO PRM value of 18% is scaled for each LBA based upon its alignment to the MISO coincident peak.

B. Avoided Capital Costs of Local Resource Investments

Calculation to relate the LBA and Regional expansion to LRTP transmission to determine cost savings

- Calculation Overview
  - Due to Regional and LBA modeling assumptions, the avoided capital costs of local resources investments can not be determined by subtracting Regional expansion costs from the total LBA expansion costs (doing so would over-state realized benefit)
  - Regional and LBA Regional Resource Forecasting (RRF) expansion reflects Local Resource Zones (LRZ) that make up MISO Midwest (LRZ 1 – LRZ 7)
  - Enabled RRF capacity reflects RRF resources enabled by LRTP transmission, meaning those resources have ≥ 5% Dfax for LRTP transmission resolved reliability issues
  - Utilizes costs of LRTP transmission enabled capacity to infer avoided capital cost of local resources savings

$$Adjusted\ Capital\ Cost_{LBA\ Expansion}$$
$$= \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})}$$

$$Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments$$
$$= Adjusted\ Capital\ Cost_{LBA\ Expansion} - Enabled\ RRF\ Capital\ Cost_{Region\ Expansion}$$

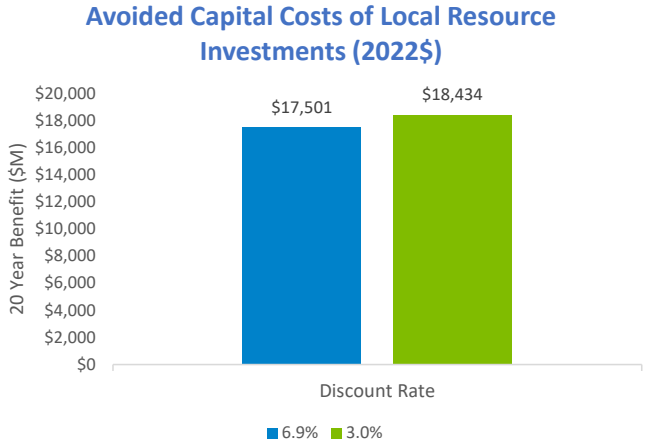
B. Avoided Capital Costs of Local Resource Investments

Avoided capital costs of local resource investments benefit

$$Adjusted\ Capital\ Cost_{LBA\ Expansion}$$
$$= \sum_{Year\ 2020}^{Year\ 2040} \$16.0B \times \frac{90{,}969\ MW}{43{,}431\ MW} = \$33.58B$$

$$Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments$$
$$= \$33.58B - \$16.0B = \$17.5B$$

- LRTP enables regional resource sharing and reduces local overbuild yielding a 20-year present value benefit of $17.5B*



* using the 6.9% Discount Rate

C. Avoided Transmission Investment

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Captures the avoided cost of reliability upgrades and replacements that will not be required in the future as a result of the addition of LRTP projects
- Includes facilities where thermal loading is approaching the rating but not overloaded
  - Avoided reliability upgrades are determined by using the 10-year and 20-year analysis results to project future loading on facilities loaded near the rating with and without LRTP projects

$$Flow_{proj} = Flow_{20} + (Flow_{20}-Flow_{10})$$

Example: Facility is included in avoided costs of future transmission investment							
Line name	kv	RatingMVA	case	Flow10	Flow20	Flowproj	
Forest - Valley 161kV	161kV	335	w/o LRTP	324	331	338	without LRTP, future upgrade is needed
			w/ LRTP	315	322	329	with LRTP the overload is resolved

- Includes replacement of existing facilities due to age and condition that would not be required because the LRTP projects use existing ROW of aging facilities

C. Avoided Transmission Investment

Re-use of existing ROW for LRTP projects offsets the costs of age and condition replacement of aging facilities

- The LRTP Tranche 1 portfolio of projects potentially use 836 miles of existing facilities where age and condition of the facilities is expected to require replacement of assets
- Construction of LRTP on the existing right-of-way would include replacement of existing structures and equipment that would avoid the future cost of replacing the existing facilities

C. Avoided Transmission Investment

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Avoided transmission investment uses exploratory cost estimates based on type of facility improvement required
- Like in the 2011 MVP business case, an adjustment is applied to avoided reliability upgrades >=345kV to reduce value by 50% to account for potential production cost benefits provided by the upgrades
- Capital investment for future transmission is assumed to be spread equally over the 5-year period prior to the in-service date (2040) of the avoided reliability upgrades
- The Annual Transmission Revenue Requirement was calculated to obtain the 20-year net present value discounted to 2022$ values

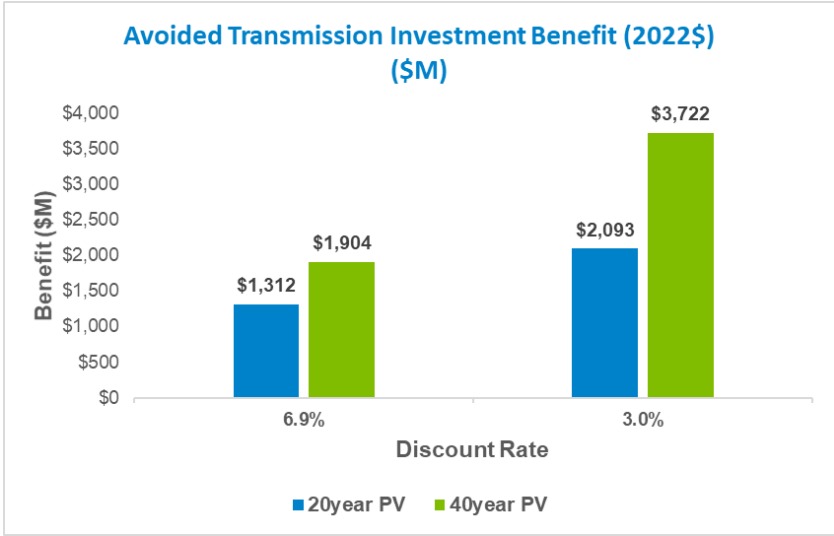
Facility Improvement Type	Unit Cost ($M)	Quantity/Miles	Cost ($M)*
Bustie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

*MISO Estimates

C. Avoided Transmission Investment

LRTP provides benefits by eliminating the need for other transmission projects

- LRTP avoids the need for transmission investment that yields 20- to 40-year present value benefits from $1.3B to $1.9B*



* using the 6.9% Discount Rate

D. Reduced Resource Adequacy Requirements

The resource adequacy benefits are related to an increase in transfer capability and a reduction in the total LCR*

- As LRTP increases the transfer capability within the footprint, the increase in transfer limit is quantified
- The potential economic value unlocked by the availability of least-cost resources across the footprint due to increase in transfer capability is estimated
- A two-step process was developed to quantify the LCR reduction benefits and approximate the monetary value

*Local Clearing Requirement

D. Reduced Resource Adequacy Requirements

Step 1: Perform a transfer analysis to determine the LCR for each local resource zone (LRZ)

1. Calculate the capacity import limit (CIL) for each LRZ and case*
   - Determine the import limit (e.g., TrLim) for each LRZ and study case
   - Determine the area interchange for each LRZ and study case
2. Determine the LCR for each LRZ and case*
   - The LRR UCAP** percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ

Local Resource Zone	CIL (Base)	CIL (With LRTP)	Delta CIL (MW)
LRZ1	5412	6070	658
LRZ2	4188	5223	1035
LRZ3	5062	6453	1391
LRZ4	7117	7609	492
LRZ5	6131	6183	52
LRZ6	6005	6171	166
LRZ7	3367	4659	1292

*With and without LRTP projects (14 total cases) | **Unforced capacity

D. Reduced Resource Adequacy Requirements

Step 2: Monetize the benefits identified in Step 1

1. The 2040 unforced capacity for each LRZ is determined using forced outage rates (thermal) and ELCC* (non-thermal)
2. The excess capacity within each LRZ is calculated as follows:
   - Excess Capacity = 2040 Unforced Capacity – LCR (without LRTP)
3. The RA benefit is estimated as follows:
   - If Excess Capacity < 0 → Benefit = (CONE**) x (-Excess Capacity)
   - If Excess Capacity > 0 → Benefit = $0/year

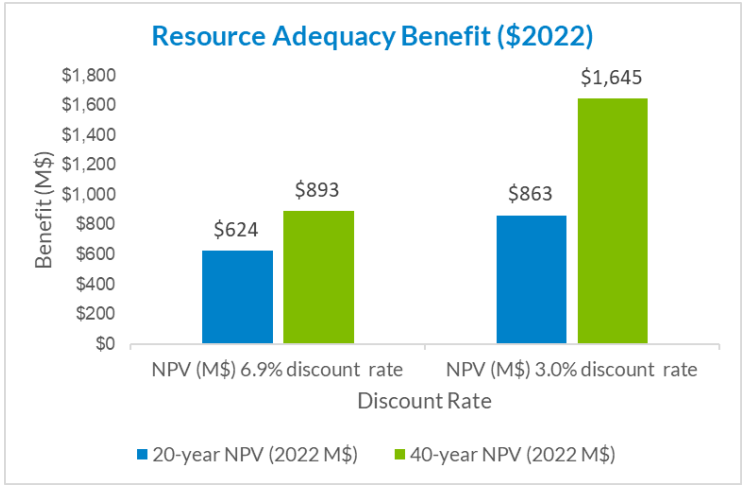
LRZ	1	2	3	4	5	6	7
PY22-23 CONE ($/MW-yr)	$91,270	$89,490	$86,380	$90,300	$97,190	$89,040	93,770

* Effective Load Carrying Capability | ** Cost of new entry

D. Reduced Resource Adequacy Requirements

The annual economic benefits related to resource adequacy are estimated to be $44M per year

- LRTP reduces the total LCR and yields 20- to 40-year present value benefits from $624-$893M*



* using a 6.9% Discount Rate

E. Avoided Risk of Load Shedding

LRTP transmission can reduce risk of load shedding due to unplanned generation events

- Large scale unexpected loss of generation in an area presents a risk of significant load shedding
- Transmission reinforcements provided by LRTP increase transfer capability to allow load to be served from resources located in other areas
- Benefits are associated with avoided risk of load shedding focus on risks of large-scale generation loss caused by severe weather
  - Renewable production is dependent on weather conditions
  - Thermal resources have operational limitations under extreme temperature conditions
- Weather-related events occur in various scales
  - Event scenarios examine generation and load balance after loss of significant resources to determine if import capability is sufficient to cover generation deficiency
  - Risk of load shedding exists where generation deficiency cannot be covered by existing import capability
- Benefits are calculated using Value of Lost Load (VOLL) ranging from $3500-$23,000* /MWh

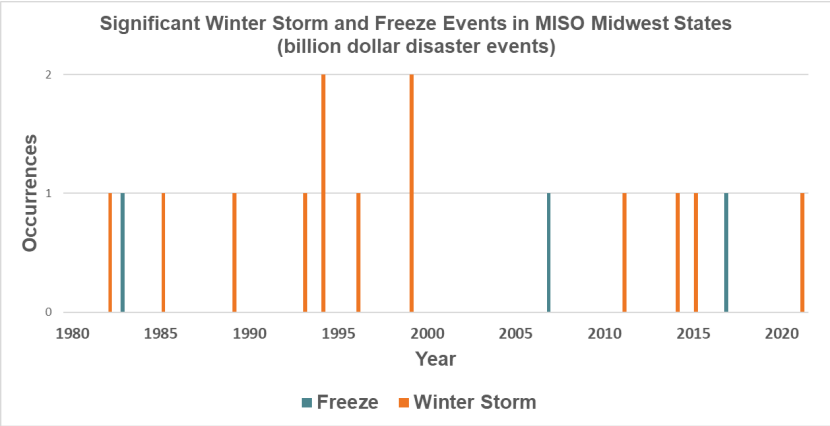
*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

E. Avoided Risk of Load Shedding

Analysis of risk focus on recurring severe winter weather events and variability of renewable resources

Severe winter weather events have been occurring at regular intervals over the past 40 years

More recent extreme winter events (e.g., Uri) have brought operational challenges caused by unplanned generation outages

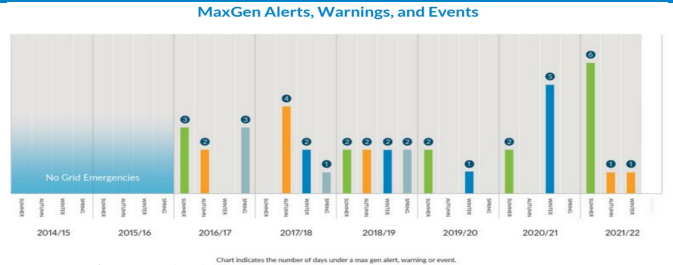


Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

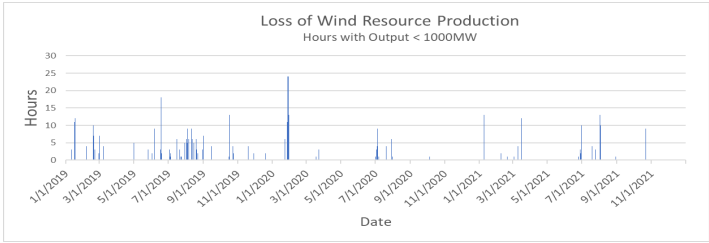
E. Avoided Risk of Load Shedding

Weather conditions affect the availability of resources

- Generation capacity events have become more common in recent years with the existing resource fleet
- Weather impacts will become more significant with greater dependency on renewable resources and gas-fired dispatchable resources
- Renewable resources regularly experience periods of low output lasting several hours



Source: *MISO's Response to the Reliability Imperative,*
https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

E. Avoided Risk of Load Shedding

LRTP transmission can reduce risk of load shedding due to unplanned loss of generation due to severe winter weather events

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

LoadLossMW =
$GenMW_{net}$ – 1.05 * LoadMW – TxLossMW + Capacity Import Limit(MW)
where $GenMW_{net} = GenMW_{cap} – GenMW_{loss}$

+

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

LoadLossMW =
$GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability(MW)
where $GenMW_{net} = GenMW_{cap} – GenMW_{loss}$

E. Avoided Risk of Load Shedding

Total avoided risk of load shedding includes all winter event scenarios

Zonal

zone	GenLoss(therm)	GenLoss(wind)	GenLoss(solar)	Gen Remaining		Gen Surplus	CIL (no LRTP)	shortfall	newCIL (LRTP)	CIL diff	benefit
1	6607	6693	4612	12178		-5083	5412	-329	6070	658	
2	5369	1082	1049	8246		-3527	4188	-661	5223	1035	
3	3762	8001	3306	9529		-195	5062	-4867	6453	1391	
4	3358	2442	2065	6645		-2532	7117	-4585	7609	492	
5	2414	691	1185	5499		-2092	6131	-4039	6183	52	
6	7362	1461	2858	11873		-6680	6005	675	6171	166	166
7	6164	1714	3445	13387		-3574	3368	206	4659	1291	206
							Total Avoided Load shed				372
							Assumed duration				16
							Total Avoided Load shed hours				5954

Regional

zone	GenLoss(th)	GenLoss(w)	GenLoss(s)	Gen Remaining	Extimp	Gen Surplus	TTC (no LRTP)	shortfall	newTTC (LRTP)	TTC diff	benefit
Lrz1-3	19672.34	15776.433	8967.45	26018.897	7500	-20239.783	7260.8	12978.983	9391	2130.2	2130.2
Lrz4-7	24123.405	6307.11	9553.2	32579.295	0	-19702.2	6192.5	13509.695	8185	1992.5	1992.5
							Total Avoided Load shed				4122.7
							Assumed duration				16
							Total Avoided Load shed hours				65963.2
							Total for all Events				71917.1

Risk of load shedding is assumed to occur every three years based on the frequency of severe winter weather events

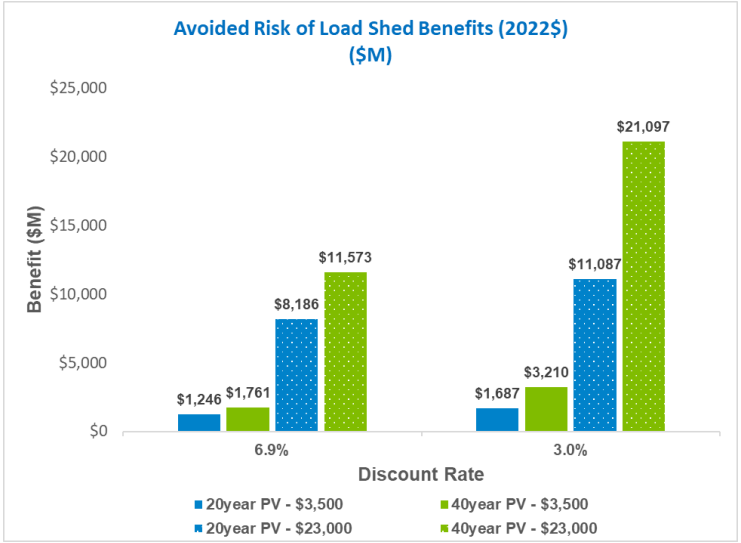
E. Avoided Risk of Load Shedding

Value of avoided risk of load shedding is determined by applying the Value of Lost Load (VOLL)

Avoided Risk of Load Shed Value($) = VOLL * LoadLossMW * duration(hrs)

where VOLL – Value of Lost Load: $3500- $23,000*

LRTP reduces risk of load shedding and provides 20-40 year net present value benefits of $1.2B to $11.6B**



*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

 ** using a 6.9% Discount Rate

F. Decarbonization

MISO has developed a carbon price range to capture LRTP's long-term benefits of reducing CO_2 emissions by enabling reliable delivery of low-cost, clean energy

- Calculate emissions reduced between LRTP Reference Case and LRTP Change Case used for the congestion and fuel cost savings benefit metric.
- Convert to metric tons.
- Using 2.5% annual inflation and discount rates below, apply range of carbon costs to calculate 20- and 40-year NPV of reduced carbon emissions.

20-Year CO_2 Emissions Reduced: 399M metric tons
40-Year CO_2 Emissions Reduced: 677M metric tons

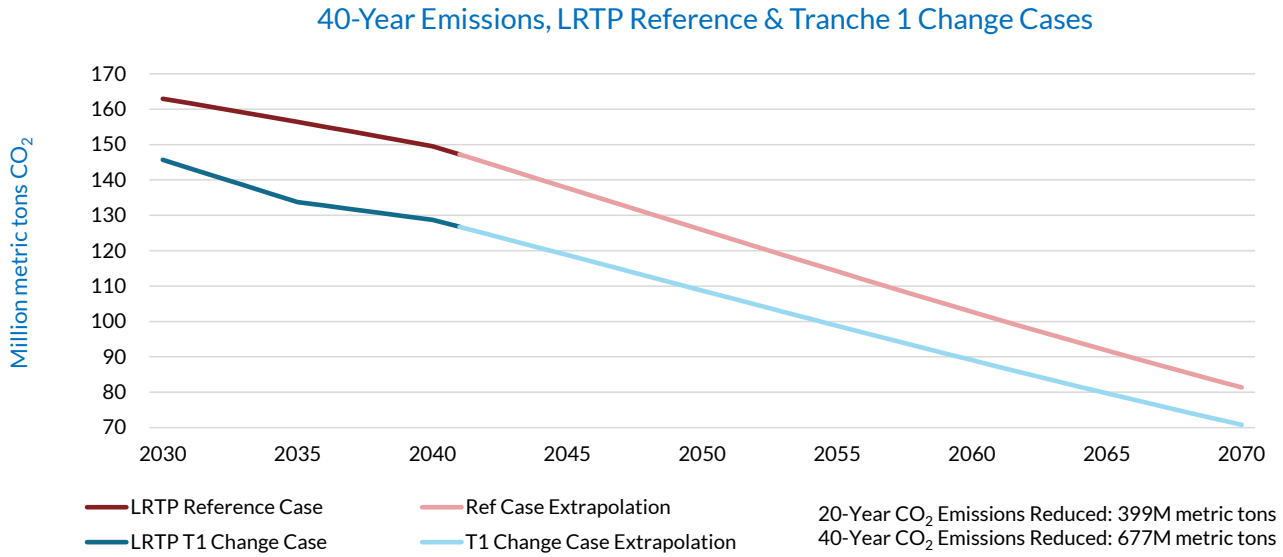
	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M)	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M)	$4,548	$17,364	$7,818	$29,498

Prices converted to 2022$. Full range of carbon prices demonstrated in previous workshops.
20-year and 40-year benefits = projects' in-service value to 2050 and 2070, respectively.
Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

Minnesota Public Utility Commission (2022 Low)
Federal = Average of 45Q Federal Tax Credit and Federal Social Cost of Carbon

F. Decarbonization

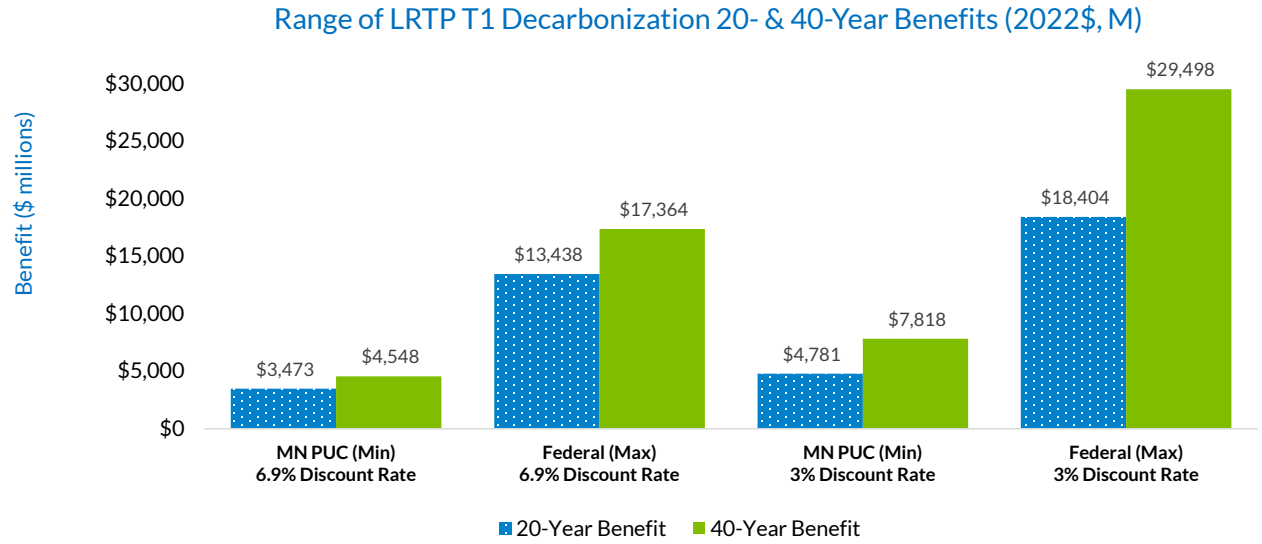
LRTP Change Case illustrates the emissions reduced through enabled resources



Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

F. Decarbonization

With the price range considered, Decarbonization benefits range from $3.5B to $29.5B over 40 years of project life



NPV benefits in millions of 2022 dollars, including 2.5% annual inflation for Min/Max prices at discount rates above.
20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

G. Reliability issues addressed by LRTP Tranche 1

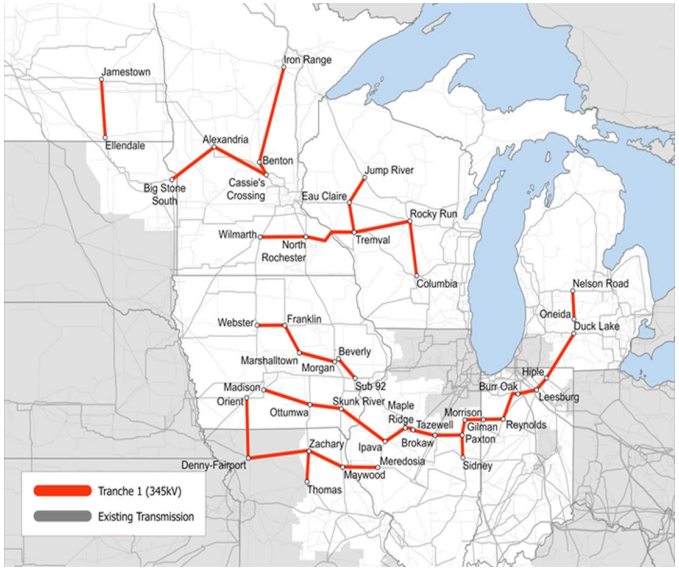
LRTP Tranche 1 portfolio allows reliable delivery of energy from future resource portfolio to serve load across the footprint

Reliability analysis was performed to assess the impact of the LRTP projects on steady state system performance

- Thermal and voltage issues were mitigated by the LRTP projects under base conditions reflecting varying load and dispatch patterns
- Additional upgrades were identified to mitigate issues resulting from the addition of LRTP projects

Transfer Analysis

- Improvements in transfer capability allows energy requirements to be met under varying dispatch patterns driven by differences in weather conditions across the Midwest subregion
- LRTP projects provides more robust interconnection to improve system stability during periods of heavy power transfers



G. Reliability issues addressed by LRTP Tranche 1

MN-Dakotas Reliability Needs Addressed

Jamestown - Ellendale 345kV, Big Stone South – Alexandria - Cassie's Crossing 345kV

- Assists in transport of energy out of Dakotas toward central MN and Twin Cities area
- Relieves issues on the 230kV system and improves connections between 345kV systems to improve long distance movement of power
- Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
- Performs better than other six alternatives removing almost all existing congestion with only minimal new congestion.

Iron Range - Benton County – Cassie's Crossing 345kV

- Provides low impedance path from Northern to Central Minnesota improving Voltage stability and transfer performance with >10% increase in Manitoba Import limit performing better with higher capacity and lower cost than the four other alternatives
- Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

MN-WI Reliability Needs Addressed

Wilmarth - N. Rochester – Tremval - Eau Claire - Jump River
Tremval – Rocky Run – Columbia 345kV

- Provides outlet for renewables located in Minnesota
- Congestion relief and raises stability limit by 250MW to increase transfer capability on the MN-WI interface
- Improves connectivity to serve load centers
- Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

Central Iowa Reliability Needs Addressed

Webster-Franklin-Marshalltown-Morgan 345kV
Beverly-Sub92 345kV

- Provides outlet for renewables located in IA and SW Minnesota
- Provides corridor for delivery of energy to load centers in central portions of MISO
- Addresses 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies

G. Reliability issues addressed by LRTP Tranche 1

Iowa, Illinois, Indiana, Michigan Reliability Needs Addressed

Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345kV
Paxton – Sidney 345kV
Oneida – Nelson Road 345kV

- Delivers significant increase in transfer capability to support generation deficient areas due to unexpected decrease in renewable output
- Mitigates 28 thermal overloads in Michigan, 16 thermal overload in Indiana, 19 thermal overloads in Missouri and Illinois, 14 thermal overloads in Iowa
- Provides more robust performance under large shifts in dispatch of generation across the region

G. Reliability issues addressed by LRTP Tranche 1

Missouri Reliability Needs Addressed

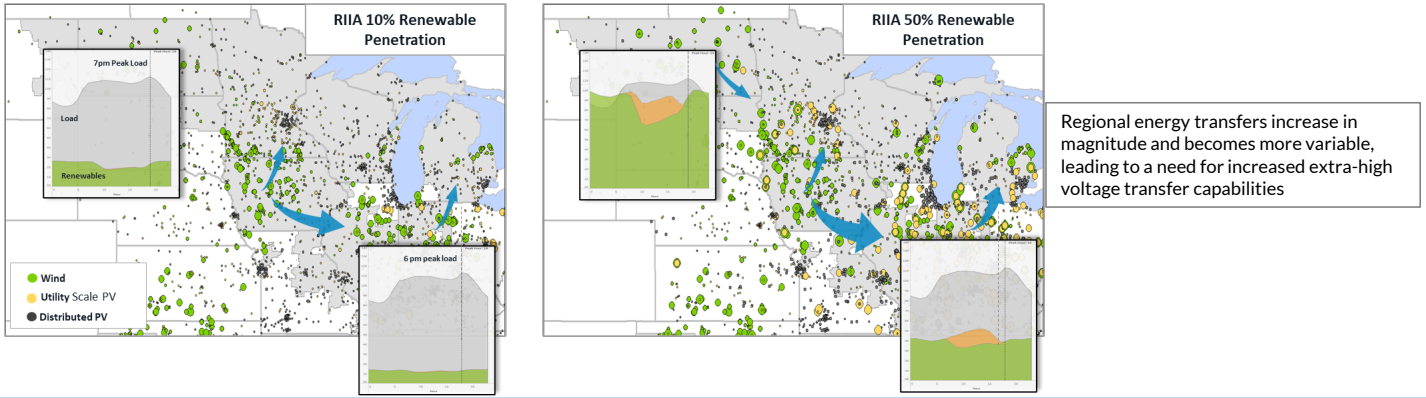
Orient – Fairport – Zachary – Maywood – Meredosia 345kV
Zachary – Thomas Hill 345kV

- Provides increased transfer capability of 250MW West-to-East and 438MW MISO-to-Michigan to address voltage collapse conditions in Missouri
- Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
- Provides more robust performance under large shifts in dispatch of generation across the region addressing 14 thermal overloads

H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- An increasingly connected system is needed to balance generation resource variability across an increasingly heterogeneous footprint.
- Additional transmission reinforcements provided by LRTP increases the ability of the system to manage the increasing different regional flows and operational events without adverse impacts to system performance



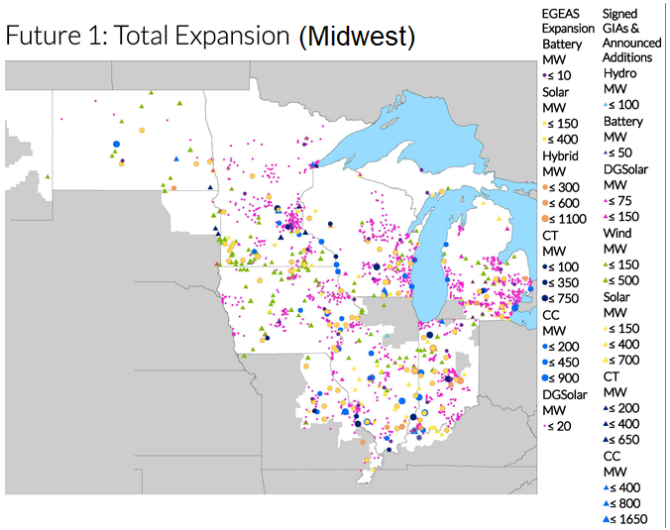
Regional energy transfers increase in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities

Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Increased transmission capacity better leverages the geographic and fuel diversity of the broader footprint to more effectively manage dispatch variability due to changing weather patterns



MISO Futures Report (December 2021) https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

H. Other Qualitative and Indirect Benefits

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

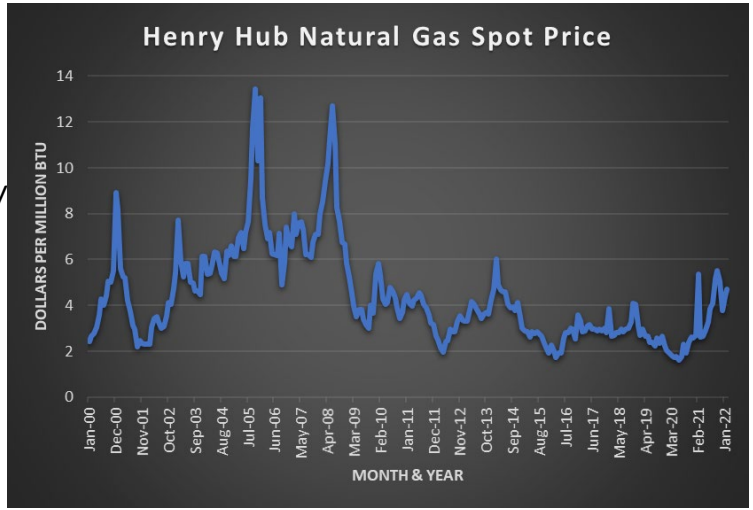
- Transmission expansion provides additional operational flexibility and allows more opportunity for planning of transmission and generation outages with less risk of operational issues or rescheduling of outages
- Transmission expansion allows better use of the transmission network and provides more flexibility to meet changing customer needs and diverse policy goals

Congestion and Fuel Savings Natural Gas Price Sensitivity

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

LRTP projects decrease system-wide impacts of natural gas volatility

- Local transmission investment cannot completely insulate electric consumers from the risks associated with fuel price volatility
- However, LRTP projects offset the risk by providing additional congestion and fuel savings benefits under high natural gas prices by enabling renewable energy
- Congestion and fuel savings benefits were analyzed through a series of production cost analyses, with higher natural gas cost assumptions



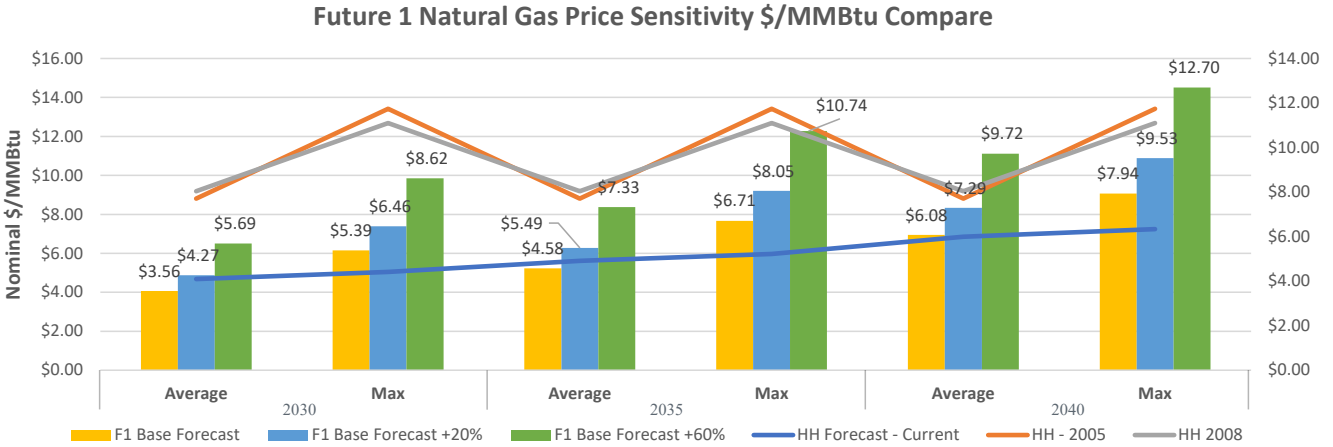
A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

MISO Futures used for the LRTP study utilized new natural gas price forecast methodology

- GPCM Natural Gas Market Forecasting System was used to develop forecasts instead of locked-down Henry Hub (HH) and blend of three different forecasts
- Use on base forecast gas price in EGEAS for all Futures
- Using the same assumptions, but referencing PROMOD output, create Future-specific and area-specific gas prices for use in PROMOD models
- A range of gas prices were tested on LRTP Reference and Change Case PROMOD models

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

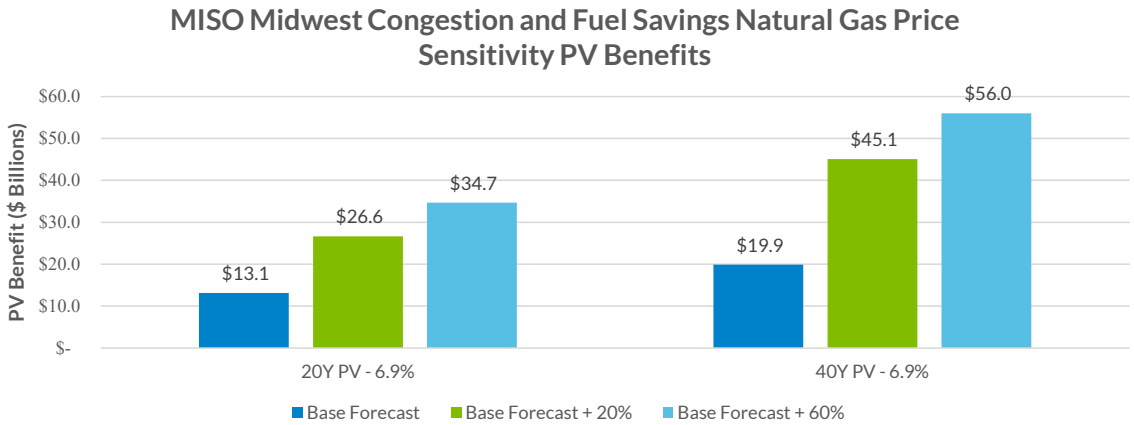
Future 1 Natural Gas prices were increased by 20 – 60% for sensitivity evaluation



- When comparing to HH prices, a 20% increase was found to facilitate the best starting point, which ensures year 2040 average price is greater than HH projected price
- A 60% increase was selected as the endpoint, to create a year 2040 value that represented HH highest sale prices historically (2005 and 2008)

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

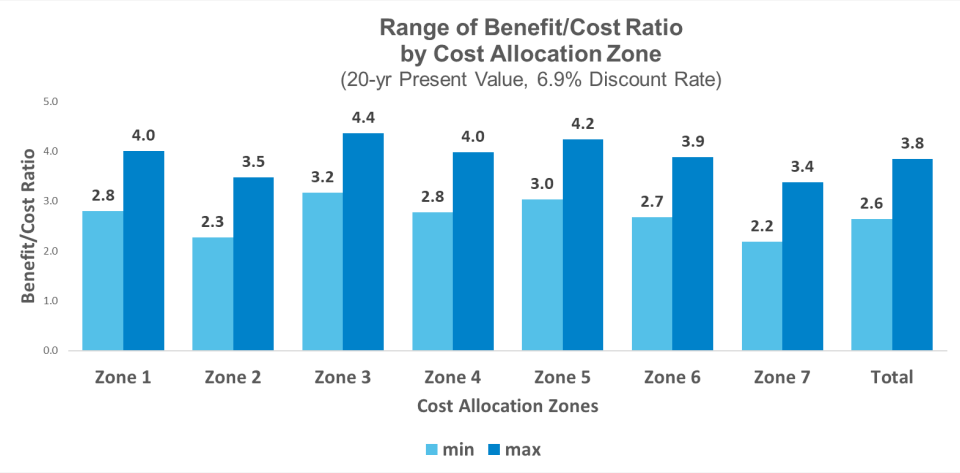
LRTP Tranche 1 transmission will provide greater congestion and fuel savings as natural gas price increases



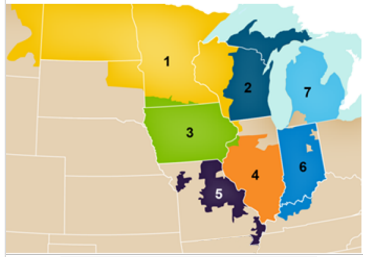
- 20% price increase generates a $13.4B congestion and fuel savings increase
- 60% price increase generates a $21.5B congestion and fuel savings increase

Distribution of Benefits for Midwest Subregion

The benefits provided by the LRTP Tranche 1 Portfolio are distributed across the Midwest subregion in a manner commensurate with the costs



Map of Midwest Cost Allocation Zone Boundaries*



*MISO Tariff, Attachment WW

For the lower range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 2.2 where VOLL=$3,500 and with a carbon price of $12.55 per metric ton

Footprint Benefits (minimum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$248	$168	$133	$121	$96	$233	$246	**$1,246**
Decarbonization**	Based on load ratio share	$691	$468	$370	$339	$268	$651	$687	**$3,473**
Total Benefits		$7,867	$4,326	$4,763	$3,824	$3,311	$7,094	$6,096	**$37,281**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		2.8	2.3	3.2	2.8	3.0	2.7	2.2	**2.6**

*VOLL=$3,500
**Carbon Price=$12.55 /metric ton

For the upper range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 3.4 where VOLL=$23,000 and with a carbon price of $47.80 per metric ton

Footprint Benefits (maximum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$1,629	$1,103	$872	$798	$632	$1,534	$1,618	**$8,186**
Decarbonization**	Based on load ratio share	$2,673	$1,811	$1,431	$1,311	$1,037	$2,519	$2,656	**$13,438**
Total Benefits		$11,231	$6,604	$6,563	$5,472	$4,616	$10,262	$9,438	**$54,187**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		4.0	3.5	4.4	4.0	4.2	3.9	3.4	**3.8**

*VOLL=$23,000
**Carbon Price=$47.80 /metric ton

Conclusion

The LRTP Tranche 1 portfolio provides a regional transmission solution to addressing future energy needs

- For a capital investment of $10.3B, the LRTP portfolio provides $37.0B in financially quantifiable benefits over 20 years
- LRTP transmission projects enhance system performance to maintain reliable operation in the future with more variability and uncertainty in energy supply
- The LRTP Tranche 1 portfolio reflects a cost-effective set of solutions that enable delivery of energy to support future energy requirements of the MISO customers
- The LRTP Tranche 1 portfolio provides economic and reliability benefits that exceed the cost of the investment and are broadly distributed across the MISO Midwest subregion

The timeline for approval of Tranche 1 is targeted for July 25

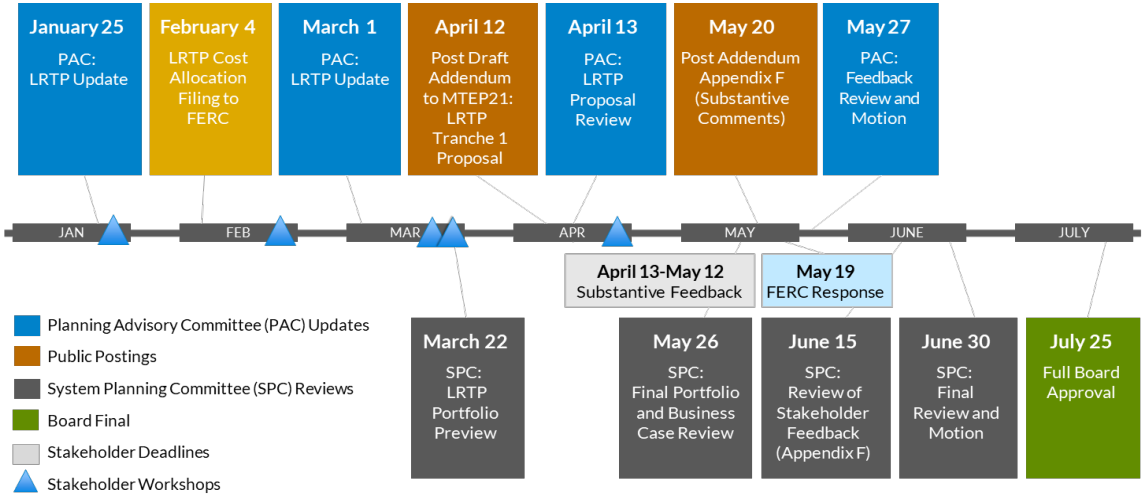


EXHIBIT MEC-25

RESERVED

U21859-MNSC-CE-0132
Page **1** of **1**

Question:

2. Refer to Connolly rebuttal, p. 5 lines 9-13:

a. Produce the agreement referenced and identify any provisions or modifications specific to data center or new "large load" customers.

b. Are the costs of a Rate GPD customer's service drop, meter, and transformer included in the referenced Contribution in Aid of Construction agreement? If yes, demonstrate that this is the case with supporting documentation or cost studies. If no, confirm if such costs are collected via the system access charge.

Response:

a. Attached is a copy of the Company's Contract for Electric Service for use with Allowance for Contribution in Aid of Construction.

b. No. The cost of the Customer's service drop, metering, and the customer's transformers are collected via the system access charge.

Witness: Laura M. Connolly
Date: July 18, 2025

CONTRACT FOR ELECTRIC SERVICE
FOR USE WITH ALLOWANCE FOR CONTRIBUTION
IN AID OF CONSTRUCTION

PART I

Effective Date of Agreement: _____
(Month/Day/Year)

Company:
CONSUMERS ENERGY COMPANY
a Michigan Corporation

ONE ENERGY PLAZA
JACKSON MI 49201-2357

Customer:

_____
(Legal Name)

_____
(Street Number)

_____
(City, State & Zip Code)

☐ Corporation ☐ Sole Proprietorship
☐ General Partnership ☐ Limited Partnership
☐ Limited Liability Company ☐ Education*
☐ Other (Specify) ☐ Government**

_____

	SERVICE CHARACTERISTICS
Service Location Name	Phase (60 Hertz)
Service Address	Voltage Level (CVL 1,2,3) Volts
Service Address City	Capacity Reserved (kW)
Service Address Township	Substation Ownership Credit ☐ Y ☐ N
Service Address County	Self-Generation Provision (SG) ☐ Y ☐ N
Customer Account Number	Minimum Monthly kWh: _____ Minimum Monthly On-Peak Demand kW: _____
Initial Term: _____ years(s) beginning with the Effective Date of Agreement stated above (includes ramp-up period).	Minimum Monthly Demand kW: _____ General Service Rate/Code: _____
See attached sheet for determination of Base Load (if applicable)	Final Month of Minimum Billing Effective Date for Monthly Minimum Billing to Begin

PART II, TERMS AND CONDITIONS, is attached hereto and is a part of this Agreement. CUSTOMER ACKNOWLEDGES HAVING READ SAID TERMS AND CONDITIONS.

CONSUMERS ENERGY COMPANY

By: _____
(Signature)

_____
(Print or Type Name)

Title: _____

Date: _____

_____
(Customer)

By: _____
(Signature)

_____
(Print or Type Name)

Title: _____

Date: _____

*Education Customers may also require resolution Form 1509.
**Government Customers may also require resolution Form 1502.

CONTRACT FOR ELECTRIC SERVICE
FOR USE WITH ALLOWANCE FOR CONTRIBUTION
IN AID OF CONSTRUCTION
TERMS AND CONDITIONS

PART II

1. The Company agrees to supply, and the Customer agrees to purchase hereunder, all of the electric energy for the operation of the Customer's Facility described in Part I, but not in excess of the capacity reserved amount identified in Part I. The Company will, at the written request of the Customer, made at least thirty (30) days in advance, permit an increase in such reserved capacity if the Company has power available. A location for the metering equipment, suitable to the Company, shall be provided by the Customer and adequate protection afforded to avoid damage thereto, tampering or interference with such metering equipment.

2. The electric energy to be supplied hereunder shall be alternating current and shall have the characteristics identified in Part I. Delivery shall be made at one mutually agreeable point upon the Customer's premises. It shall be metered by meters furnished, installed and maintained by the Company. A location for the metering equipment, suitable to the Company, shall be provided by the Customer and adequate protection afforded to avoid damage thereto, tampering or interference with such metering equipment. The Company shall make periodic tests of its meters and keep them within accepted standards of accuracy.

3. The Customer shall pay for such energy in accordance with Company's General Service Rate and applicable provisions identified in Part I, a copy of which is attached hereto and made a part hereof, and in accordance with such amendments thereto as may be filed with and approved by the Michigan Public Service Commission during the term of this Agreement.

4. **For Customers on the Energy Intensive Primary (EIP) Rate:** With Customer approval, the Company may equip Customer facility with the System, which includes site devices owned by the Company that can enable direct load management, power metering, data collection, near real-time data communication, and internet-based monitoring. There shall be no cost to the Customer associated with the System equipment or installation of the System equipment. The Company reserves the right to remove the System equipment if Customer elects to switch from the EIP rate to another primary rate.

5. If the Customer was provided an allowance for construction of facilities under the Contribution in Aid of Construction Allowance Schedule as provided for in the Company's Electric Rate Book, the Customer shall be required to make payment prior to construction as specified in a written facility agreement for the difference between the Allowance and the estimated cost of construction. The Customer shall be subject to Minimum Monthly Billing levels as specified in Part I and will continue for the balance of the Initial Term identified in Part I. The Monthly Minimum Billing will be effective beginning with the first day of the next full billing month following the date indicated on the 'Effective Date for Monthly Minimum Billing to Begin' as specified in Part I.

6. It is further agreed that:

   (a) Such service is for the sole use of the Customer, for the purpose aforesaid, and shall not be transmitted elsewhere, or shared or resold, or used as auxiliary or standby as to any other source of power supply, except as may be herein provided.

   (b) Such service shall be governed by the Company's Rate Book and such future revisions and amendments hereof, supplements thereto, or substitutions therefore as may be filed with and approved by the Michigan Public Service Commission during the term of

this Agreement. Unless otherwise specified, rate change becomes effective with the beginning of the Customer's next full month's billing cycle. A copy thereof will be furnished to the Customer upon request.

(c) Except as to the capacity and minimum charges payable by the Customer, prescribed in said rate, neither party shall be liable to the other for damages for any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's control, including any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party hereto; provided, however, that the Company's responsibility for interruptions in service, phase failure or reversal, or variations in the service characteristics shall be as provided in said Rate Book.

(d) This Agreement will become effective on the date identified in Part I and will extend for an initial term as stated in Part I and from month to month thereafter until terminated by mutual consent, or by either party giving the other at least sixty (60) days written notice of its desire to terminate the same at the expiration of any monthly period. If the Company does not receive notice prior to that time and has not issued a notice of termination on its own initiative, Customer's participating in the Energy Intensive Primary Rate shall be renewed for a minimum of the following 12-month period from the anniversary date of the Effective Date of Agreement in Part I. Notice of termination of the use of the Energy Intensive Primary Rate by the Customer to the Company or vice versa shall be mailed using the United States Post Office first-class mail. Notice to the Company for termination of the Agreement should be sent to Consumers Energy Company, Attention: Business Center Operations, 4000 Clay Avenue SW, Grand Rapids, MI 49548-3017.

(e) This Agreement inures to and binds the heirs, administrators, successors and assigns of the respective parties hereto. There are no understandings or agreements between them in relation to electric distribution service at the facility service location stated in Part I except as contained herein. This Agreement supersedes all previous representations, negotiations, understandings or agreements, either written or oral, between the parties hereto or their representatives pertaining to the subject matter hereof and constitutes the entire agreement of the parties. This agreement shall not be transferred by the Customer or otherwise alienated without the Company's written consent; any such attempted transfer without the Company's written consent shall be void.

(f) The Customer shall furnish, without cost to the Company, a suitable site on its premises at each plant location listed in Part I for the Company's transmission lines, substations, and/or distribution facilities as may be required to provide such service to said premises. If, during the term hereof, the Customer's use of said premises makes necessary the relocation of said facilities, from the site presently furnished, to another site on said premises, the Company shall relocate the same at the Customer's request, and the Customer shall reimburse the Company for the cost thereby incurred. The Company, its agents, employees, and authorized contractors shall have full right and authority of ingress and egress at all times on and across said premises of the Customer, for the purpose of constructing, operating, maintaining, replacing, repairing, moving and removing its said facilities. Said right of ingress and egress, however, shall not unreasonably interfere with the use of the Customer's said premises.

(g) This Agreement may be executed and delivered in counterparts, including by a facsimile or an electronic transmission thereof, each of which shall be deemed an original. Any document generated by the parties with respect to this Agreement, including this Agreement, may be imaged and stored electronically and

introduced as evidence in any proceeding as if original business records. Neither party will object to the admissibility of such images as evidence in any proceeding on account of having been stored electronically.

(h) During the Initial Term of this Agreement, as provided in Part I, Customer may request to change its electric rates in accordance with the Company's Rate Book. The Company may, in its sole discretion, approve such a request and reserves the right to amend the terms of the Agreement, including the Minimum Monthly Billing levels and Initial Term, to satisfy the obligations of the original Agreement between the parties.

7. Additional Terms:

U21859-MNSC-CE-0133
Page **1** of **1**

Question:

3. Refer to Connolly rebuttal, p. 7, lines 11-13:

a. Produce any documentation or analysis on which you rely for a 15-year contract term aligning with the terms of PPAs or other assets the Company will need to acquire to serve new load.

b. Refer also to Exhibit A-33 in Case No. U-21424, included as Attachment A to these discovery requests: provide the terms of each PPA in this exhibit.

c. Explain how the 15-year minimum contract term proposed by Consumers "aligns more closely" with the terms of the PPAs or other assets the Company will need to acquire to serve new load than does the 20-year minimum contract term proposed by MNSC witness Caroline Palmer.

Response:

a. The Company relied on existing terms of PPAs as a guide for expected future PPAs.

b. See attached.

c. The attachment shows terms that range from 1 to 35 years. While the Company has not determined whether it will serve this new load strictly with new PPAs, a 15-year agreement is in the middle of the range of existing contracts.

Witness: Laura M. Connolly
Date: July 18, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21424

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY AND CAPACITY CONTRACTS

Source: 12-2023 Bill

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
Line	**Energy & Capacity Company**	**Contract Capacity**	**Fuel Type**	**Variable Energy Rate**		**Capacity Rate**			**Administrative Charge**		**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Term (Years)**
				On-Peak	**Off-Peak**	**On-Peak**	**Off-Peak**	**$/ZRC-month**	**Rate**	**Special Notes**			
		MW		¢/kWh	¢/kWh	¢/kWh	¢/kWh		¢/kWh				
1	Ada Cogeneration Ltd Partnership	29.400	Nat Gas	Twelve-month rolling average cost of CE coal generation		4.024	3.822	N/A	0.100	Not to exceed $2,000/month	June 22, 1989 – U-8871/U-8833	1/4/26	35
2	Adrian Energy Associates	2.500	Landfill Gas	Twelve-month rolling average cost of CE coal generation		3.110	3.110	N/A	0.100	Not to exceed $2,000/month	March 31, 1993 – U-10127	12/12/29	35
3	Black River Power Limited Partnership	1.200	Hydro	6.768		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/39	35
4	Beaverton, City of	0.500	Hydro	6.768		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/39	20
5	C&C Energy, LLC - C&C 1 (f/k/a Gas Recovery Systems)	2.750	Landfill Gas	Twelve-month rolling average cost of CE coal generation		4.374	4.155	N/A	0.100	Not less than $442.12, Not to exceed $4,421.16	July 21, 1993 – U-10270	2/19/30	35
6	Cadillac Renewable Energy	34.000	Wood Waste	Twelve-month rolling average cost of CE coal generation		4.320	4.110	N/A	0.100	Not to exceed $2,000/month	June 22, 1989 – U-8871	7/15/28	35
7	Commonwealth Power Company – Irving	0.240	Hydro	Twelve-month rolling average cost of CE coal generation		4.034	3.832	N/A	0.100	Not to exceed $2,000/month	March 31, 1993 – U-10127	8/24/30	35
8	Commonwealth Power Company – LaBarge [1]	0.700	Hydro	5.400		N/A	N/A	8,768.50	N/A	Included in variable energy rate	September 26, 2019 - U-20604	5/31/39	20
9	Commonwealth Power Company – Middleville	0.200	Hydro	Twelve-month rolling average cost of CE coal generation		4.034	3.832	N/A	0.100	Not to exceed $2,000/month	March 31, 1993 – U-10127	12/31/30	35
10	Dow Silicones Corporation (DCC)	0.031	Solar	3.978		N/A	N/A	5,551.92	N/A	Included in variable energy rate	November 4, 2021 - U-20604	5/31/32	10
11	Elk Rapids Hydroelectric Power, LLC	0.600	Hydro	7.068		N/A	N/A	11,708.75	0.100	(Not less than $0.00, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/39	19.5
12	Energy Developments Byron Center, LLC (f/k/a Granger Electric of Byron Center)	3.000	Landfill Gas	6.396		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	February 4, 2021 - U-20604	5/31/39	20
13	Energy Developments Coopersville, LLC (f/k/a Granger Electric of Coopersville, LLC - Ottawa)	6.109	Landfill Gas	6.396		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	February 4, 2021 - U-20604	5/31/39	20
14	Energy Developments Grand Blanc, LLC (f/k/a Granger Electric Company – Grand Blanc)	3.812	Landfill Gas	6.396		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	February 4, 2021 - U-20604	5/31/39	20
15	Energy Developments Pinconning, LLC (f/k/a Granger Electric of Pinconning)	3.042	Landfill Gas	6.396		N/A	N/A	11,708.75	0.100	Not less than $0.00, Not to exceed $4,421.16	February 4, 2021 - U-20604	5/31/39	20
16	Genesee Power Station Limited Partnership	35.000	Wood Waste	Twelve-month rolling average cost of CE coal generation		4.650	4.420	N/A	0.100	(Not less than $200.00, Not to exceed $2,000.00	June 22, 1989 - U-8871	12/12/30	35
17	Good Fruit Storage	0.429	Solar	4.434	3.806	N/A	N/A	PRA	N/A	Included in variable energy rate	February 18, 2021 - U-20604	5/31/31	10
18	Grayling Generating Station Limited Partnership	36.170	Wood Waste	Twelve-month rolling average cost of CE coal generation		4.180	3.970	N/A	0.100	(Not less than $442.12, Not to exceed $4,421.16	June 22, 1989 - U-8871/U-10274	12/31/27	35
19	Grenfell Hydro, Inc	0.300	Hydro	5.405		N/A	N/A	8,768.50	N/A	Included in variable energy rate	November 14, 2019 - U-20604	5/31/39	20
20	Kent County	15.680	Solid Waste	6.315		N/A	N/A	11,708.75	0.100	(Not less than $442.12, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/39	X
21	Michiana Hydroelectric Co (Bellevue)	0.045	Hydro	7.068		N/A	N/A	11,708.75	0.100	(Not less than $442.12, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/39	20
22	Michigan Apple Packers Cooperative, Inc. (MAP)	0.150	Solar	3.6	3.058	N/A	N/A	PRA	N/A	Included in variable energy rate	January 20,2022 - U-20604	5/31/30	10
23	Michigan Power Limited Partnership	123.000	Nat Gas	Twelve-month rolling average cost of CE coal generation		3.880	3.686	N/A	0.100	Not to exceed $2,000/month	March 31, 1993 – U-10127	12/31/30	35
24	Michigan Wind I, LLC (f/k/a Noble Thumb Windpark, LLC.)	57.000	Wind	Monthly Energy Rate Letter		LMP	LMP	PRA	N/A	N/A	N/A	MTM	MTM
25	Midland Cogeneration Venture Limited Partnership	1240.000	Nat Gas	MCV Cost of Production		1.014	1.014	N/A	N/A	N/A	March 4, 2021 U-20896 June 10, 2008 - U-15320	5/31/30	35
26	South Christian High School (SCHS2021)	0.550	Solar	3.6	3.058	N/A	N/A	PRA	N/A	Included in variable energy rate	November 18, 2021 - U-20604	5/31/32	10

[1] LaBarge REC cost is recovered through RRP as shown on page 3

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: BAS
Exhibit No.: A-33 (BAS-1)
Page: 2 of 5
Witness: BASkowronski
Date: March 2025

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS

ENERGY AND CAPACITY CONTRACTS - CONTINUED

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
Line	Energy & Capacity Company	Contract Capacity	Fuel Type	Variable Energy Rate		Capacity Rate			Admistrative Charge	MPSC Order Approving Capacity Rate	Expected Termination Date	Term (Years)
				On-Peak	Off-Peak	On-Peak	Off-Peak	$/ZRC-month	Rate / Special Notes			
		MW		¢/kWh	¢/kWh	¢/kWh	¢/kWh		¢/kWh			
27	North American Natural Resources -Peoples	3.061	Landfill Gas	Twelve-month rolling average cost of CE coal generation		4.374	4.155	N/A	0.100 Not less than $442.12, Not to exceed $4,421.16	July 21, 1993 – U-10266	9/7/30	35
28	North American Natural Resources -Rathbun	1.600	Landfill Gas	5.153		N/A	N/A	8,768.50	N/A Included in variable energy rate	September 26, 2019 - U-20604	5/31/39	20
29	STS Hydropower Ltd – Cascade Hydro Plant	1.400	Hydro	5.335		N/A	N/A	8,768.50	N/A Included in variable energy rate	July 23, 2020 - U20833	5/31/39	20
30	STS Hydropower Ltd – Fallasburg Hydro Plant	0.850	Hydro	5.400		N/A	N/A	8,768.50	N/A Included in variable energy rate	July 23, 2020 - U20833	5/31/39	20
31	STS Hydropower Ltd – Morrow Hydro Plant	1.000	Hydro	3.978	3.978	N/A	N/A	N/A	N/A N/A	December 13, 1988 - U-8868	5/31/27	5
32	T.E.S. Filer City Station Limited Partnership	50.000	Coal	Twelve-month rolling average cost of CE coal generation		6.460	5.460	N/A	0.100 Not to exceed $2,000/month	February 19, 1987 - U-8562	6/16/25	35
33	Tower Kleber LP, Kleber Hydro	1.200	Hydro	6.865		N/A	N/A	PRA	0.100 (Not less than $0.00, Not to exceed $100,000.00.)	July 23, 2020 - U-20838	5/31/2039	19
34	Tower Kleber LP, Tower Hydro	0.560	Hydro	6.865		N/A	N/A	PRA	N/A Included in variable energy rate	July 23, 2020 - U-20838	5/31/2039	19
35	~~Viking Energy of Lincoln, LLC (Amendment Start Date January 1, 2019)~~	~~18~~ ~~Wood Waste~~		~~4.37~~		~~N/A~~	~~N/A~~	~~11708.75~~	~~0.1~~ ~~(Not less than $442.12, Not to exceed $4,421.16)~~	~~April 18, 2019 - U-20496~~	Decommissioned	~~N/A~~
36	Viking Energy of McBain, LLC (Amendment Start Date January 1, 2019)	18.000	Wood Waste	4.564		N/A	N/A	11,708.75	0.100 Not less than $442.12, Not to exceed $4,421.16	April 18, 2019 - U-20496	5/31/27	YTY
37	White's Bridge Hydro Company	0.817	Hydro	7.068		N/A	N/A	11,708.75	0.100 Not less than $0.00, Not to exceed $4,421.16	July 23, 2020 - U-20838	5/31/2039	20
38	WM Renewable Energy - Venice Park (f/k/a Bio Energy Partners)	1.500	Landfill Gas	Twelve-month rolling average cost of CE coal generation		4.190	3.980	N/A	0.100 Not less than $200.00, Not to exceed $2,000.00	June 22, 1989 – U-8871/U-10272	5/3/27	35
39	13 Mile Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
40	Bingham Solar	20.000	Solar	4.538		N/A	N/A	11,708.75	0.100 Not less than $0.00, Not to exceed $1,197.57	December 6, 2019 - U-20604	5/31/41	20
41	Captain Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
42	Coldwater Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
43	Geddes 1 Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
44	Interchange Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
45	Jack Francis Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
46	May Shannon Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
47	Stoneheart Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
48	Temperance Solar	20.000	Solar	4.538		N/A	N/A	11,708.75	0.100 Not to exceed $1,000/month	December 6, 2019 - U-20604	5/31/41	20
49	Workman Rd Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
50	Angola Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
51	Bullhead Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
52	Geddes 2 Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
53	Hazel Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
54	Hendershot Solar	2.000	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/41	20
55	Woodley Solar	0.821	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	December 6, 2019 - U-20604	5/31/42	20
56	STS Hydropower, LLC-Ada Hydro Plant	0.6	Hydro	DA_LMP		N/A	N/A	N/A	N/A Included in variable energy rate	August 22, 2024 - U-18425	5/31/25	1
57	Superior Sales Inc.	0.605	Solar	DA_LMP		N/A	N/A	N/A	N/A Included in variable energy rate	June 22, 2023 - U-20604	5/31/41	15
58	Freshwater Solar, LLC	300	Solar	5.990		N/A	N/A	N/A	N/A Included in variable energy rate	U-21090	5/31/42	20
59	Tibbits Energy Storage, LLC	100	Battery	1.454		N/A	N/A	N/A	N/A Included in variable energy rate	U-21090	5/31/45	20
60	Century Oaks Energy Storage, LLC	200	Battery	1.436		N/A	N/A	N/A	N/A Included in variable energy rate	U-21090	5/31/46	20
61	Voyager Energy Storage, LLC	100	Battery	1.454		N/A	N/A	N/A	N/A Included in variable energy rate	U-21090	5/31/47	20
62	Manitou Farms LLC	0.14976	Solar	DA_LMP		N/A	N/A	4,345.00	N/A Included in variable energy rate	U-20604	9/30/25	20
63	Macbeth Solar	20	Solar	4.538		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	9/31/39	1
64	Lyons Road	20	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	9/1/40	20
65	Letts Creek	15	Solar	4.415		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	12/31/41	20
66	Pullman	20	Solar	4.415		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	12/31/41	20
67	Cement City	20	Solar	4.415		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	12/31/41	20
68	Greenstone	20	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	5/5/43	20
69	Midcontinent	20	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	5/5/43	20
70	Blue Elk VII	12.331	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	5/5/43	20
71	Byrne Solar	5	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	5/1/43	20
72	Lightfoot Solar	10	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	6/1/43	20
73	Shipsterns Solar	20	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	7/1/43	20
74	Willford Solar	20	Solar	4.538		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	9/1/43	20
75	Calhoun Solar	140	Solar	3.747		N/A	N/A	5,551.92	N/A Included in variable energy rate	U-20165	11/30/46	20
76	Surbrook Solar	10	Solar	4.579		N/A	N/A	PRA	0.100 Included in variable energy rate	U-20604	10/15/40	20
77	Morey Road Solar	2	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	9/29/40	20
78	Surrey Road Solar	2	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	9/29/40	20
79	Lake City Solar	2	Solar	4.479		N/A	N/A	11,708.75	N/A Included in variable energy rate	U-20604	9/9/40	20
80	Blue Elk II Solar	20	Solar	4.238		N/A	N/A	3,208.33	N/A Included in variable energy rate	U-20604	9/15/43	20
81	River Fork Solar	100	Solar	3.932		N/A	N/A	N/A	N/A Included in variable energy rate	U-15805	3/31/44	20
82	Cereal City	100	Solar	3.526		N/A	N/A	4,308.33	N/A Included in variable energy rate	U-20165	5/31/48	24

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS

ENERGY-ONLY CONTRACTS

Line	Energy-Only Company	Contract Capacity	Fuel Type	Variable Energy Rate		Capacity Rate			Administrative Charge	MPSC Order Approving Capacity Rate	Expected Termination Date	Term (Years
				On-Peak	Off-Peak	On-Peak	Off-Peak	$/ZRC-month	Rate / Special Notes			
		MW		¢/kWh	¢/kWh	¢/kWh	¢/kWh		¢/kWh			
83	City of Grand Rapids-Waste Water Treatment Facility	2.822	Combined Heat & Power	MISO Real - Time LMP					0.100 Not less than $0.00, Not to exceed $100,000.00	N/A	MTM	N/A
84	City of Midland	N/A	Landfill Gas	90% of (Load Locational Marginal Price - $5/MWh)		-	-	-	0.100 Not less than $442.12, Not to exceed $4,421.16	N/A	MTM	N/A
85	Grand Valley State University	N/A	Fuel Cell	90% of the hourly top incremental cost		-	-	-	None	N/A	MTM	N/A
86	Mahle Engine Components USA, Inc.	N/A	Waste Energy	90% of (Load Locational Marginal Price - $5/MWh)		-	-	-	0.100 Not less than $442.12, Not to exceed $4,421.16	N/A	MTM	N/A
87	Michigan State University	N/A	Coal	Three-month rolling average top incremental cost		-	-	-	0.100 Not to exceed $200/month	N/A	YTY	N/A
88	Otsego Paper	20.000	Natural Gas	MISO Real - Time LMP		-	-	-	0.100 Not less than $0.00, Not to exceed $100,000.00	N/A	MTM	N/A
89	Western Michigan University	N/A	Nat Gas	Hourly top incremental cost		-	-	-	0.100 Min of $384/Mo, but not to exceed $3,845/Mo	N/A	MTM	N/A

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: BAS
Exhibit No.: A-33 (BAS-1)
Page: 3 of 5
Witness: BASkowronski
Date: March 2025

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
RENEWABLE RESOURCE PROGRAM CONTRACTS

Term (Years

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
Line	**Renewable Resource Company**	**Contract Capacity** MW	**Fuel Type**	**Variable Energy Rate**		**Renewable Rate**		**Admistrative Charge**		**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Term (Years)**
				On-Peak ¢/kWh	**Off-Peak** ¢/kWh	**On-Peak** ¢/kWh	**Off-Peak** ¢/kWh	**Rate** ¢/kWh	**Special Notes**			
109	C&C Energy, LLC (C&C Electric 2 Plant)	2.500	Landfill Gas	Average PSCR cost		3.722	3.722	0.100	Not less than $442.12, Not to exceed $4,421.16	October 18, 2005 - U-14626	2/27/27	20
110	Michigan Wind I, LLC (f/k/a Noble Thumb Windpark, LLC.)	12.000	Wind	Average PSCR cost		Redacted	Redacted	N/A	N/A	October 18, 2005 - U-14626	12/17/28	20
111	North American - Central, LLC (Pierson Station No. 1; f/k/a Venice Park)	3.200	Landfill Gas	Average PSCR cost		2.510	2.310	0.100	Not less than $442.12, Not to exceed $4,421.16	July 23, 2020 - U-15805	5/31/26	20

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Case No.: U-21424
Exhibit No.: A-33 (BAS-1)
Page: 4 of 5
Witness: BASkowronski
Date: March 2025

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
Line	**Public Act 295 Company**	**Contract Capacity** MW	**Fuel Type**	**Capacity Price** $/ZRC - Month	**Variable Energy Rate** **On-Peak** $/MWh	**Off-Peak** $/MWh	**REC Price** $/REC	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Term (Years)**
113	Apple Blossom Wind, LLC (f/k/a Geronimo Huron Wind, LLC)	100.000	Wind	Redacted	0.430		Redacted	November 19, 2015 - U-15805	5/31/33	15
114	Beebe Renewable Energy (f/k/a Blissfield)	81.600	Wind	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	July 27, 2010 - U-15805	12/17/32	20
115	Generate Fremont Digester, LLC (f/k/a Fremont Community Digester)	2.850	Gas Digester	$33,743.28	5.128		28.61	October 13, 2009 - U-15805	12/26/32	20
116	Harvest II Windfarm	59.400	Wind	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	July 27, 2010 - U-15805	10/31/32	20
117	DTE Garden Wind Farm, LLC	20.880	Wind/Solar	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	November 19, 2010 - U-15805	9/13/32	20
118	DTE Stoney Corners Wind Farm, LLC (Phase 2)	12.250	Wind	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	November 19, 2010 - U-15805	12/31/31	19
119	DTE Stoney Corners Wind Farm, LLC (Phase 3)	8.350	Wind	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	January 26, 2012 - U-15805	12/31/31	19
120	Michigan Wind 2	90.000	Wind	Redacted	2009 Renewable Energy Plan forecasted LMP		Redacted	July 27, 2010 - U-15805	12/31/31	19
121	North American-Central, LLC (Pierson Rd No. 2)	1.600	Landfill Gas	0.00	Day-Ahead LMP		32.03	July 23, 2020 - U-15805	12/15/30	20
122	WM Renewable Energy (Northern Oaks)	1.600	Landfill Gas	6,000.00	Day-Ahead LMP		10.88	October 13, 2009 - U-15805	11/10/30	20
123	WM Renewable Energy (Pine Tree Acres)	12.800	Landfill Gas	Redacted	2009 Renewable Energy Plan forecasted LMP		7.35	July 27, 2010 - U-15805	2/28/32	20

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS - EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION

Line	**Public Act 295 Company**	**Contract Capacity** MW	**Fuel Type**	**Capacity Price** $/ZRC - Month	**Variable Energy Rate** **On-Peak** $/MWh	**Off-Peak** $/MWh	**REC Price** $/REC	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Term (Years)**
124	Brook View Dairy	0.600	Gas Digester	0.00	RT_LMP		0.00	N/A	MTM	N/A
125	Scenic View Dairy	0.400	Gas Digester	0.00	RT_LMP		0.00	N/A	MTM	N/A

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Case No.: U-21424
Exhibit No.: A-33 (BAS-1)
Page: 5 of 5
Witness: BASkowronski
Date: March 2025

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS - EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - SOLAR

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line	**Public Act 295 Company**	**Contract Capacity** MW	**Fuel Type**	**Capacity Price** $/ZRC - Month	**Variable Energy** On-Peak $/MWh	Off-Peak $/MWh	**REC Price** $/REC	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**[2]
126	Experimental Advanced Renewable Program ("EARP") residential Phase 1	0.000	Solar	-	650		-	December 21, 2010 - U-15805	Varies
127	Experimental Advanced Renewable Program ("EARP") non- residential Phase 1	0.000	Solar	-	450		-	December 21, 2010 - U-15805	Varies
128	Experimental Advanced Renewable Program ("EARP") residential Phase 2	0.000	Solar	-	525		-	May 10, 2011 - U-15805	Varies
129	Experimental Advanced Renewable Program ("EARP") non-residential Phase 2	0.000	Solar	-	375		-	May 10, 2011 - U-15805	Varies
130	Experimental Advanced Renewable Program ("EARP") non-residential Phase 3	0.024	Solar	-	229 [1]		-	February 28, 2013 - U-15805	Varies
131	Experimental Advanced Renewable Program ("EARP") residential Phase 4	0.108	Solar	-	259 [1]		-	February 28, 2013 - U-15805	Varies
132	Experimental Advanced Renewable Program ("EARP") non-residential Phase 5	0.050	Solar	-	229 [1]		-	February 28, 2013 - U-15805	Varies
133	Experimental Advanced Renewable Program ("EARP") residential Phase 6	0.093	Solar	-	259 [1]		-	February 28, 2013 - U-15805	Varies
134	Experimental Advanced Renewable Program ("EARP") residential Phase 7	0.091	Solar	-	249 [1]		-	February 28, 2013 - U-15805	Varies
135	Experimental Advanced Renewable Program ("EARP") non-residential Phase 8	0.029	Solar	-	219 [1]		-	February 28, 2013 - U-15805	Varies
136	Experimental Advanced Renewable Program ("EARP") residential Phase 9	0.105	Solar	-	249 [1]		-	February 28, 2013 - U-15805	Varies
137	Experimental Advanced Renewable Program ("EARP") residential Phase 10	0.078	Solar	-	249 [1]		-	May 2, 2014 - U-15805	Varies
138	Experimental Advanced Renewable Program ("EARP") non-residential Phase 11	0.334	Solar	-	209 [1]		-	May 2, 2014 - U-15805	Varies
139	Experimental Advanced Renewable Program ("EARP") residential Phase 12	0.068	Solar	-	249 [1]		-	May 2, 2014 - U-15805	Varies
140	Experimental Advanced Renewable Program ("EARP") residential Phase 13	0.051	Solar	-	243 [1]		-	May 2, 2014 - U-15805	Varies
141	Experimental Advanced Renewable Program ("EARP") non-residential Phase 14	0.281	Solar	-	199 [1]		-	May 2, 2014 - U-15805	Varies
142	Experimental Advanced Renewable Program ("EARP") residential Phase 15	0.133	Solar	-	243 [1]		-	May 2, 2014 - U-15805	Varies
143	Experimental Advanced Renewable Program ("EARP") residential Phase 16	0.104	Solar	-	243 [1]		-	April 23, 2015 - U-15805	Varies
144	Experimental Advanced Renewable Program ("EARP") non-residential Phase 17	0.171	Solar	-	199 [1]		-	April 23, 2015 - U-15805	Varies
145	Experimental Advanced Renewable Program ("EARP") residential Phase 18	0.085	Solar	-	243 [1]		-	April 23, 2015 - U-15805	Varies
146	Experimental Advanced Renewable Program ("EARP") residential Phase 19	0.119	Solar	-	243 [1]		-	April 23, 2015 - U-15805	Varies
147	Experimental Advanced Renewable Program ("EARP") non-residential Phase 20	0.580	Solar	-	199 [1]		-	April 23, 2015 - U-15805	Varies
148	Experimental Advanced Renewable Program ("EARP") residential Phase 21	0.149	Solar	-	240 [1]		-	April 23, 2015 - U-15805	Varies
149	Experimental Advanced Renewable Program ("EARP") residential Phase 26	0.179	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
150	Experimental Advanced Renewable Program ("EARP") non-residential Phase 27	0.430	Solar	-	199 [1]		-	February 11, 2016 - U-15805	Varies
151	Experimental Advanced Renewable Program ("EARP") residential Phase 28	0.161	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
152	Experimental Advanced Renewable Program ("EARP") residential Phase 29	0.222	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
153	Experimental Advanced Renewable Program ("EARP") non-residential Phase 30	0.208	Solar	-	199 [1]		-	February 11, 2016 - U-15805	Varies
154	Experimental Advanced Renewable Program ("EARP") residential Phase 31	0.118	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
155	Experimental Advanced Renewable Program ("EARP") residential Phase 32	0.091	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
156	Experimental Advanced Renewable Program ("EARP") non-residential Phase 33	0.148	Solar	-	199 [1]		-	February 11, 2016 - U-15805	Varies
157	Experimental Advanced Renewable Program ("EARP") residential Phase 34	0.068	Solar	-	240 [1]		-	February 11, 2016 - U-15805	Varies
158	Experimental Advanced Renewable Program ("EARP") non-residential Phase 35	0.101	Solar	-	199 [1]		-	February 11, 2016 - U-15805	Varies

[1] Contracts awarded as part of EARP since Phase 3 inlcude a provision to pay an additional $1/MWh if certain conditions are satisfied. Most participants failed to satisfy the incentive provision.

[2] Contracts terminate no later than August 31, 2029

Question:

4. Refer to Connolly rebuttal, p. 11 lines 9-14:

a. When does the Company intend to file a rate proposal which will address cost allocation and rate design issues for new data center customers?

b. Describe in detail any terms, parameters, or provisions the Company plans to include in such a proposal. This question seeks the best information known or expected today.

c. Does the Company intend to apply the rates, terms, and provisions of a future rate proposal on cost allocation and rate design (as approved or modified by the Commission) to data center or new "large load" customers who have already executed an agreement under the terms Consumers has proposed in this case (as approved or modified by the Commission).

   i. If so, explain what steps the Company will take to ensure that data center or "large load" customers who execute an agreement under the terms approved in this case will be subject to the new rates, terms, and provisions approved in such future rate proposal.

   ii. If not, explain why not.

d. Refer to Connolly rebuttal, p. 11 lines 17-23: Respond to the questions regarding p. 11 lines 9-14 to the extent your answer is different with respect to the referenced "Large Load rate solution."

e. Until a future rate proposal of the type you describe is approved, how is or will Consumers ensure compliance with the requirement of Public Act 207 of 2024 that enterprise data centers not take electric service under a rate that causes residential customers to subsidize the costs incurred to provide electric service to the facility? Produce any documents you refer to or rely on for your answer.

f. Until a future rate proposal of the type you describe is approved, how is or will Consumers achieve compliance with the requirement of Public Act 207 of 2024 that any long-term generation contracts with enterprise data centers ensure no costs to serve the facility are passed onto other customers of the electric utility, cooperative electricity utility, or municipal utility? Produce any documents you refer to or rely on for your answer.

Response:

a. The Company has not yet determined when it will file a rate proposal to address cost allocation and rate design issues for new data center customers.

b. The Company has not yet determined this information.

c. Yes.

   i. The Company has included language in the draft Rate GPD Data Center Provision contract which states:

The Customer shall pay the applicable charges as provided in the Large General Service Primary Demand Rate GPD, which may be modified time to time by the MPSC, or other applicable rate as approved by the MPSC.

The Company believes this allows the authorization to move a customer that signs this contract to a future rate solution.

ii. NA

d. The Company still intends to file a future rate proposal to address large load additions as described in direct testimony, regardless of whether that proposal applies strictly to data center customers or all large load additions that don't qualify for the Large Economic Development Rate.

e. Through PA 286, the Commission has an obligation to ensure electric rates are set equal to the cost of providing serve to each customer class. If rates are set based on a Commission approved cost of service using Commission approved allocations, there will be no rate subsidization. Rates are based on approved cost of service methodologies.

f. See response to e.

Witness: Laura M. Connolly
Date: July 18, 2025

EXHIBIT MEC-29

RESERVED

Question:

6. Refer to Connolly rebuttal, p. 12 lines 6-23:

a. Describe the "robust intake process" referenced therein.

b. Explain the basis for your claim that such process has "limited the number of formal study requests."

c. Identify the number of "formal study requests" the Company has received from potential data center or "large load" customers since January 1, 2024.

d. Explain how the Company plans to recover administrative costs for project proposals without an administrative fee, including whether such recovery differs depending on whether the potential data center or other "large load" customer ends up taking service from the Company.

e. Produce any documentation or analysis for which you rely on the claim that creating a time tracking system would be unduly administratively burdensome.

Response:

a. Consumers Energy initiated a data center intake process in February 2025. Prior to a data center prospect entering the process, expectations are communicated to the data center prospect sharing the overall process and timing expectations for development of an energy solution. If they elect to proceed, upfront the Company requires a point of entry form including specific energy details for a single site. Once submitted, Consumers Energy will determine whether all required fields have been completed to initiate developing a formal energy solution. If complete, the development of an energy solution through a project proposal is the next step. Once an energy solution is developed via a project proposal, and provided to the prospect, there is a six-month expiration of the provided energy solution. These requirements within the intake form have narrowed the progression of the project requests as it requires a prospect to understand the scope of their project and site being considered.

b. As of February 2025, the Company has had 50+ project inquiries, the formalized process has generated 8 formal study requests at this time. Previously, we could have been asked to support all inquiries, with limited information being provided.

c. There are a total of 15 data center project proposal requests received since January 1, 2024.

d. We will follow standard response protocol and provide a project proposal once the point of entry form and required information is deemed complete by Consumers Energy. Recovery is not differentiated, and the administrative costs or providing project proposals will be recovered via ordinary ratemaking cost allocation processes. Requiring the necessary information needed to proceed with a project proposal has reduced the project proposal requests.

e. Due to the cross functional nature of supporting large load requests, there are numerous departments and staff resources required. A standardized system, protocols and training would need to be developed to ensure all areas of the organization are consistent and complying with tracking time

required to support the project proposal development. Further, we believe the intake process has ensured inquiries move forward are legitimate and anticipate minimal volume due to requirements that are required to confirm project validity before we initiate a formal study for data center prospects.

Witness: Laura M. Connolly
Date: July 18, 2025

Question:

7. Refer to Connolly rebuttal, p. 13 lines 5-14: Based on existing plans, rates, and tariffs – as well as the Company's proposals in this case – how will Consumers ensure compliance with the requirement of Public Act 207 of 2024 that enterprise data centers will have procured or will procure clean energy equivalent to 90% of their facilities' forecasted electricity usage on an annual basis? Produce any documents you refer to or rely on for your answer.

Response:

As stated in rebuttal, the Company will ensure compliance through the cases specifically designed to address these issues, including the Renewable Energy Plan and the Integrated Resource Planning cases.

Witness: Laura M. Connolly
Date: July 18, 2025

EXHIBIT MEC-32

RESERVED

U21859-MNSC-CE-0019
Page **1** of **1**

Question:

3. Identify and produce any contracts, tariff provisions, or other mechanisms regarding the provision of service to data centers that Consumers has developed or is in the process of developing.

Response:

The Company has prepared the attached draft contract for Rate GPD with the data center provision. The proposed tariff provisions were provided as Exhibit A-1 (LMC-1).

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

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

DATA CENTER PROVISION

CONTRACT FOR ELECTRIC SERVICE
PART I

Parties to Contract	
Company Consumers Energy Company a Michigan Corporation One Energy Plaza Jackson, MI 49201-2357	**Customer**
Customer Facility	
Service Location Name	**Service Characteristics**
Service Location	**Billing Address**
Service Address City	**Customer Account Number** To be assigned at permanent meter set
Service Address County	**Meter Numbers** To be assigned at permanent meter set
Maximum Demand: **On-Peak Billing Demand:** **Monthly Minimum Charge**: Customer Charge, MPSC-approved surcharges and Minimum Billing Demand charge. **Substation Ownership Credit**: Y ☐ or N ☐ **Interruptible Service Provision**: Y ☐ or N ☐	**Term**: 15 Years, beginning on Effective Date.
Additional Pages of Agreement	
The Large General Service Primary Demand Rate GPD – Data Center Provision Contract for Electric Service includes this Part I and the attached Part II (Terms and Conditions, including Exhibits), which is incorporated herein by reference and expressly made a part hereof, together being this "Agreement."	
Execution of Agreement	
Company and Customer hereby enter into this Agreement, as evidenced by the signatures of their authorized representatives below. The Effective Date for service under this Agreement to begin is [_____]	

CONSUMERS ENERGY COMPANY	[CUSTOMER]
Garrick J. Rochow	[Name]
President and Chief Executive Officer	[Title]
Consumers Energy Company	[Company]
Date: _____	Date: _____

TERMS AND CONDITIONS

PART II

1. This Agreement is made under Company's Large General Service Primary Demand Rate GPD ("Rate GPD") a copy of which is attached hereto as Exhibit A and made a part hereof. The Agreement is subject to the applicable rates and other tariff provisions approved by the Michigan Public Service Commission ("MPSC"), which may be changed from time to time.

2. The Customer acknowledges and agrees that, as of the Effective Date of this Agreement: (i) the Customer will be a full service electric customer which will take service at the Company's Primary Voltage levels; (ii) in order to receive electric service from the Company, Customer has agreed to a minimum Term of 15 years for this Agreement; and (iii) the Customer will meet a monthly Minimum Billing Demand for the Term this Agreement, which is defined as eighty percent (80%) of the On Peak Billing Demand specified in section 2(a) of this Agreement and eighty percent (80%) of the Maximum Demand specified in section 2(a) of the Agreement. The Customer further acknowledges and agrees to the following requirements:

   (a) On Peak Billing Demand and Maximum Demand Requirements are set based on the ramp up schedule below:

Effective Date	On Peak Billing Demand Requirement	Maximum Demand Requirement
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW
X/X/20XX	X MW	X MW

   (b) In the event that the Customer's monthly On Peak Billing Demand and/or Maximum Demand is below the Minimum Billing Demand, the Customer shall pay the Company an amount equal to the difference between the actual service taken and the Minimum Billing Demand, calculated at the applicable rates.

   (c) In the event Customer's On Peak Billing Demand or Maximum Demand exceeds the amounts specified in Part I of this Agreement, the Company may require amendment to Part I of this Agreement to reflect the actual service taken. The Minimum Billing Demand will be adjusted upward to reflect any increases to the On Peak Billing Demand or Maximum Demand specified in Part I of this Agreement.

   (d) Customer Exit Fee: In the event Customer ceases taking power supply service from the

Company at the Customer Facility identified in Part I of this Agreement during the Term of this Agreement, the Company shall be entitled to recover from Customer an Exit Fee. The Exit Fee shall be calculated by multiplying the Minimum Billing Demand by the remaining months left in the Term, based the date on when Customer ceases taking power supply service from the Company. The Company may, at its sole discretion, reduce the Exit Fee if it determines that the loss of the Customer's load will not harm the Company or its other customers.

3. Customer shall provide the Company with financial security or other collateral from the Customer, the suitability of which will be determined by the Company in its sole discretion, in amounts up to the projected cost of providing service to the Customer for the Term of this Agreement, as specified in Exhibit B to this Agreement. This requirement shall not be interpreted to limit the Company's authority to require other financial security requirements from the Customer.

4. Customer shall pay an upfront administrative fee, not to exceed one hundred thousand dollars ($100,000) per project proposal, to cover the costs associated with preparing the proposals. This fee shall be charged directly to the entity requesting the proposal and is non-refundable.

5. The Company agrees to supply, and the Customer agrees to purchase hereunder, all of the electric energy for the operation of the Customer's Facility described in Part I.

6. The electric energy to be supplied hereunder shall be alternating current and shall have the characteristics identified in Part I. Delivery shall be made at one mutually agreeable point upon the Customer's premises. It shall be metered by meters furnished, installed and maintained by the Company. A location for the metering equipment, suitable to the Company, shall be provided by the Customer and adequate protection afforded to avoid damage thereto, tampering or interference with such metering equipment. The Company shall make periodic tests of its meters and keep them within accepted standards of accuracy.

7. The Customer shall pay the applicable charges as provided in the Large General Service Primary Demand Rate GPD, which may be modified time to time by the MPSC, or other applicable rate as approved by the MPSC.

8. It is further agreed that:

   (a) Such service is for the sole use of the Customer and shall not be transmitted elsewhere, or shared or resold, or used as auxiliary or standby as to any other source of power supply, except as may be herein provided.

   (b) The Company reserves the right, at its sole discretion, to allow a one-time adjustment to the Contract Capacity. This adjustment must be mutually agreed upon by both the Company and the Customer and will be documented in an amendment to the existing contract. If the Customer's usage exceeds the Contracted Capacity by 1,000 kW or more, the Company shall have the right to amend the contract to reflect the increased usage. The Customer will be responsible for any additional costs incurred due to this increase in capacity. Should additional capacity be unavailable, the Customer shall be required to reduce its usage to the Contract Capacity. Failing to comply with this

requirement, the Company reserves the right to suspend service.

(c) Such service shall be governed by the Company's Rate Book for Electric Service ("Rate Book") and such future revisions and amendments hereof, supplements thereto, or substitutions therefore as may be filed with and approved by the MPSC during the Term of this Agreement. A copy thereof will be furnished to the Customer upon request.

(d) Except as to the Monthly Minimum Charge payable by the Customer, neither party shall be liable to the other for damages for any act, omission or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or by any other cause or causes beyond such party's control, including any curtailment of service by the Company, or order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or by the making of necessary repairs upon the property or equipment of either party hereto; provided, however, that the Company's responsibility for interruptions in service, phase failure or reversal, or variations in the service characteristics shall be as provided in the Company's Rate Book.

(e) This Agreement will become Effective on the date identified in Part I and will extend for a Term as stated in Part I and from month to month thereafter until terminated by mutual consent, or by either party giving the other at least twelve (12) months written notice of its desire to terminate the same at the expiration of any monthly period after the initial Term. Notwithstanding the foregoing, the Company may, in its sole discretion, terminate this Agreement on ninety (90) days' written notice if the MPSC issues an order which disallows or otherwise impairs the Company's cost recovery associated with this Agreement. Notice of termination of this Agreement after the initial Term by the Customer to the Company or vice versa shall be provided in writing.

(f) This Agreement inures to and binds the heirs, administrators, successors and assigns of the respective parties hereto. There are no understandings or agreements between them in relation to electric service at the facility service location stated in Part I except as set forth herein. This Agreement supersedes all previous representations, negotiations, understandings or agreements, either written or oral, between the parties hereto or their representatives pertaining to the subject matter hereof and constitutes the entire agreement of the parties. This Agreement shall not be transferred by the Customer or otherwise alienated without the Company's written consent; any such attempted transfer without the Company's written consent shall be void.

(g) The Customer shall furnish, without cost to the Company, a suitable site on its premises location listed in Part I for the Company's distribution lines, substations, and/or facilities as may be required to provide such service to said premises. If, during the Term hereof, the Customer's use of said premises makes necessary the relocation of said facilities, from the site presently furnished, to another site on said premises, the Company shall relocate the same at the Customer's request, and the Customer shall

reimburse the Company for the cost thereby incurred. The Company, its agents, employees, and authorized contractors shall have full right and authority of ingress and egress at all times on and across said premises of the Customer, for the purpose of constructing, operating, maintaining, replacing, repairing, moving and removing its said facilities. Said right of ingress and egress, however, shall not unreasonably interfere with the Customer's use of said premises.

(h) This Agreement may be executed and delivered in counterparts, including by an electronic transmission thereof, each of which shall be deemed an original. Any document generated by the parties with respect to this Agreement, including this Agreement, may be imaged and stored electronically and introduced as evidence in any proceeding as if original business records. Neither party will object to the admissibility of such images as evidence in any proceeding on account of having been stored electronically.

9. Severability. In the event that any provision or portion of this Agreement shall be determined to be invalid or unenforceable for any reason, the remaining provisions of this Agreement shall be unaffected thereby and shall remain in full force and effect. In the event that the Term, Minimum Billing Demand or Customer Exit Fee provisions of this Agreement are determined to be invalid or unenforceable, the parties will use good faith efforts to promptly amend this Agreement to ensure appropriate cost recovery for the Company if: (i) there is any shortfall in the Customer's usage below the Minimum Billing Demand threshold and (ii) Customer ceases taking power supply service from the Company at the Customer Facility identified in Part I of this Agreement during the Term of the Agreement.

EXHIBIT MEC-34

RESERVED

EXHIBIT MEC-35

RESERVED

EXHIBIT MEC-36

RESERVED

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Retail Sales Forecast
2024-2045 Forecasted
(MWh)

Case No.: U-21816
Exhibit No.: A-6(EMB-1)
Page: 1 of 1
Witness: EMBreuring
Date: November 2024

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	Year	Residential	Commercial	Industrial	Industrial LED [1]	Streetlighting	Inter-departmental	**Total Retail [2]**	Non-Jurisdictional [3]	Jurisdictional	Jurisdictional %
1	2024	12,413,092	11,259,942	8,793,065	11,016	99,473	32,141	**32,608,729**	16,508	32,592,221	99.95%
2	2025	12,603,436	11,363,123	9,260,264	256,639	105,200	30,608	**33,619,270**	15,133	33,604,137	99.95%
3	2026	12,624,190	11,333,182	9,074,454	1,678,600	104,002	30,608	**34,845,036**	14,834	34,830,202	99.96%
4	2027	12,800,055	11,322,093	8,953,405	3,156,893	102,814	30,608	**36,365,868**	14,536	36,351,332	99.96%
5	2028	12,891,333	11,237,727	8,819,720	3,792,124	101,642	30,608	**36,873,154**	14,245	36,858,909	99.96%
6	2029	13,165,682	11,316,288	8,756,507	5,340,566	101,642	30,608	**38,711,293**	14,245	38,697,048	99.96%
7	2030	13,655,282	11,086,649	8,764,293	7,490,327	101,642	30,608	**41,128,801**	14,245	41,114,556	99.97%
8	2031	14,166,097	11,106,008	8,666,310	8,661,083	101,642	30,608	**42,731,748**	14,245	42,717,503	99.97%
9	2032	14,527,118	11,619,735	8,865,209	8,691,153	101,642	30,608	**43,835,465**	14,245	43,821,220	99.97%
10	2033	14,973,837	11,879,333	8,892,477	8,667,407	101,642	30,608	**44,545,304**	14,245	44,531,059	99.97%
11	2034	15,354,723	12,335,533	9,047,552	8,667,407	101,642	30,608	**45,537,465**	14,245	45,523,220	99.97%
12	2035	15,605,629	12,689,152	9,139,062	8,667,407	101,642	30,608	**46,233,500**	14,245	46,219,255	99.97%
13	2036	15,823,567	13,010,451	9,215,611	8,691,153	101,642	30,608	**46,873,032**	14,245	46,858,787	99.97%
14	2037	15,991,006	13,248,857	9,248,628	8,667,407	101,642	30,608	**47,288,148**	14,245	47,273,903	99.97%
15	2038	16,087,164	13,441,212	9,273,595	8,667,407	101,642	30,608	**47,601,628**	14,245	47,587,383	99.97%
16	2039	16,165,274	13,519,566	9,274,606	8,667,407	101,642	30,608	**47,759,103**	14,245	47,744,858	99.97%
17	2040	16,189,072	13,561,530	9,271,370	8,691,153	101,642	30,608	**47,845,375**	14,245	47,831,130	99.97%
18	2041	16,083,736	13,516,646	9,261,347	8,667,407	101,642	30,608	**47,661,386**	14,245	47,647,141	99.97%
19	2042	15,943,443	13,449,137	9,246,093	8,667,407	101,642	30,608	**47,438,330**	14,245	47,424,085	99.97%
20	2043	15,796,224	13,379,198	9,229,791	8,667,407	101,642	30,608	**47,204,870**	14,245	47,190,625	99.97%
21	2044	15,646,784	13,307,516	9,211,894	8,691,153	101,642	30,608	**46,989,597**	14,245	46,975,352	99.97%
22	2045	15,497,734	13,233,937	9,190,885	8,667,407	101,642	30,608	**46,722,213**	14,245	46,707,968	99.97%

Notes:

[1] "LED" = Large Economic Development customers (Industrial Class)

[2] "Total Retail" = Total deliveries less Wholesale and ROA

[3] "Non-Juris" = Grand Rapids Streetlighting

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

1. Refer to the Rebuttal Testimony of Nicholas M. Revere, p. 9:

   a. Identify the issues advanced by intervenors in this case that you believe should be addressed in Consumers' IRP case instead and explain in detail why.

Answer:

As stated by Staff witness Revere on page 9 of rebuttal: "The integrated resource planning (IRP), renewable energy planning (REP), and capacity demonstration processes set up by the Commission consistent with the prevailing statutes are the appropriate place to consider the resources and plans that are most appropriate to ensure compliance with those statutes." There are aspects of intervenor proposals that should be addressed in each of these types of cases; it is not as simple as stating a single type of case a proposal should be considered in.

The proposal by CEO witness Saddique discussed on page 7 of Staff witness Revere's rebuttal "to 'require potential data center customers to develop clean energy sourcing plans as part of their applications for electric service' the information within which would be used by the Company to, in part, evaluate how the load would impact its RES compliance" would have aspects that should be considered in IRP cases (e.g. appropriate generation mix to serve the Company's load consistent with the prevailing statute), REP cases (how/how much to serve the Company's load with renewables consistent with the prevailing statute), capacity demonstration cases (ensuring the Company covers its capacity requirements

consistent with the prevailing statute), and potentially aspects appropriate to consider in other cases, such as including "a clear pathway for prospective data center customers to utilize Consumers' Voluntary Large Customer Renewable Energy Program (or a similar program) to access new, incremental, time-matched, deliverable clean energy to help serve their new load requirement," (CEO witness Saddique direct testimony, p. 16) which has aspects that, to the extent not already possible, should be considered in a VGP case.

The proposal by MEIU witness Albers discussed on page 7 of Staff witness Revere's rebuttal for "a 'clean transition tariff' that would 'provide for the customer's ability to choose the type of resources desired, such as generation, transmission, or distribution resources that are sourced or supported via utility procurements, bilateral or trilateral contracting, behind-the-meter and/or front-of-meter collocation arrangements'" also has aspects that would need to be covered in each of the cases as discussed for CEO witness Saddique's proposal, and additionally the proposals discussed on pages 7 and 8 of Staff witness Revere's testimony "to 'make incremental monetary contributions to existing EWR, DR, VPP, and demand flexibility programs,' 'implementation of dynamic transformer rating', 'deployment of grid enhancing technologies' as alternatives'" would require additional support and explanation that should be considered in rate cases, distribution plan cases, EWR cases, DR cases, and potentially other cases. The proposal by MEIU witness Albers discussed on page 8 of Staff witness Revere's rebuttal to duplicate an existing VGP program outside of the VGP process including

"that the Company will issue requests for proposals (RFPs) for generation specific to serving particular customers' needs" again contemplates issues similar to those discussed above with regard to CEO witness Saddique, including the appropriate cases aspects would need to be considered in.

The proposal by MNSC witness Jester discussed on page 8 of Staff witness Revere's rebuttal to "provide the options necessary to meet the tax exemption requirements through 'bespoke resources that reasonably match the data center's load' including that 'Consumers Energy provide at least 60% renewable energy to data center customers as part of any bespoke resource portfolio'" also has aspects that should be considered in the cases as listed in response to CEO Saddique's proposal above, as does how AG witness Deupree "recommends 'a requirement that the Company enter into a contract with the customer for the procurement of at least 60 percent of its load requirement from renewable sources located within MISO Zone 7" as discussed on page 8 of Staff witness Revere's rebuttal.

Further explanation of Staff's reasoning as to why it takes these positions in the instant case is stated on page 9 of Staff witness Revere's rebuttal: "Considering such issues outside of the context of those established processes risks failing to consider everything appropriate in determining how best to comply with those statutes.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

b. Describe in detail how the issues you claim should be addressed in the IRP case instead of this case can be addressed prior to Consumers making contractual commitments or investments for the first group of data center or new large load customers.

Answer:

As it is uncertain when or whether the Company will make contractual commitments or investments (it is worth noting that these two timeframes are unlikely to be the same), there are a number of ways those issues could be addressed in the appropriate cases prior to same. It may be that no contractual commitments or investments are made prior to the regularly scheduled cadence of such cases. The Company could agree or be required to file such cases earlier than currently assumed in order to ensure the issues are properly contemplated in the appropriate cases. The Commission may be able to issue orders on its own motion to require the filing of cases in certain instances. In addition, Staff is not convinced that the record in the instant case supports the necessity of these issues being completely determined prior to the Company actions contemplated; again, there are processes to ensure compliance with relevant statutes through cases that allow for all relevant issues to be dealt with, and whether or not things change in the time between those cases is part of the normal course of business.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

c. Identify the issues advanced by intervenors in this case that you believe should be addressed in Consumers' REP case instead and explain in detail why.

Answer:

Please see response to 1.a.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

d. Explain how the issues you claim should be addressed in the REP case instead of this case can be addressed prior to Consumers making contractual commitments or investments for the first group of data center or new large load customers.

Answer:

Please see response to 1.b.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

e. Identify the issues advanced by intervenors in this case that you believe should be addressed in Consumers' capacity demonstration case instead and explain why.

Answer:

Please see response to 1.a.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

f. Explain how the issues you claim should be addressed in the capacity demonstration case instead of this case can be addressed prior to Consumers making contractual commitments or investments for the first group of data center or new large load customers.

Answer:

Please see response to 1.b.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

2. Refer to Revere rebuttal, p. 9 lines 13-20:

   a. In what case should actions required of Consumers to ensure compliance with the provisions of the statute related to data center tax exemptions be addressed, and when would such a case occur?

Objection and Answer:

Staff objects to this question because it calls for speculation. While maintaining its objection, Staff responds as follows:

Staff declines to speculate in what case the Commission or the Company would deem it appropriate to address the issue fully, but offers the following response. Such provisions could be addressed in a number of ways: the Company could file an ex parte case with a proposal; the Company could include a proposal in a future rate case filing; the Commission could require the Company to either of those things as a result of the instant case; the Commission could issue an order on its own motion requiring either of the previous options or another not envisioned by Staff. In addition, Staff is not convinced by the record in the instant case that action under the statute is necessary, particularly in the instant case. In any event, a separate case will allow for the development of a more robust record on the issue than exists in the instant case to ensure appropriate tariff provisions are approved as necessary.

Respondent: Nicholas M. Revere 9
Objection: Staff Counsel

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

b. In what case should tariff alterations necessary as a result of the data center tax exemption provisions be addressed, and when would such a case occur?

Answer:

Please see response to 2.a. In addition, such a case could occur at any time the Commission or the Company found it appropriate or necessary.

Respondent: Nicholas M. Revere 10

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

c. What should be done with respect to new enterprise data centers and the tax exemption statute during the time until such a case or case is resolved?

Objection and Answer:

Staff objects to this question because it calls for speculation.

Staff declines to speculate on what actions the Company, the Commission, other intervenors, or Staff should or may take with regard to the issue.

Respondent: Nicholas M. Revere 11
Objection: Staff Counsel

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

3. Refer to Revere rebuttal, p. 10 lines 11-18:

   a. Explain why treating uniquely large loads of the scale contemplated in this case as if they are being served individually is unjustified and identify what standard or authority you rely on in offering that opinion.

Answer:

Staff is not taking the position that treating "uniquely large loads of the scale contemplated" in the instant case is necessarily unjustified in all instances, only that it is unsupported in the instant case, though Staff can understand how the wording of Staff witness Revere's rebuttal may have lead to the misunderstanding. (Staff witness Revere rebuttal, pp. 10-12.) Further, Staff is of the opinion that it is more appropriate to consider such issues in the context of the appropriate cases as discussed in the response to 1.a., as well as that certain allocation and direct assignment issues are more appropriately contemplated in rate cases, where such issues can be fully examined in the appropriate context. Any eventual cost allocations or rate recovery approved by the Commission (and Staff recommendations regarding the same) in the future may or may not align with traditional or historical allocation/recovery.

While the only standard or authority relied on at present for forming the opinion is that of the extensive knowledge and experience of Staff, including Staff

witness Revere, Staff notes that no greater standard or authority was presented in support of the idea.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

b. Explain why treating uniquely large loads of the scale contemplated in this case as if they are being served individually is inappropriate and identify what standard or authority you rely on in offering that opinion.

Answer:

Please see response to 3.a.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

c. Explain why treating uniquely large loads of the scale contemplated in this case as if they are being served individually is discriminatory and identify what standard or authority you rely on in offering that opinion.

Answer:

Staff did not claim that such treatment is discriminatory, only that it "may be discriminatory as such options are not available to other customers" as Staff witness Revere states on page 10 of rebuttal.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

Question:

d. Refer also to your rebuttal, p. 11 lines 13-16: Do you agree or disagree that adding new loads of the scale contemplated in this case and serving them with more expensive new generating plans is likely to raise costs or rates for other customers in the absence of direct assignment of those costs? Explain your answer in detail.

i. If you agree that it is likely, what if anything should be done about it, in your opinion?

Answer:

As stated by Staff witness Revere, that costs or rates would rise for customers if a new, more expensive plant is built by the Company "would be true whether the plants were built to serve new or existing load." As discussed throughout Staff witness Revere's rebuttal, as well as these responses, what "should be done about it" is fully examining all aspects of the related issues through the well-established processes and cases set up by statute and the Commission.

MPSC Staff's Answer to MNSC's First Discovery Request
MPSC Case No. U-21859
July 18, 2025

4. Refer to Revere rebuttal, p. 11 lines 2-5.

   a. Describe in detail the scenario or scenarios in which generation required to serve the load contemplated under the data centers or new large load provision in addition to that already planned for could be less expensive than what would have otherwise been built.

   b. Identify any examples you are aware of in which the scenario you describe or a scenario analogous to what you describe has occurred or is expected to occur.

Answer:

a. One possible scenario is accomplishing economies of scale as the required generation amount is higher, resulting in a larger plant being built without a proportional increase in cost, lowering the cost per kW or kWh.

b. Staff is unaware of an example of such a scenario as of the time of this response.

EXHIBIT MEC-42

RESERVED

MPSC STAFF INITIAL COMMENTS

September 27, 2024

Pursuant to the Orders dated May 23, 2024 and July 2, 2024 in Case No. U-21637

In its order dated May 23, 2024 in Case No. U-21637, the Commission stated:

> *The Commission welcomes the opportunity to investigate how the experience of litigating and deciding these cases can be improved, streamlined, or simplified. At the same time, the Commission continues to seek ways to enhance the opportunity for any interested person to participate in these matters and to improve the ability of the ratepaying public to understand the implications of these cases.*
>
> *Thus, the Commission seeks comment on a variety of process issues. The Commission begins this investigation by inviting comment on the following issues:*
>
> *1. Does the current 10-month statutory timeframe serve the best interests of utility customers? If not, what is the appropriate timeframe?*
>
> *2. Should there be a minimum amount of time between rate case filings (longer than the current 12-month requirement) in order to allow evaluation of the actions directed in the utility's previous rate case order? If so, what should the minimum time be and how would it be implemented? Should there be additional measures requiring rate cases to be spaced further apart?*
>
> *3. Should utilities file multi-year rate plans instead of making annual rate case filings? If so, how would this be implemented?*
>
> *4. Are there issues that would benefit from being heard and decided in separate proceedings? If so, what are the issues? Would legislation be required in order to move these issues out of rate cases or to address and resolve the issues identified for separate proceedings? How would this affect the holistic review of rates?*
>
> *5. Does the fully projected test year serve the best interests of utility customers? If not, how should it be modified or replaced, and how would any changes be implemented?*
>
> *6. How can equity and environmental justice issues be better integrated into rate cases?*
>
> *7. Does the current rate case process provide sufficient opportunities for participation by interested persons? If not, how could the process be improved to lower barriers and promote greater participation and transparency? Are there potential guidelines that could be shared with intervenors that would help to manage the case record?*
>
> *8. Are there administrative changes to the contested case process that could result in additional improvements such as shorter notice requirements or page limits? Other additions to the RCFR?*
>
> *9. What other improvements to the rate case process should be considered by the Commission or other entities?*

In response to the Commission's order, Staff offers the following comments. Staff notes that these Staff comments are responsive comments that can be primarily characterized as idea-based and/or solution-focused comments. Unless otherwise noted, Staff is not making any recommendations in these

comments, and Staff is not advocating for any particular idea or outcome except where explicitly noted. With that as the backdrop, Staff offers the following comments:

1. Does the current 10-month statutory timeframe serve the best interests of utility customers? If not, what is the appropriate timeframe?

Staff Comment 1a: Staff believes that any rate case process which allows for a full and complete evidentiary record and due process serves the best interest of utility customers. Staff believes the current 10-month statutory timeframe does not impair the Commission's ability to hear and decide each rate case issue in a just and reasonable manner, presuming a concise yet sufficient evidentiary record. As the Commission order that initiated this proceeding referenced, rate cases have undergone an extraordinary expansion in size over the past seven years. The increased number of issues and increased number of intervenors have made the 10-month timeframe more challenging in recent years and put a strain on the resources of the Commission and its Staff. As discussed further in these comments, this expansion may warrant consideration of additional deliberation time within the existing 10-month timeframe or perhaps additional time to issue a rate case order.

Staff Comment 1b: The 10-month statutory timeframe in Michigan is not the longest or the shortest when compared to other states. Some states do not have statutory timing limits (13% of states), while others have limits of less than 7 months (13%), a few states have limits greater than 12 months (6%), while the majority of states must process rate cases within 7-12 month limits (68%).[1] That said, there is very little schedule flexibility within the current construct and very real consequences for the failing to issue an order within 10-months.[2] Staff notes that it has refined and improved its audit/review and case administration processes over the years as circumstances regarding rate cases have changed, and generally speaking, Staff believes it is well equipped to handle annual rate case applications (as well as serve as the Commission's technical wing to effectuate its orders) within the existing statutory construct.

2. Should there be a minimum amount of time between rate case filings (longer than the current 12-month requirement) in order to allow evaluation of the actions directed in the utility's previous rate case order? If so, what should the minimum time be and how would it be implemented? Should there be additional measures requiring rate cases to be spaced further apart?

Staff Comment 2a: Staff believes the current structure strikes a reasonable balance of interests. Whether it's in the single-year rate setting construct established at present, or in hypothetical multi-year rate setting construct, the ability to adjust rates annually is reasonable. In the non-regulated space, businesses are largely free to adjust prices as often as needed as business, economic, and financial

[1] Source: Regulatory Research Associates, a group within S&P Global Commodity Insights. Data compiled as of February 28, 2024.
[2] MCL460.6a(5) states that if the commission fails to reach a final decision with respect to a completed petition or application to increase or decrease utility rates within the 10-month period following the filing of the completed petition or application, the petition or application is considered approved.

conditions change. Many of these conditions impact utilities as well (such as inflation, interest rates, etc.) and utilities also experience periods of significant capital investment (such as at present).

Staff Comment 2b: If the Commission would like to consider or investigate methods to increase the spacing/timeframe between rate adjustments (between rate cases), then such methods could include:

1. Filing Spacing. MCL460.6a(1) states that *"A utility shall coordinate with the commission staff in advance of filing its general rate case application under this section to avoid resource challenges with applications being filed at the same time as applications filed under this section by other utilities".* At present, this is accomplished through the Filing Announcement approved in U-18238 which deals with Rate Case Filing Requirements. The Filing Announcement is required 60 days prior to when a utility rate case application is filed. In addition, MCL 460.6a(6) provides that a utility may file an application for an increase in rates every 12 months, and MCL 460.6a(1) allows the Commission to require the two largest electric IOUs to space their rate case filings at least 21 days apart.

   Instead of being applicable to just the two largest electric IOUs, a revised/new law could apply to all electric, gas and steam utilities. A revised/new law could also reconsider the 21-day spacing, perhaps providing additional Commission flexibility above and beyond the current 21 days. For example, at present, if 4 utilities were to file on or around March 1 (and 2 of those were the largest electric IOUs) then even the existing 21 day spacing wouldn't achieve meaningful differentiation as there would still be 4 new rate cases within a 21-day period. The disadvantages of a reactionary spacing law (such as exists today) versus a structural/embedded solution is that a utility company may get shifted further than it would prefer due to factors outside of its own control (such as other utilities filing at the same time) and the Commission must take action / issue orders in order to achieve reasonable spacing.

2. Filing Windows. Rate case filing windows offer a structural solution as opposed to a reactionary solution to the concept of utility rate case spacing. In a filing window structure, each utility is assigned a period of time by which it could file a rate case during a given year. This type of window could be one single month, a two-month period, two separate one-month periods at different times throughout the year, etc. The advantage of a filing window structure is that it eliminates the chance of having too many cases filed within a narrow window of time which stresses available staff and resources. Filing windows do not hinder the ability of a utility to file an annual rate case, but do provide structural spacing and certainty for resources and workload timing. Certain considerations for timing of such windows would be appropriate, considerations that Staff did not attempt to fully explore for purposes of these comments. For example, filing windows that allow for gas companies to have new rates in place by November/December (the start of the heating season) and electric companies to have new rates in place by May/June (the start of the cooling season). Another example would be to pair the utilities which are historically the most likely to have contested orders with those that are the least likely, that way if both file in the same window the chances of multiple contested orders is reduced. Below is a hypothetical, illustrative-only depiction of what a Filing Window structure could look like. Again, Staff is

not recommending or advocating for any particular details outlined in this example – it is for illustration only. The example below shows a two-month consecutive filing window for each utility. However, as mentioned above, other constructs are also feasible.

Utility	Filing Window	New Rates by
DTE Gas (1), UMERC Gas (2)	Jan 2024	Oct 2024
DTE Gas (2), NSP-Gas(1)	Feb 2024	Nov 2024
NSP-Gas (2), I&M (1)	March 2024	Dec 2024
I&M (2), Detroit Thermal (1)	April 2024	Jan 2025
CE Elec (1), Detroit Thermal (2)	May 2024	Feb 2025
CE Elec (2), NSP Elec (1)	June 2024	March 2025
UPPCo (1), NSP Elec (2)	July 2024	April 2025
UPPCo (2), Alpena (1)	Aug 2024	May 2025
DTE Elec (1), UMERC Elec (1), Alpena (2)	Sept 2024	June 2025
DTE Elec (2), UMERC Elec (2), MGU (1)	Oct 2024	July 2025
CE Gas (1), SEMCo (1), MGU (2)	Nov 2024	Aug 2025
CE Gas (2), SEMCo (2), UMERC Gas (1)	Dec 2024	Sept 2025

3. Adjustment Clauses. An adjustment clause is designed to allow a utility to recover the impact of an underlying component (cost item, capital item, revenue item, etc.) on a current basis, without any negative effect on the bottom line and without the expense and delay that accompanies a rate case filing. Adjustment clauses ranging from full revenue requirement mechanisms to more narrowly defined adjustment clauses such as inflation, capital spending, pension, uncollectibles, sales, ROE, etc., are often used to reduce the frequency of rate case filings. Adjustment clauses and trackers can be useful ratemaking tools if they structured to be in the best interest of customers. For example, the PSCR and GCR mechanisms are examples where a cost has been shifted out of a rate case to a separate proceeding for recovery after a full and complete review. This provides for full recovery of all reasonable costs for fuel and purchased power and eliminates the need to file a rate case if the main driver is a change in fuel costs. Staff notes that the types of costs recovered through the PSCR and GCR process have historically been volatile and tied to global markets, such as oil, where it is difficult to predict the costs or a cost that is outside of the utility's direct ability to control, such as transmission. The structure of the PSCR and GCR processes does not reduce the review process or volume of work, but rather, it shifts it out of a rate case proceeding into a separate case. The Commission has also utilized trackers to emphasize and focus utility spending to achieve improvements in various areas. Staff does not advocate for or against adjustment clauses to improve the rate case process; however, any consideration of adjustment clauses should be structured in a way that provides benefits for customers.

   Other adjustment clauses have been previously adopted within a rate case proceeding as trackers, such as for a single cost item or a specific utility account, where in most instances

the focus has been only on the amount spent. While a tracker that is structured in this manner is not as time consuming to review, Staff cautions that this type of tracker does not allow for a full and complete review of the costs being tracked as well as any offsetting changes in other costs. In addition, it may lead to single issue ratemaking and can limit a utility's ability to manage its costs in the most efficient way for customers. Adjustment clauses and trackers may or may not reduce the frequency of rate cases. The advantages and disadvantages of automatic adjustment clauses and non-automatic adjustment clauses have been well documented in proceedings over the years and therefore Staff will limit its comments here.

3. Should utilities file multi-year rate plans instead of making annual rate case filings? If so, how would this be implemented?

Staff Comment 3a: In its most basic structure, Staff believes that multi-year rate plans are comparable to projected test periods in that the further out into the future one attempts to set rates then the more likely those rates are to be exposed to forecast/projection error. Staff has refined and improved its audit/review process over the years as circumstances regarding rate cases have changed and, generally speaking, Staff believes that the ability to file annual rate cases does not cause a problem for Staff from a workload/resources perspective.

Staff Comment 3b: While use of multi-year rate plans would almost certainly reduce the number of rate case filings over time, the trade-off for such a reduction in rate case filings may introduce an avoidable and undesirable amount of forecast error and uncertainty in the process. The particular details of a multi-year rate plan framework would also be relevant when trying to assess the viability and effectiveness of multi-year rate plans. For example, would it be a utility's choice to seek a multi-year plan, or mandatory? Would there be a limit to how far out the multi-year window extends (2 years, 3 years, 5 years, etc.)? Would there be an off switch or off ramps for the Commission to direct utilities to discontinue seeking multi-years plans if preferred? Staff believes that any consideration or investigation into the concept or implementation of multi-year rate plans would warrant very thorough analysis beyond this comment docket.

Staff Comment 3c: Staff is sensitive to the bottlenecks that the current annual rate case filing construct can, and sometimes does, create. Most notably, Staff is very sensitive to the deliberation related bottleneck concerns the Commission has discussed in the past. Specifically, in its order dated March 4, 2021 in dual captioned Case Nos. U-20940 and U-20963, the Commission stated (at page 2): "*Given that rate cases are the most difficult and complex cases that the Commission hears, the applicant utility's chosen timing takes on the utmost importance. Once the applicant utility has made its filing, the Commission must consider, well in advance, how it will manage the time required to give each case the attention and consideration that is the right of the applicant, of all of the parties, and of every ratepayer. A rate case does not become ripe for the Commission's review until the filing of replies to exceptions to the Administrative Law Judge's Proposal for Decision (PFD). The Commission's most active involvement comes at the tail end of the case when the parties' obligations have ceased."* And at page 4, the Commission discussed the timing of holidays with respect to deliberations by stating: *"Case No. U-20963 will become ripe in mid-November and the final decision must be reached not later than December 31,*

2021, thus encompassing Thanksgiving, and a number of other holidays within the period of time allotted to the Commission for deliberations and preparation of the final decision."

Given this sensitivity, Staff offers the following ideas to help mitigate the deliberation related bottlenecks. Staff also offers additional ideas to mitigate this bottleneck in response to Question 4.

1. Rates Effective 2 weeks after Order. There have been a few rate case orders (U-18370, U-21297, U-21389) where the Commission directed that rates become effective 2 weeks after the order date. Of note, when the Commission has opted to do this the decision was made during the pendency of each case. The timing of this decision is meaningfully different than if the Commission were to make this 2-week effective date the standard procedure used in all rate cases. At present, a utility may choose to file a rate case on March 1 with the expectation of a final order making new rates effective January 1. In filing on March 1, the critical time of the deliberation period includes the Christmas and New Years holidays. Not ideal, as the Commission has mentioned. However, the timing dynamic would change if the 2-week rate effective date were the standard procedure and known by all utilities and parties up front as a normal course of business. A utility company that wants new rates effective January 1 would simply file its rate case around February 14 (2 weeks earlier). In doing so, the deliberation window shifts earlier in December and excludes the Christmas and New Years holidays. This would effectively preserve much needed deliberation time, while at the same time providing new rates effective January 1.[3] In addition, this idea would also help to reduce the amount of volume in rate cases as this concept would not need to be recommended and rebutted as was done in the recent cases.

   This process could be implemented with tariff sheets attached to the decision order, or with direction from the Commission for the tariff sheets to be filed to the docket by a certain date without them attached to the decision order. Not attaching tariff sheets to the decision order actually preserves the most deliberation time (as much as a couple weeks), as the time allotted internally for technical staff to create the tariff sheets could be repurposed as additional deliberation time.

   The Commission could also consider directing the utilities to file the tariff sheets instead of Staff, after consultation with Staff of course. In either scenario, the cost of service and rate design would still need to be completed over the back end of December, but as Staff has alluded to already, this is manageable. As long as the utilities know to expect this approach as standard procedure, each utility could still receive new rates when it expects them by shifting its filing date accordingly.

2. Permanent change to the number of days allotted to the Commission deliberation window. At present, schedule guidance is reflected in the rate case filing requirements pursuant to Case No. U-18238. If the Commission believes that it does not have enough time to deliberate based on the current Commission guidance then the Commission can simply

[3] This deliberation window shift would benefit the Commission office by mitigating the holiday/timing bottlenecks specific to deliberation timing. Technical staff may still have to work on final tariff completion during that period just as it does now, thus at worst there is no harm to technical staff.

change it, for any reason at all or for no reason at all. The Commission has the full authority, at present without new law, to modify the RCFR and create a default schedule that provides it with more deliberation time. Of course, adding time to any particular stage of the rate case process will result in an equivalent reduction of time in a different stage(s) of the process.

3. On a non-permanent, ad-hoc basis, the Commission can set the set the schedule for any rate case filing that causes the Commission to be concerned with size of the deliberation window and/or the timing of where the deliberation period falls on the calendar. The Commission has the full authority, at present without new law, to create any schedule it desires. This of course could mean tweaks to the 10-month schedule, but since the 10-month deadline is a ceiling, this could also include utilizing shorter schedules such as 8-months, 9-months, etc. – which could be useful in mitigating bottlenecks caused by multiple cases being filed on or around the same date. And of course, adding time to any particular stage of the rate case process will result in an equivalent reduction of time in a different stage(s) of the process.

4. The Commission does not set a complete schedule, but instead files a letter to docket advising the ALJ to set a schedule the allots the Commission with "x" number of days for deliberation in a particular case if it feels it needs more time that outlined in the RCFR. The importance of the public facing letter is that it would allow all parties to know as well, which would allow all parties to build that new information into their proposed schedules used during offline discussions that take place during the weeks leading up to the prehearing. If only the ALJ is aware, then all of those offline discussions would simply be lost time due to lack of shared information. In the alternative, instead of a letter to the docket, the Commission could inform the ALJ and the Staff Case Coordinator directly, giving explicit authority to the Case Coordinator to share this information with the other parties.

5. The Commission could utilize the full amount of time allowed by law to maximize the number of deliberation days. For example, the Commission order that initiated this proceeding referenced the most recent, large DTE Electric case, Case No. U-21297. The order in that case was issued approximately 9 days prior to the statutory deadline. Similarly, the most recent rate case order for the I&M rate case in July 2024 was issued 12 days prior to the statutory deadline. For reference, there have been 10 contested rate cases for DTE and Consumers Energy since 2017 (under the 10-month law), and the Commission has issued orders in those cases an average of 5.2 days prior to the statutory deadline (three of those being issued nine days or more prior to the statutory deadline). By comparison, for the final 11 contested cases (the non-read-the-record cases) under the 12-month statutory deadline, the Commission issued orders in those cases an average of 5.8 days prior to the statutory deadline. In order to achieve full maximization of the time allotted and allowed by law, thus gaining the most deliberation time possible within the current construct, the Commission could consider aligning its Commission meetings to coincide with the statutory deadlines or call a special meeting to the same end. This can also be done at present, without needing new law.

4. Are there issues that would benefit from being heard and decided in separate proceedings? If so, what are the issues? Would legislation be required in order to move these issues out of rate cases or to address and resolve the issues identified for separate proceedings? How would this affect the holistic review of rates?

Staff Comment 4a: Separate proceedings often have the benefit of time, or specifically the lack of a statutory deadline to analyze and rule on the issues. That said, the more issues that are separated out from the rate case proceeding the more difficult it becomes to review multiple factors holistically at the same time in the same proceeding when setting rates. Regardless of what issues are handled within a rate case, or alternately outside of a rate case, Staff believes the critical element is the nature of how that information (and more importantly any Commission decisions) flow into a rate case. For example, it is possible to review an issue in a separate proceeding but if that proceeding simply results in a "punt" to a rate case then those issues are effectively being relitigated and a new record is being created in a rate case. This is very similar to the issue simply showing up for the first time in the rate case. By comparison, it is also possible to review an issue in a separate proceeding and the subsequent order/outcome/findings are simply reflected in the next rate case to reflect the rate impacts of the prior case/order (without re-review or relitigating). If addressing issues in separate proceedings, with the idea of reducing rate case record volume, then clear orders and findings would be necessary so that any information that flows into the rate case from those other proceedings are simply a "check the box" type rate case effort to ensure the utility reflected the information correctly. And this type of structure already exists at present, with depreciation rates and the PSCR base.

For example, the review in determining the appropriateness of new proposed depreciation rates can be completed in a stand-alone case or a general rate case, with the latter having less time for review. If done in a stand-alone case, the new approved depreciation rates typically are applied in the next subsequent rate case. In either occurrence, the new rates are applied to the corresponding plant balances to determine the appropriate amount of depreciation expense to be included in base rates. But, when new rates have already been determined appropriate and ordered by the Commission in a stand-alone case, parties in a general rate case only need to verify the rates being applied match those approved in the stand-alone depreciation rate order. This greatly simplifies the general rate case, and thus the stand-alone depreciation rate case is the much-preferred depreciation proceeding by Staff. Typically, depreciation rate case orders require the company file a new case every five years (or sooner at the utility's discretion) so that depreciation rates are kept up-to-date.

Another example of simplifying the rate case can be found by reviewing how PSCR costs are applied to rates in Michigan. Fuel and purchased power expenses have a base set in general rate cases, but have plans, reconciliations, and factors that are all handled outside the rate case. This is largely because this expense has a tracking mechanism by which reasonable and prudent costs are simply passed-through to customers as a separate line item on the utility bill (after review and approval in a stand-alone case).

Staff Comment 4b: Separate the Revenue Requirement/Deficiency (Rev-Def) and the Cost of Service / Rate Design (COS/RD) into Separate Proceedings. The rate case is a huge undertaking, and one way to reduce the size, scope and volume while still resulting in reasonable rates would be to separate the two primary components of the rate case into two separate, stand-alone proceedings. When a utility files a rate case, it is seeking incremental revenue because it has a revenue deficiency. At the time of the filing, the utility already has a Commission authorized COS/RD model. Separation of the Rev-Def and COS/RD

would still allow a utility to file a rate case annually and receive incremental rate relief on an annual basis. This process would also reduce the number of issues under consideration, thus reducing the volume of the case and the number of issues to discuss during deliberations (and for issuing a PFD). As for separating the rev-def from the COS/RD, there are several different ways that could be handled. Some examples:

> Example 1: A utility would file a revenue deficiency case that does not include a concurrent change to its currently authorized COS/RD model. The rev-def case is processed, and the Commission issues a Rev-Def order. The outcome of the Rev-Def order is run through the currently authorized COS/RD model to produce new rates.[4] At the time the Rev-Def order is issued, that order would trigger the next COS/RD proceeding to begin immediately following the Rev-Def order. The two cases would always go hand in hand, in other words, any time there is a Rev-Def order then there would always be a subsequent COS/RD proceeding each time. Once the COS/RD proceeding is completed, that revenue requirement from the Rev-Def proceeding is run through the newly approved COS/RD model to produce updated, revenue neutral rates that are effective on a go-forward basis only.
>
> Example 2: A utility would file a revenue deficiency case that does not include a concurrent change to its currently authorized COS/RD model. The rev-def case is processed, and the Commission issues a Rev-Def order. The outcome of the Rev-Def order is run through the currently authorized COS/RD model to produce new rates. At the time the Rev-Def order is issued, that order would trigger the next COS/RD proceeding to begin *IF AND ONLY IF the most recently approved COS/RD model is more than "x" months/years old.* It would seem reasonable that if a COS/RD order had just been issued within 1-3-6-9-12 etc. months (some fixed amount of time) prior to the Rev-Def order that the Rev-Def would not trigger a subsequent COS/RD case.
>
> Example 3: COS/RD cases occur on a standard cadence without respect to when a Rev-Def case is filed or Rev-Def order is issued. In theory, you could do an annual, biennial, triennial, etc. COS/RD proceeding and then any time a Rev-Def order is issued the revenue deficiency is simply run through the most recently approved COS/RD model from this cadence. In this example, there would likely be times that a Rev-Def case is filed and overlaps the timing of a cadence-filed COS/RD case (similar to what happens with depreciation cases at present).

Each of these examples would reduce the volume of record evidence compared to present, reduce the number of issues, and streamline the rate setting process.

Staff Comment 4c: Discrete Issue Separation. The Commission could consider separate contested proceedings related to certain facets of the rate case. A considerable amount of record evidence is provided regarding electric distribution, gas distribution and gas transmission in rate cases. For

[4] This process would still require the Staff to ensure the new revenue deficiency is properly run through the currently authorized CS/RD model to ensure rate accuracy (similar to what Staff does at the conclusion of deliberations). In order ensure this is done properly, Staff runs a COSS and does rate design/tariffs, etc. This process takes approximately 2-3 weeks. In other words, in order to provide the rev-def/COS/RD separation impact as discussed in Comment 4b, Staff would have to do a couple weeks of work that it currently does not have to do in the current construct of a single case.

example, contested electric distribution plan proceedings where investment levels (and maybe even expenses such as tree trimming) are considered/pre-approved in a stand-alone contested proceeding and then the ratemaking impacts are effectuated in the next rate case. Infrastructure Recovery Mechanism (IRM) implications could follow this procedural separation as well. ROE could also be separated out. Another functional area of separation could include issues that directly impact the revenue requirement, cost of service, rate design versus those issues/items that do not.

If the goal is to reduce the volume of issues and evidence in a rate case, clear decisions in the separated proceedings would be critical to such a reduction. As previously outlined in Comment 4a, this type of separation already exists for certain items. Those decisions simply flow into the next rate case where parties would "check the box" to make sure the cost recovery and ratemaking impact is reflected properly.

5. Does the fully projected test year serve the best interests of utility customers? If not, how should it be modified or replaced, and how would any changes be implemented?

Staff Comment 5a: The prevailing goal is just and reasonable rates, and Staff believes that just and reasonable rates can be achieved through both projected test periods and/or the use of historical periods to set rates. In either scenario, the most important element is the quality of the information available (data/information/recommendations provided by the utility and intervening parties), and then what is done with that information (decisions/orders of the Commission). When viewed through the lens of a customer (as the question poses), the risk of projection error in setting rates is reduced with an increased reliance on historical information. In theory, a rate setting process (backed by law) that relies fully on historical data would eliminate forecast error and also, very likely, reduce the voluminous nature of the record (as this would eliminate all of the support/evidence related to projections). The disadvantage of increased reliance on historical data is regulatory leg, which by and large impacts the utility and not the customer.

Staff Comment 5b: Historical Test Period or Historical Data Reliance. While the law allows a utility to use projected costs and revenues to develop its rate request, the law does not require the Commission to use projected costs and revenues to set rates. If the law doesn't change, a utility can still file a case with projected costs and revenues. Specifically, MCL 460.6a states that *"A utility may use projected costs and revenues for a future consecutive 12-month period in developing its requested rates and charges."* As such, even if the Commission were to establish rates based exclusively on historical data or historical test periods (without a change to current law), it would be unlikely that the record evidence would be meaningfully reduced because the utility can still (and likely would) file its case using projected periods because the present law allows for that. This means that Staff and the parties would still have to audit and create record evidence pertaining to the projections just as happens today. However, if the law were to change and no longer allow for projected costs and revenues, then the singular use of historical data/periods would likely reduce the size of the record in rate cases.

6. How can equity and environmental justice issues be better integrated into rate cases?

Staff Comment 6a:

Under the current legal construct which guides the Commission's decision making in rate cases, there is not a clear opportunity to identify and explicitly address equity. Equity and environmental justice have yet to be defined in relation to the setting of rates and the applicable legal requirements. While the Commission has been given authority to consider environmental justice in the integrated resource planning process in Public Act 235 of 2023, the Commission has not been given this direct authority in the setting of utility rates.

In addition, PA 231 of 2023 (MCL 460.6m(12)) broadens the scope of the Utility Customer Participation Board's granting authority such that the "board shall encourage grant making to nonprofits representing environmental justice communities and communities with the highest energy burdens." However, the Commission is not provided explicit authority to consider environmental justice communities or disparate impacts on identified communities in its decision-making process in rate cases.

The Commission has been proactive and stated that "*the work necessary to define equity and related terms as well as establish metrics for the energy infrastructure would be appropriate in the EAAC and its subcommittees.*" (Case No. U-20836, order dated November 18, 2022, p463). Currently the Energy Affordability and Accessibility Collaborative (EAAC) created under Case No. U-20757 is developing recommended definitions for energy equity and related terms. This work will further the understanding of what energy equity is and provide a foundation for exploring how equity can be considered in analysis of utility investments in the absence of direct authority for the Commission to consider it in rate setting.

The concepts of equity and environmental justice are being raised more often in other types of cases before the Commission, such as distribution plan and energy waste reduction plan filings, which can ultimately inform and impact rate case proceedings. Staff suggests that any consideration of equity and environmental justice in Commission proceedings be approached with consistency to the extent possible.

In the absence of explicit authority to consider equity and environmental justice in rate case proceedings and with the ongoing work in the Energy Affordability and Accessibility Collaborative, and related foundational work occurring at the Commission, it is premature to provide definitive recommendations on integrating equity and environmental justice into its proceedings. Staff notes that the Commission could consider opening a proceeding to more fully explore opportunities for consideration of equity related issues in Commission proceedings including rate cases. The proceeding could examine appropriate reporting metrics, frequencies, and formats to provide better insight into issues of equity and environmental justice, could help to streamline the Commission's efforts in this area, and could reduce duplicative work on the part of both Staff and interested parties.

7. Does the current rate case process provide sufficient opportunities for participation by interested persons? If not, how could the process be improved to lower barriers and promote greater participation and transparency? Are there potential guidelines that could be shared with intervenors that would help to manage the case record?

As a threshold matter, the rate case process is complex. It is governed by rules of legal practice, procedure, and evidence. The issues addressed in these cases are equally complex, addressing issues of utility operations, engineering, physics, economics, accounting, financial accounting, and utility law. Decisions in rate cases must be based on the law (Constitutional, statutory, and case law) and the record of evidence developed through the case process. Commission rate case orders are legal documents addressing these technical and legal issues. The issues addressed and processes through which decisions are rendered can be challenging for a nonexpert to navigate. The reality of the rate case process is that legal representation by attorneys versed in regulatory and utility law is incredibly important for successful participation.

Staff Comment 7a: Participation

There has been an increasing interest in participation before the Commission in rate cases. Over the last several years, the number of parties and issues raised in rate cases has dramatically increased. The order that invited these comments provides an example. DTE Electric's 2023 electric rate case, Case No. U-21297, involved 69 parties, 85 witnesses, and 4,227 pages of testimony.[5] By comparison, DTE Electric's 2016 electric rate case, Case No. U-18014, involved 31 parties, 45 witnesses, and 2,031 pages of testimony. As the order indicated, this trend of expanding case record volume is reflected in virtually every rate case filed since 2016. Said another way, rate case participation is at an all-time high.

This expanded participation includes several types of organizations that represent a diverse array of interests. In the 2016 DTE Electric rate case, interveners were primarily environmental organizations or business interests. While representation of these interest has expanded, the 2023 DTE Electric rate case included organizations that represent "frontline communities" in DTE's service territory and that focus, in large part, on issues of affordability and social and environmental justice. Organizations with similar interests have also begun to intervene in Consumers Energy cases.

Additionally, the legislature has taken steps to provide additional resources for those wishing to intervene in Commission cases. Recognizing the importance of legal representation and participation by experts in these cases, the 2023 energy laws included additional funding for the Utility Consumer Participation Board to grant out for intervention, and added *"The board shall encourage grant making to nonprofits representing environmental justice communities and communities with the highest energy burdens"* See *MCL 460.6m(12).* This increased funding increases opportunities to expand the organizations able to participate in rate cases before the Commission.

To the extent that individual ratepayers are interested in participating in rate cases however, the opportunities are more limited. First, an individual wishing to intervene would need to meet the requirements for intervention. Additionally, each party to a case is required and expected to comply with the rules of practice, procedure, and evidence which would be difficult for an unrepresented individual. The issues in cases are complex which would be difficult to address for a lay person.

[5] Number of parties as found on the Parties list on the e-docket.

Furthermore, UCPB funding is not available to individuals seeking to represent their individual interest. Simply put, even if an individual ratepayer were able to meet the requirements for intervention, such participation may be cost prohibitive and, without an attorney and access to other expertise, exceptionally challenging.

While the nature of the rate case process and the complexity of the issues under consideration do not lend well to intervention by individual ratepayers, it should be noted that non-parties are not without recourse for making their opinions on a utility rate request known. Every regular Commission meeting includes an opportunity for public comment and members of the public routinely use this time to share their opinions on any number of matters pending before the Commission. Additionally, comment during these meetings is taken from individuals participating both in person as well as through the Microsoft Teams meeting platform. Written public comment may also be submitted through the "Submit Comment" feature on the Commission's e-dockets webpage as well as through e-mail. These comments are included in the comments section of the individual case page and may be reviewed by the Commission, Staff, parties in the cases, and members of the public.

Taken as a whole, there appears to be sufficient opportunity for interested organizations to intervene in rate cases and for individual ratepayers to share their comments.

Staff Comment 7b: Transparency

Merriam Webster defines "transparency" as "the quality or state of being transparent." Transparent has two definitions which could apply in this instance. First is "characterized by visibility or accessibility of information especially concerning business practices." The second definition which could apply is "readily understood."

Rate cases are a matter of public record and nearly all documents are available for review and public consumption in real time (posted within one business day, often within a couple of hours) on the e-dockets system. In addition, prior to filing a rate case, utilities are required to provide the Commission with a Filing Announcement at least 60 days prior to the rate case filing. This is a public document and any person interested in knowing when a utility intends to file rate cases has access to this information through the Commission's e-dockets system. Utilities also include a summary of their rate case requests which provides an overview of the factors influencing the utility's request. This document is helpful for anyone wishing to understand the reason for the request without needing to review hundreds of pages of testimony and exhibits.

While case documents are easily accessible via the Commission's e-dockets system, the nature of these cases and the format of many of the documents (for instance, the question-and-answer style of testimony) can make them difficult to follow or understand for members of the public. Additionally, Proposals for Decisions and Commission Orders can also be difficult to understand as they often refer to issues raised in testimony and decisions will often adopt a particular witness' or party's position. To know what has been decided then, one must go back to the referenced testimony or other filing and determine what position was taken.

With this in mind, to the extent that "transparency" references access to information, the Commission is exceedingly transparent in its decisions. Not only is the evidence upon which the Commission makes its decisions available to the public, Commission orders detail the Commission's reasoning for each decision

that goes into determining a utility rate. However, to the extent that transparency in this instance means that decisions are readily understandable, the nature of the process, complexity of the issues, and volume of information make achieving this level of transparency challenging. Changes to the process that would improve this type of transparency can certainly be envisioned but would likely be detrimental to decision-making. For instance, the Commission could encourage that legal and utility operations terms of art be eliminated, but this would likely only serve to confuse the issues and complicate decision-making as less precise, unclear terms would replace very specific, technical ones.

To address this transparency challenge, the Commission could consider developing rate case fact sheets that could be issued following an order. Such fact sheets could explain, in laymen's terms, the line-items and corresponding amounts that were approved or denied in the Commission's order. However, this could prove challenging given the constrained timeline under which cases must be reviewed and Staff capacity constraints.

8. Are there administrative changes to the contested case process that could result in additional improvements such as shorter notice requirements or page limits? Other additions to the RCFR?

Staff Comment 8a: Not all rate cases are created equal when viewed through the lens of the entire process. Each and every rate case involves a full and complete audit by Staff, and review and analysis and recommendations by intervening parties. However, only a fraction of rate cases (37% since 2007) resulted in contested orders. Based on the data and discussion below, Staff believes that there could be merit to further investigation into administrative/process changes related to certain rate case filings. For purposes of this discussion, the term "DTECE4" is used to signify the rate case filing entities of DTE Electric, DTE Gas, Consumers Electric and Consumers Gas. The term "All Others" reflects all of the other electric, gas and steam utilities that file rate cases and are not included in the DTECE4.

There have been 86 rate cases that resulted in orders dating back to applications filed in or after 2007.[6] The data is split into distinct two time periods, 2017 and newer (the 10-month law) and then 2016-2007. The first takeaway from the data is that there is very little difference in the percentage of contested orders before and after the 2016 law that created the 10-month statutory deadline.

In total, 86 rate cases resulted in orders and only 32 of them (37%) resulted in contested orders. Said another way, the Commission has issued a contested order (deliberated) an average of 1.8 times per year since 2007 for rate cases – so just under twice per year on average.

However, when grouping the 86 rate cases into 2 utility groups (into DTECE4 and All Others) the results show meaningful differentiation. The DTECE4 had 43 rate cases with 27 of them (63%) resulting in contested orders. By comparison, All Others had 43 rate cases with only 5 of them (12%) resulting in contested orders.[7] Said another way, if the Commission had read the record for every single case for the All Others group dating back to 2007, the Commission would have deliberated just once every 3.5 to 4 years for those 43 cases.[8]

[6] Includes UMERC (U-21541) rate case settlement agreement awaiting Commission order.
[7] If you exclude I&M this becomes 8% (I&M had 2 contested orders out of 5 cases during this timeframe)
[8] If you exclude I&M this becomes once every 6 years.

Another noteworthy takeaway from the data shows that the electric cases within the DTECE4 rarely settle as 20 of 23 of them (87%) resulted in contested orders, while electric cases for All Others result in very few contested orders (5 of 28, or 18%). Similarly, the gas cases within All Others had zero contested orders (0 out of 12) dating back to 2007. These are meaningful differences between the two groups, further supporting that the All Others group could be handled differently from a bottleneck mitigation process standpoint.

Completed Cases w/ Application Dates in and after 2007 *							
DTECE4				All Others			
DTECE4 (Elec+Gas)	# Cases	Contested Orders	Cont-Order Percentage	All Others (Elec+Gas+Steam)	# Cases	Contested Orders	Cont-Order Percentage
2017-present	20	12	60%	2017-present	19	2	11%
2007-2016	23	15	65%	2007-2016	24	3	13%
Total of both periods	43	27	63%	Total of both periods	43	5	12%
				...excluding I&M	38	3	8%
DTECE4 Electric Only	# Cases	Contested Orders	Cont-Order Percentage	All Others Elec Only	# Cases	Contested Orders	Cont-Order Percentage
2017-present (Elec)	11	9	82%	2017-present (Elec)	13	2	15%
2007-2016 (Elec)	12	11	92%	2007-2016 (Elec)	15	3	20%
Total combined (Elec)	23	20	87%	Total combined (Elec)	28	5	18%
				...excluding I&M	23	3	13%
DTECE4 Gas Only	# Cases	Contested Orders	Cont-Order Percentage	All Others Gas Only	# Cases	Contested Orders	Cont-Order Percentage
2017-present (Gas)	9	3	33%	2017-present (Gas)	5	0	0%
2007-2016 (Gas)	11	4	36%	2007-2016 (Gas)	7	0	0%
Total combined (Gas)	20	7	35%	Total combined (Gas)	12	0	0%
All Utilities, 2007-now	86	32	37%	** Includes UMERC (U-21541) rate case settlement agreement awaiting Commission order*			
All Utilities, 2017-now	*39*	*14*	*36%*				
All Utilities, 2007-2016	*47*	*18*	*38%*				

Staff Comment 8b: Another distinction between the DTECE4 and All Others would be the size and complexity of the deliberation effort. The All Others group typically have a much smaller bucket of contested or contentious issues, thus making the deliberation effort much more manageable than compared to the DTECE4 which often have a wider variety and larger number of contested or contentious issue. Administrative changes to the manner in which the Commission reviews the group of All Others rate cases could help to mitigate the deliberation bottleneck discussed earlier, as well as the ongoing resource strain related to the number of (and workload for) the ALJs.

Staff Comment 8c: ALJ Strain/Relief: As the Commission order indicated, the PFDs issued in contested cases are enormous documents that have also expanded over time. It is truly amazing that a single ALJ can produce a full PFD in the timeframe allotted to them with the resources available to them. And as Staff understands it, there is a longstanding and continuing shortage of ALJs. The idea outlined below

would also help to mitigate the strain on ALJ resources by eliminating, shifting and/or repurposing some of the ALJ tasks.

Staff Comment 8d: Deliberation Window Expansion: If the Commission were to receive multiple rate case filings in a short timeframe, then the Commission may have a deliberation bottleneck concern as it discussed in the past. At that point, if the Commission determines that the bottleneck causes too many challenges under the current process, then the Commission could declare one or more of those cases to be read-the-record (RTR) cases. Strategically, declaring up front that the All Others (the non-DTE, non-CE) cases would be RTR cases would help to mitigate the deliberation bottleneck. For example, if three utilities were to file on March 1 (such as CE Elec, MGU and NSP Elec) then the Commission could have the CE Elec case follow the traditional approach while at the same time announce (up front at the time of filing) that the Commission will RTR for both of (or one of) the other 2 cases. In the slight chance that either of the two All Others cases (MGU, NSP Elec) require deliberation, this approach would create a meaningful expansion of the deliberation window which helps to mitigate the deliberation bottleneck.[9] By reading the record, the Commission removes the PFD, Exceptions and Replies from the process. At present, a typical rate case results in a 33-day deliberation and order preparation window, whereas a RTR case could increase that window to approximately 100 days by removing the PFD/Exceptions/Replies.[10] This expanded window would help to mitigate the deliberation bottleneck if and when utilities file in the same period. In the example above, if CE Elec, MGU and NSP-Elec were to file on the same day of March 1 then they would have almost identical deliberation windows under the current construct (deliberation window of approximately 33 days beginning approximately Nov 25). However, under this idea, in the 12% historical chance that MGU or NSP-Elec requires a contested order, the 100-day deliberation window would be open at approximately mid-September (well before late November) thus allowing the Commission to stagger its deliberation work well before the CE Electric deliberation window opens.[11] While the deliberation effort would be more work without a PFD, it seems reasonable to conclude that the Commission with its team of Commission advisors, Commission attorneys, and strategic operations staff (plus the technical staff that is no longer working within the case) would be able to deliberate and produce an order within 100 days given that the PFD is issued by an ALJ (who largely works solo or with very minimal assistance) in approximately 38-45 days. An example of the Commission reading the record efficiently and effectively in the past was demonstrated in Case No. U-16191, which was a Consumers Electric rate case. The Commission issued its order approximately 49 days after the Reply Briefs were filed (aka 49-day deliberation and order preparation window) which was approximately 79 days prior to the then 12-month statutory deadline.

A secondary consideration in this space would be that instead of removing the PFD completely, the Commission could have the ALJ prepare a summary-of-the-record document in lieu of a full PFD or in lieu of simply closing the record, but that would cut into the additional deliberation time. Across the

[9] Only 12% of orders for the All Others group were contested orders (5 out of 43) since 2007
[10] Some approved schedules in non-RTR rate cases have greater than 100 days from the reply brief to the statutory deadline; the current RTR schedule for Case No. U-21534 (the current DTE Elec Rate Case) includes 97 days from the filing of Reply Briefs on October 23, 2024 to the statutory deadline of approx. January 28, 2025.
[11] The Commission would need to weigh the benefit of the additional deliberation time against the lack of a PFD and additional resources required by Commission/staff to deliberate in a RTR situation. As mentioned elsewhere in this document, the number of contested issues and complexity of said issues in usually much smaller for the All Others group.

industry, the role of the ALJ has historically fit into one of three buckets of (a) administration of the hearing and creation of the record with no document produced, (b) same as 'a' but with a summary-of-the-record document, or (c) same as 'b' but with also including recommendations (this is Michigan).

Another secondary consideration would be to retain the full PFD as exists today but remove the Replies to Exceptions and/or the Exceptions to the PFD from the process. Removing the Replies to Exceptions stage from the process (while retaining the Exceptions to the PFD) would remove approximately 13 days from the standard schedule and create an additional 13 days in the deliberation window. This may very well be low hanging fruit that the Commission could take advantage of through any of the scheduling ideas discussed above, as Staff opines that the Replies to Exceptions may be less helpful than the Exceptions to the PFD with respect to the deliberation effort.[12] If the Commission were to consider removing both the Exceptions to the PFD and the Replies to Exceptions it would remove approximately 35 days from the standard schedule, thus creating an additional 35 days in the deliberation window. However, if a PFD is issued in a rate case then by statute there must be an opportunity for Exceptions to the PFD – which means that a change to effectuate removal of the Exceptions to the PFD stage would require further action/change.

Staff Comment 8e: **Would a mandated status or settlement conference with all parties and the administrative law judge benefit or assist the rate case process?** In most federal and state civil litigation, the process usually includes a status or settlement conference with the judge before the trial on the merits. In our process, would a required status or settlement conference shortly after the filing of reply briefs (and before the proposal for decision) benefit or assist the rate case process? For example, would a partial settlement be more likely, such that the disputed issues are reduced for the proposal for decision and the ultimate order in the matter? Would a full settlement be more likely if the parties were required to meet in a status or settlement conference? Or are parties mostly unwilling to stipulate or agree to any issue/fact in order to keep leverage in the case process? Could the utility be required to file a document after the conference listing all the uncontested issues and contested issues, which the other parties could supplement/contest?

Staff Comment 8f: **Would establishing a case schedule specifically for a contested settlement agreement (partial or full) improve the rate case process?** A contested settlement agreement has not been approved in a rate case. However, there have been contested settlements approved in integrated resource plans. Could a procedure be developed to give the objecting party or parties a reasonable opportunity to present evidence and argument while at the same time suspending the 10-month schedule for a short period? For example, if a contested settlement agreement is filed (which, of course, must include the utility), the schedule is suspended for 45-60 days; within 30 days, there must be a hearing, evidence, and argument presented, and the Commission would have 15-30 days to issue an order at a special commission meeting. It is unknown how the Commission would react to contested settlement agreements for rate cases.

[12] If the Commission removes the Replies to Exceptions from the standard rate case process then this would warrant an single, one time update to the Rate Case Filing Requirements to reflect that the stage has been removed.

9. What other improvements to the rate case process should be considered by the Commission or other entities?

Staff Comment 9a: Demand Response (DR)

In case No. U-18369, the Commission established the current three-phase approach to address DR issues. Under the three-phase approach, standalone DR reconciliation proceedings are conducted to reconcile actual utility spending on DR programs with the amounts approved in rate cases, as well as targets and costs included in approved integrated resource plans. This methodology was proposed and adopted during a time when DR was relatively new, and notable concerns were arising in rate cases regarding appropriate investment in DR programs.

After several years in practice, Staff has recognized multiple timing issues stemming from the segregated handling of DR across the three types of cases (IRPs, rate cases, and reconciliations). In addition to the potential for differing interpretations of audit periods, logistical difficulties arise because forward-looking rate cases and the DR reconciliation cases, which are by nature retrospective, frequently overlap. Such instances lead to historic spending on DR being carried forward for consideration in future rates prior to being subjected to prudency review in concurrent reconciliation cases. This is contrary to the intent of the three-phase approach.

Additionally, Staff believes the circumstances which initially led to the proposal of the three-phase approach either no longer exist (such as concerns about a deficiency of viable programs) or have not been sufficiently improved by it (such as concerns about appropriately incentivizing utilities to prioritize the cost-effectiveness of DR spending).

Experience navigating the three-phase approach, coupled with the growth and evolution of DR itself, has informed Staff's recommendation that a move away from the three-phase approach after the conclusion of the pending DR reconciliations would allow the Commission to better address these ongoing concerns. All DR information, including determinations about programs, historic spending, future investment, and considerations of DR incentives could be fully discussed within the context of the rate case, rather than split between rate cases and DR reconciliation cases, thus eliminating any further need for separate DR reconciliations. Since DR is considered a resource, higher level DR targets would still be discussed in the context of an integrated resource plan as they are today.

Final Comments

Once again, Staff notes that these Staff comments are responsive comments that can be primarily characterized as idea-based and/or solution-focused comments. Unless otherwise noted, Staff is not making any recommendations in these comments, and Staff is not advocating for any particular idea or outcome except where explicitly noted.

Staff believes that the current rate case construct can be characterized within the range of workable to reasonable. Staff also believes that the concept of "improvement" can result in a whack-a-mole situation – where the successful remedy of one problem has the potential to result in another problem popping up elsewhere. The rate case process from start to finish has many interested parties such as utilities, Staff, the AG, a multitude of other intervening parties, an ALJ, the Commission office (including Commissioners, Commission support staff, Commission legal team), etc. And the Staff has numerous sub-groups with varying stress points, bottlenecks, sensitivities, etc. While it may be possible to "improve" a certain facet of the rate case process, it is highly unlikely that each of the various interests within the rate case process would consider something an "improvement." Said another way, it is highly likely that an "improvement" in one facet, one stage, or for one group of people within the process would have an equal and opposite detrimental effect on a different facet, stage, or group within the process – and those interested parties or groups would consider such a change a regression not an improvement. In addition, the current construct and current process has the added certainty of having been tested over a number of years through the various cycles of administrative court, Commission orders, appeals, etc.

If anyone has questions regarding these comments, please feel free to contact Bill Stosik at 517-284-8252 or stosikb@michigan.gov

MPSC Case No.: U-21859
Requester: MNSC
Question No.: MNSC-DCC-3.1
Respondent: Shana Ramirez
Page: 1 of 3

QUESTION

Refer to the Rebuttal Testimony of Shana Ramirez, p. 31, lines 9-15:

a. Describe in detail what you mean by "implementation framework."
b. Describe in detail what you mean by "associated timelines."
c. Describe in detail what you mean by "operational implications."
d. Identify the source from whom you are seeking "further clarity" on the three factors just listed.
e. Explain what information and details you would need to have a "comprehensive understanding" of the three factors sufficient to "ensure informed decision-making and to avoid unintended impacts" regarding the proposed 60 percent renewable energy target.
f. Explain what process you propose or contemplate for implementing the proposed 60 percent renewable energy target for data center or new large load customers in light of the information on which you are seeking further clarity.
g. Explain in what way(s) the 60 percent renewable energy target is an "accelerated target."

OBJECTION OF COUNSEL:

DCC objects to each subpart of this request to the extent that it is overly broad and unduly burdensome. DCC further objects to subparts a through c of this request to the extent those subparts ask for definitions of terms that are commonly used and understood. Further objections to specific subparts are provided below.

Subject to and without waiving those objections, DCC responds as follows.

RESPONSE

a. For the purposes of my referenced testimony, the phrase "implementation framework" refers to the set of specific mechanisms, processes, rules, and other activities that would determine how the proposed 60 percent renewable energy target is applied to large-load customers, such as data centers.

b. For the purposes of my referenced testimony, the phrase "associated timelines" means the periods of time related to the mechanisms, processes, rules and other activities referenced in response to subpart a of this question.

c. For the purposes of my referenced testimony, the phrase "operational implications" means the implications of the proposed 60 percent renewable energy target on the operations of the utility and the customer.

MPSC Case No.: U-21859
Requester: MNSC
Question No.: MNSC-DCC-3.1
Respondent: Shana Ramirez
Page: 2 of 3

d. **OBJECTION OF COUNSEL**: DCC objects to this request to the extent it mischaracterizes the referenced testimony. Ms. Ramirez's referenced testimony does not state she is seeking further clarity. Subject to that objection, DCC responds as follows:

In my view, it would be prudent for the Commission and all relevant stakeholders to have more clarity on the three factors listed in subparts a-c of this request. While I expect that clarity may be provided in part by the parties proposing some variant of a 60 percent renewable energy target (MNSC, the Clean Energy Organizations (CEO) and the Attorney General), who would be in the best position to clarify the structure and details associated with their proposals, I would also expect further clarification from Consumers Energy Company, Michigan Public Service Commission Staff, and the Commission itself might be helpful or necessary to understand how the proposals can or should be implemented.

e. **OBJECTION OF COUNSEL:** DCC objects to this request on the grounds that it calls for speculation. DCC can offer certain information and details it would need to develop a comprehensive understanding, but the answers to these questions would likely trigger additional questions or otherwise preclude a comprehensive understanding. Subject to and without waiving this objection, DCC responds as follows:

See my rebuttal testimony at pages 25-34, and responses to subparts a through c of this request, for certain information and details that would be necessary to develop a comprehensive understanding.

From DCC's standpoint, in order to have a comprehensive understanding of the factors listed in this request, and of the 60 percent renewable energy targets proposed by MNSC and other parties more generally, DCC would need to know how Consumers Energy plans to meet the 60 percent renewable energy target specifically for data center customers, the resources Consumers Energy might use to meet such a target, if/how attributes from those resources would be assigned, how the costs of those resources might be allocated and recovered from customers, whether customers would have any ability to indicate preferences regarding the mix of resources used to meet the targets, whether customers would have any ability to contract directly for resources used to meet the targets, and whether or how the Company's plans would impact customers' energization timelines. Understanding these details is essential to evaluating whether the target is operationally feasible and consistent with data center customers' needs and objectives.

MPSC Case No.: U-21859
Requester: MNSC
Question No.: MNSC-DCC-3.1
Respondent: Shana Ramirez
Page: 3 of 3

f. See my rebuttal testimony at page 32. I recommend the Commission direct Consumers Energy to conduct further analysis and engage with stakeholders to evaluate the feasibility, implementation pathways, and timing of a 60 percent renewable energy target. This process should evaluate how different procurement options such as voluntary green pricing, on-site renewables, and long-term contracts could be used to meet the proposed target in a way that aligns with customer needs and objectives. This process should also evaluate potential cost impacts and administrative feasibility of such a target. I recommend the results of this process be reviewed by the Commission at a later date before any binding commitments are established. However, I am open to alternative structures for processes that would allow stakeholders to discuss and develop a proposed 60 percent renewable energy target.

g. It is my understanding, based on discussion with counsel and review of the testimony by intervenors in this proceeding, that Michigan law subjects Consumers Energy to a 60% renewable energy standard, which the Company must meet by 2035. It is my understanding that MNSC (and other parties) propose a 60% renewable energy target to be achieved (for a subset of customers) at an earlier date. The phrase “accelerated target” refers to the difference between 2035 and the earlier date.

EXHIBIT MEC-45

RESERVED

News Release

CMS Energy Announces Strong Second Quarter Results, Reaffirms 2025 Adjusted EPS Guidance

JACKSON, Mich., July 31, 2025 – CMS Energy announced today reported earnings per share of $0.66 for the second quarter of 2025, compared to $0.65 per share for 2024. The company's adjusted earnings per share for the second quarter were $0.71, compared to $0.66 per share for the same quarter in 2024. For the first six months of the year, the company reported $1.67 per share compared to $1.61 per share for the same timeframe in 2024. On an adjusted earnings per share basis year to date, the company reported $1.73 per share in 2025, compared to $1.63 per share in 2024, driven by constructive regulatory outcomes, cost-reduction initiatives and favorable weather.

CMS Energy reaffirmed its 2025 adjusted earnings guidance of $3.54 to $3.60 per share (*See below for important information about non-GAAP measures) and long-term adjusted EPS growth of 6 to 8 percent, with continued confidence toward the high end.

"Given the team's strong performance in the second quarter, we are on track to deliver on our earnings guidance and key operational objectives for the year, prioritizing investments in our electric and gas businesses to the benefit of our customers, investors and the communities we serve," said Garrick Rochow, President and CEO of CMS Energy and Consumers Energy. "I am also pleased to announce we have reached an agreement with a new data center, which is expected to add up to 1 gigawatt of load growth in our service territory, along with additional economic benefits for Michigan."

CMS Energy (NYSE: CMS) is a Michigan-based energy provider featuring Consumers Energy as its primary business. It also owns and operates independent power generation businesses.

# # #

CMS Energy will hold a webcast to discuss its 2025 second quarter results and provide a business and financial outlook on Thursday, July 31 at 9:30 a.m. (EDT). To participate in the webcast, go to CMS Energy's homepage (cmsenergy.com) and select "Events and Presentations."

Important information for investors about non-GAAP measures and other disclosures.

This news release contains non-Generally Accepted Accounting Principles (non-GAAP) measures, such as adjusted earnings. All references to net income refer to net income available to common stockholders and references to earnings per share are on a diluted basis. Adjustments could include items such as discontinued operations, asset sales, impairments, restructuring costs, business optimization initiative, major enterprise resource planning software implementations, changes in accounting principles, voluntary separation program, changes in federal and state tax policy, regulatory items from prior years, unrealized gains or losses from mark-to-market adjustments, recognized in net income related to NorthStar Clean Energy's interest expense, or other items. Management views adjusted earnings as a key measure of the company's present operating financial performance and uses adjusted earnings for external communications with analysts and investors. Internally, the company uses adjusted earnings to measure and assess performance. Because the company is not able to estimate the impact of specific line items, which have the potential to significantly impact, favorably or unfavorably, the company's reported earnings in future periods, the company is not providing reported earnings guidance nor is it providing a reconciliation for the comparable future period earnings. The company's adjusted earnings should be considered supplemental information to assist in understanding our business results, rather than as a substitute for the reported earnings.

This news release contains "forward-looking statements." The forward-looking statements are subject to risks and uncertainties that could cause CMS Energy's and Consumers Energy's results to differ materially. All forward-looking statements should be considered in the context of the risk and other factors detailed from time to time in CMS Energy's and Consumers Energy's Securities and Exchange Commission filings.

Investors and others should note that CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution.

Media Contacts: Katie Carey, 517/740-1739

Investment Analyst Contact: Travis Uphaus, 517/817-9241

CMS ENERGY CORPORATION
Consolidated Statements of Income
(Unaudited)

In Millions, Except Per Share Amounts

	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	Change	6/30/25	6/30/24	Change
Operating Revenue						
Electric utility	$ 1,359	$ 1,226	$ 133	$ 2,658	$ 2,358	$ 300
Gas utility	387	307	80	1,436	1,272	164
NorthStar Clean Energy	92	74	18	191	153	38
Total operating revenue	1,838	1,607	231	4,285	3,783	502
Operating Expenses						
Fuel for electric generation	134	114	20	351	270	81
Purchased and interchange power	439	349	90	819	663	156
Purchased power – related parties	30	16	14	48	34	14
Cost of gas sold	124	66	58	507	417	90
Maintenance and other operating expenses	397	404	(7)	802	806	(4)
Depreciation and amortization	288	273	15	676	641	35
General taxes	109	102	7	271	257	14
Total operating expenses	1,521	1,324	197	3,474	3,088	386
Operating Income (Loss)						
Electric utility	263	244	19	465	405	60
Gas utility	65	43	22	376	294	82
NorthStar Clean Energy	(8)	(1)	(7)	(25)	2	(27)
Other	(3)	(3)	-	(5)	(6)	1
Total operating income	317	283	34	811	695	116
Other Income (Expense)						
Nonoperating retirement benefits, net	47	41	6	89	85	4
Other income	95	77	18	109	121	(12)
Other expense	(5)	(5)	-	(11)	(7)	(4)
Total other income	137	113	24	187	199	(12)
Earnings Before Interest, Taxes, and Other Charges	454	396	58	998	894	104
Interest on long-term debt	199	171	28	386	343	43
Interest expense - related parties	3	3	-	6	6	-
Other interest expense	-	5	(5)	(1)	7	(8)
Allowance for borrowed funds used during construction	(3)	(6)	3	(6)	(6)	-
Income tax expense	62	41	21	125	99	26
Net Income	193	182	11	488	445	43
Loss attributable to noncontrolling interests	(8)	(16)	8	(17)	(40)	23
Net Income Attributable to CMS Energy	201	198	3	505	485	20
Preferred stock dividends	3	3	-	5	5	-
Net Income Available to Common Stockholders	$ 198	$ 195	$ 3	$ 500	$ 480	$ 20
Reconciling items:						
Other exclusions from adjusted earnings	5	2	3	8	6	2
Tax impact	(1)	(*)	(1)	(2)	(1)	(1)
State tax policy change	12	-	12	12	-	12
Voluntary separation program	-	-	-	-	*	(*)
Tax impact	-	-	-	-	(*)	*
Adjusted Net Income – Non-GAAP	$ 214	$ 197	$ 17	$ 518	$ 485	$ 33
Average Common Shares Outstanding - Diluted	299.1	298.5	0.6	299.0	297.9	1.1
Diluted Earnings Per Average Common Share	$ 0.66	$ 0.65	$ 0.01	$ 1.67	$ 1.61	$ 0.06
Reconciling items:						
Other exclusions from adjusted earnings	0.01	0.01	-	0.02	0.02	-
Tax impact	(*)	(*)	(*)	(*)	(*)	(*)
State tax policy change	0.04	-	0.04	0.04	-	0.04
Voluntary separation program	-	-	-	-	*	(*)
Tax impact	-	-	-	-	(*)	*
Adjusted Diluted Earnings Per Average Common Share – Non-GAAP	$ 0.71	$ 0.66	$ 0.05	$ 1.73	$ 1.63	$ 0.10

* Less than $0.5 million or $0.01 per share.

CMS ENERGY CORPORATION
Summarized Consolidated Balance Sheets
(Unaudited)

In Millions

	As of	
	6/30/25	12/31/24
Assets		
Current assets		
Cash and cash equivalents	$ 844	$ 103
Restricted cash and cash equivalents	81	75
Other current assets	2,268	2,612
Total current assets	3,193	2,790
Non-current assets		
Plant, property, and equipment	28,847	27,461
Other non-current assets	5,659	5,669
Total Assets	$ 37,699	$ 35,920
Liabilities and Equity		
Current liabilities [1]	$ 2,071	$ 2,261
Non-current liabilities [1]	8,612	8,345
Capitalization		
Debt and finance leases (excluding securitization debt) [2]	17,402	15,866
Preferred stock and securities	224	224
Noncontrolling interests	577	518
Common stockholders' equity	8,170	8,006
Total capitalization (excluding securitization debt)	26,373	24,614
Securitization debt [2]	643	700
Total Liabilities and Equity	$ 37,699	$ 35,920

[1] Excludes debt and finance leases.

[2] Includes current and non-current portions.

CMS ENERGY CORPORATION
Summarized Consolidated Statements of Cash Flows
(Unaudited)

In Millions

	Six Months Ended	
	6/30/25	6/30/24
Beginning of Period Cash and Cash Equivalents, Including Restricted Amounts	$ 178	$ 248
Net cash provided by operating activities	1,414	1,663
Net cash used in investing activities	(1,880)	(1,246)
Cash flows from operating and investing activities	(466)	417
Net cash provided by financing activities	1,213	124
Total Cash Flows	$ 747	$ 541
End of Period Cash and Cash Equivalents, Including Restricted Amounts	$ 925	$ 789

CMS ENERGY CORPORATION
Selected Financial Data
(Unaudited)

In Millions

	Twelve Months Ended		
	6/30/25	12/31/24	6/30/24
EBIT – Non-GAAP [1]			
Consolidated	$ 1,943	$ 1,837	$ 1,746
Consumers Energy	1,865	1,733	1,621
Depreciation and Amortization			
Consolidated	$ 1,275	$ 1,240	$ 1,213
Consumers Energy	1,225	1,191	1,165
EBITDA – Non-GAAP [1]			
Consolidated	$ 3,218	$ 3,077	$ 2,959
Consumers Energy	3,090	2,924	2,786
Dividends and Other Distributions From Subsidiaries	$ 852	$ 900	$ 904
Interest Expense, Net			
Consolidated	$ 743	$ 708	$ 686
Energy parent	233	205	206
Consumers Energy	508	499	477

In Millions

	As of		
	6/30/25	12/31/24	6/30/24
Book Value Per Share	$ 27.29	$ 26.79	$ 26.04
Common Shares Outstanding – End of Period	299.3	298.8	298.7
Average Common Shares Outstanding			
Basic	298.4	297.6	297.2
Diluted	299.0	298.3	297.9
Debt [2]			
Energy parent	$ 4,461	$ 4,143	$ 4,473
NorthStar Clean Energy	337	192	147
Consumers Energy (excluding securitization bonds)	12,604	11,531	10,376
Consolidated (excluding securitization bonds)	17,402	15,866	14,996
Securitization bonds	643	700	772
Consolidated	$ 18,045	$ 16,566	$ 15,768
Unrestricted Cash and Cash Equivalents			
Energy parent	$ 166	$ 4	$ 53
Consumers Energy	599	44	607
CMS Treasury Services	49	31	15
Other	30	24	24
Consolidated	$ 844	$ 103	$ 699
Consumers Energy			
Regulated Common Equity Ratio (13-Month Average)			
Electric	41.2%	41.2%	41.6%
Gas	41.2%	41.2%	41.6%
Regulated Rate Base (13-Month Average, in Millions)			
Electric [3]	$ 16,610	$ 15,878	$ 15,620
Gas	10,346	9,987	9,684
Regulated Return on Average Common Equity (12-Month Ended)			
Electric [3]	10.2%	10.1%	9.1%
Gas	9.4%	7.8%	8.1%

[1] EBIT (non-GAAP) equals net income available to common stockholders + income taxes + interest charges + noncontrolling interests + discontinued operations + writedowns + impairments + losses (gains) on asset sales + accounting changes. EBITDA (non-GAAP) equals EBIT + depreciation and amortization.

[2] Includes current maturities, leases and notes payable.

[3] Includes Renewable Portfolio Standard (RPS) renewables rate base of ~$1.9 billion in total.

CMS ENERGY CORPORATION
Reconciliations of GAAP Net Income to Non-GAAP EBIT and EBITDA
(Unaudited)

In Millions

	Twelve Months Ended		
	6/30/25	12/31/24	6/30/24
Net Income Available to Common Stockholders	$ 1,013	$ 993	$ 960
Reconciling items:			
Income tax expense	190	176	176
Interest on long-term debt	743	700	663
Interest expense - related parties	12	12	12
Other interest expense	6	14	19
Allowance for borrowed funds used during construction	(18)	(18)	(8)
Loss attributable to noncontrolling interests	(33)	(56)	(101)
Preferred stock dividends	10	10	10
Other exclusions from adjusted earnings	8	6	10
State tax policy change	12	-	-
Voluntary separation program	-	-	5
EBIT – Non-GAAP	1,943	1,837	1,746
Additional reconciling items:			
Depreciation and amortization	1,275	1,240	1,213
EBITDA – Non-GAAP	$ 3,218	$ 3,077	$ 2,959

CONSUMERS ENERGY COMPANY
Reconciliations of GAAP Net Income to Non-GAAP EBIT and EBITDA
(Unaudited)

In Millions

	Twelve Months Ended		
	6/30/25	12/31/24	6/30/24
Net Income Available to Common Stockholder	$ 1,088	$ 1,007	$ 919
Reconciling items:			
Income tax expense	225	200	194
Interest on long-term debt	500	488	456
Interest expense - related parties	38	31	26
Other interest expense	10	12	15
Allowance for borrowed funds used during construction	(14)	(13)	(6)
Preferred stock dividends	2	2	2
Other exclusions from adjusted earnings	4	6	10
State tax policy change	12	-	-
Voluntary separation program	-	-	5
EBIT – Non-GAAP	1,865	1,733	1,621
Additional reconciling items:			
Depreciation and amortization	1,225	1,191	1,165
EBITDA – Non-GAAP	$ 3,090	$ 2,924	$ 2,786

CMS ENERGY CORPORATION
Non-GAAP Adjusted Earnings Per Share Variance Analysis
(Unaudited)

Three Months Ended June 30

	6/30/25	6/30/24	Variance
Adjusted EPS – Non-GAAP			
Electric utility	$ 0.59	$ 0.57	$ 0.02
Gas utility	0.10	0.06	0.04
NorthStar Clean Energy	0.07	0.05	0.02
Energy parent	(0.05)	(0.02)	(0.03)
Consolidated	$ 0.71	$ 0.66	$ 0.05

Variance Explanations:

ELECTRIC UTILITY

- Deliveries of 8,948 GWh, up 11 GWh (weather-driven impact, down 21 GWh)	$ (0.03)
- Electric rate relief and renewables	0.09
- Lower operating & maintenance expenses, including service restoration, net of storm expense deferral impacts	0.03
- Higher investment costs (depreciation, property taxes & fixed costs)	(0.07)
- Change in shares outstanding	*
	$ 0.02

GAS UTILITY

- Deliveries, including transportation to end-use customers, of 49.1 bcf, up 8.1 bcf (weather-driven impact, up 4.5 bcf)	$ 0.06
- Gas rate relief	0.03
- Higher operating & maintenance expenses	(0.02)
- Higher investment costs (depreciation, property taxes & fixed costs)	(0.03)
- Change in shares outstanding	*
	$ 0.04

NORTHSTAR CLEAN ENERGY AND ENERGY PARENT

- NorthStar Clean Energy	$ 0.02
- Energy parent, including corporate financing activities	(0.03)
- Change in shares outstanding	*
	$ (0.01)

WEATHER IMPACTS

	6/30/25	6/30/24
Weather		
- Warmer (colder) than normal using 15-year average temperatures	- %	5.4 %
Electric Utility		
- Increase (decrease) from normal in:		
Electric sales (GWh)	147	168
EPS	$ 0.05	$ 0.05
Gas Utility		
- Increase (decrease) from normal in:		
Gas sales (bcf)	-	(4.5)
EPS	$ -	$ (0.06)
Total EPS Weather Impacts	$ 0.05	$ (0.01)

* Less than $0.01 per share.

CMS ENERGY CORPORATION
Non-GAAP Adjusted Earnings Per Share Variance Analysis
(Unaudited)

Six Months Ended June 30

	6/30/25	6/30/24	Variance
Adjusted EPS – Non-GAAP			
Electric utility	$ 1.01	$ 0.91	$ 0.10
Gas utility	0.81	0.62	0.19
NorthStar Clean Energy	0.02	0.16	(0.14)
Energy parent	(0.11)	(0.06)	(0.05)
Consolidated	$ 1.73	$ 1.63	$ 0.10

Variance Explanations:

ELECTRIC UTILITY

- Deliveries of 17,975 GWh, up 81 GWh (weather-driven impact, up 223 GWh)	$ 0.03
- Electric rate relief and renewables	0.20
- Higher operating & maintenance expenses	(0.02)
- Higher investment costs (depreciation, property taxes & fixed costs)	(0.11)
- Change in shares outstanding	*
	$ 0.10

GAS UTILITY

- Deliveries, including transportation to end-use customers, of 183.7 bcf, up 25.8 bcf (weather-driven impact, up 21.5 bcf)	$ 0.21
- Gas rate relief	0.08
- Higher operating & maintenance expenses	(0.02)
- Higher investment costs (depreciation, property taxes & fixed costs)	(0.08)
- Change in shares outstanding	*
	$ 0.19

NORTHSTAR CLEAN ENERGY AND ENERGY PARENT

- NorthStar Clean Energy	$ (0.14)
- Energy parent, including corporate financing activities	(0.05)
- Change in shares outstanding	*
	$ (0.19)

WEATHER IMPACTS

	6/30/25	6/30/24
Weather		
- Warmer (colder) than normal using 15-year average temperatures	0.5 %	10.3 %
Electric Utility		
- Increase (decrease) from normal in:		
Electric sales (GWh)	138	(85)
EPS	$ 0.05	$ (0.02)
Gas Utility		
- Increase (decrease) from normal in:		
Gas sales (bcf)	(0.9)	(22.4)
EPS	$ (0.01)	$ (0.26)
Total EPS Weather Impacts	$ 0.04	$ (0.28)

* Less than $0.01 per share.

CMS ENERGY CORPORATION
Reconciliation of GAAP EPS to Non-GAAP Adjusted EPS by Segment
(Unaudited)

In Millions, Except Per Share Amounts

	Three Months Ended		Six Months Ended	
	6/30/25	6/30/24	6/30/25	6/30/24
Electric Utility				
Reported net income per share	$ 0.55	$ 0.57	$ 0.97	$ 0.90
Reconciling items:				
Other exclusions from adjusted earnings	0.01	*	0.01	0.01
Tax impact	(*)	(*)	(*)	(*)
State tax policy change	0.03	-	0.03	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income per share – non-GAAP	$ 0.59	$ 0.57	$ 1.01	$ 0.91
Gas Utility				
Reported net income per share	$ 0.09	$ 0.05	$ 0.80	$ 0.61
Reconciling items:				
Other exclusions from adjusted earnings	*	0.01	*	0.01
Tax impact	(*)	(*)	(*)	(*)
State tax policy change	0.01	-	0.01	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income per share – non-GAAP	$ 0.10	$ 0.06	$ 0.81	$ 0.62
NorthStar Clean Energy				
Reported net income per share	$ 0.07	$ 0.05	$ 0.01	$ 0.16
Reconciling items:				
Other exclusions from adjusted earnings	*	-	0.01	-
Tax impact	(*)	-	(*)	-
Adjusted net income per share – non-GAAP	$ 0.07	$ 0.05	$ 0.02	$ 0.16
Corporate Interest and Other				
Reported net income (loss) per share	$ (0.05)	$ (0.02)	$ (0.11)	$ (0.06)
Reconciling items:				
State tax policy change	(*)	-	(*)	-
Adjusted net income (loss) per share – non-GAAP	$ (0.05)	$ (0.02)	$ (0.11)	$ (0.06)
Consolidated				
Reported net income per share	$ 0.66	$ 0.65	$ 1.67	$ 1.61
Reconciling items:				
Other exclusions from adjusted earnings	0.01	0.01	0.02	0.02
Tax impact	(*)	(*)	(*)	(*)
State tax policy change	0.04	-	0.04	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income per share – non-GAAP	$ 0.71	$ 0.66	$ 1.73	$ 1.63
Average Common Shares Outstanding – Diluted	299.1	298.5	299.0	297.9

* Less than $0.01 per share.

CMS ENERGY CORPORATION
Reconciliation of GAAP Net Income to Non-GAAP Adjusted Net Income
(Unaudited)

In Millions, Except Per Share Amounts

	Three Months Ended		Six Months Ended	
	6/30/25	6/30/24	6/30/25	6/30/24
Net Income Available to Common Stockholders	$ 198	$ 195	$ 500	$ 480
Reconciling items:				
Other exclusions from adjusted earnings**	5	2	8	6
Tax impact	(1)	(*)	(2)	(1)
State tax policy change	12	-	12	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income – non-GAAP	$ 214	$ 197	$ 518	$ 485
Average Common Shares Outstanding - Diluted	299.1	298.5	299.0	297.9
Diluted Earnings Per Average Common Share				
Reported net income per share	$ 0.66	$ 0.65	$ 1.67	$ 1.61
Reconciling items:				
Other exclusions from adjusted earnings**	0.01	0.01	0.02	0.02
Tax impact	(*)	(*)	(*)	(*)
State tax policy change	0.04	-	0.04	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income per share – non-GAAP	$ 0.71	$ 0.66	$ 1.73	$ 1.63

* Less than $0.5 million or $0.01 per share.

** Includes restructuring costs and business optimization initiative.

Management views adjusted (non-Generally Accepted Accounting Principles) earnings as a key measure of the Company's present operating financial performance and uses adjusted earnings for external communications with analysts and investors. Internally, the Company uses adjusted earnings to measure and assess performance. Adjustments could include items such as discontinued operations, asset sales, impairments, restructuring costs, business optimization initiative, major enterprise resource planning software implementations, changes in accounting principles, voluntary separation program, changes in federal and state tax policy, regulatory items from prior years, unrealized gains or losses from mark-to-market adjustments, recognized in net income related to NorthStar Clean Energy's interest expense, or other items. The adjusted earnings should be considered supplemental information to assist in understanding our business results, rather than as a substitute for reported earnings.

CMS ENERGY CORPORATION
Reconciliation of GAAP Net Income to Non-GAAP Adjusted Net Income by Quarter
(Unaudited)

In Millions, Except Per Share Amounts

	2025	
	1Q	2Q
Net Income Available to Common Stockholders	$ 302	$ 198
Reconciling items:		
Electric utility and gas utility	*	4
Tax impact	(*)	11
NorthStar Clean Energy	3	1
Tax impact	(1)	(*)
Corporate interest and other	-	-
Tax impact	-	(*)
Adjusted Net Income – Non-GAAP	$ 304	$ 214
Average Common Shares Outstanding – Diluted	299.1	299.1
Diluted Earnings Per Average Common Share	$ 1.01	$ 0.66
Reconciling items:		
Electric utility and gas utility	*	0.01
Tax impact	(*)	0.04
NorthStar Clean Energy	0.01	*
Tax impact	(*)	(*)
Corporate interest and other	-	-
Tax impact	-	(*)
Adjusted Diluted Earnings Per Average Common Share – Non-GAAP	$ 1.02	$ 0.71

In Millions, Except Per Share Amounts

	2024			
	1Q	2Q	3Q	4Q
Net Income Available to Common Stockholders	$ 285	$ 195	$ 251	$ 262
Reconciling items:				
Electric utility and gas utility	4	2	*	*
Tax impact	(1)	(*)	(*)	(*)
NorthStar Clean Energy	-	-	-	-
Tax impact	-	-	-	-
Corporate interest and other	-	-	-	-
Tax impact	-	-	-	-
Disposal of discontinued operations (gain) loss	-	-	-	(*)
Tax impact	-	-	-	*
Adjusted Net Income – Non-GAAP	$ 288	$ 197	$ 251	$ 262
Average Common Shares Outstanding – Diluted	297.2	298.5	298.8	298.7
Diluted Earnings Per Average Common Share	$ 0.96	$ 0.65	$ 0.84	$ 0.87
Reconciling items:				
Electric utility and gas utility	0.01	0.01	*	*
Tax impact	(*)	(*)	(*)	(*)
NorthStar Clean Energy	-	-	-	-
Tax impact	-	-	-	-
Corporate interest and other	-	-	-	-
Tax impact	-	-	-	-
Disposal of discontinued operations (gain) loss	-	-	-	(*)
Tax impact	-	-	-	*
Adjusted Diluted Earnings Per Average Common Share – Non-GAAP	$ 0.97	$ 0.66	$ 0.84	$ 0.87

* Less than $0.5 million or $0.01 per share.

CONSUMERS ENERGY COMPANY
Consolidated Statements of Income
(Unaudited)

In Millions

	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	Change	6/30/25	6/30/24	Change
Operating Revenue						
Electric utility	$ 1,359	$ 1,226	$ 133	$ 2,658	$ 2,358	$ 300
Gas utility	387	307	80	1,436	1,272	164
Total operating revenue	1,746	1,533	213	4,094	3,630	464
Operating Expenses						
Fuel for electric generation	113	91	22	306	216	90
Purchased and interchange power	394	337	57	729	643	86
Purchased power – related parties	30	16	14	48	34	14
Cost of gas sold	123	66	57	505	416	89
Maintenance and other operating expenses	376	377	(1)	749	755	(6)
Depreciation and amortization	276	261	15	651	617	34
General taxes	106	99	7	265	251	14
Total operating expenses	1,418	1,247	171	3,253	2,932	321
Operating Income (Loss)						
Electric utility	263	244	19	465	405	60
Gas utility	65	43	22	376	294	82
Other	-	(1)	1	-	(1)	1
Total operating income	328	286	42	841	698	143
Other Income (Expense)						
Nonoperating retirement benefits, net	45	38	7	84	79	5
Other income	19	26	(7)	29	43	(14)
Other expense	(4)	(5)	1	(7)	(7)	-
Total other income	60	59	1	106	115	(9)
Interest Charges						
Interest on long-term debt	131	120	11	253	241	12
Interest expense - related parties	10	7	3	20	13	7
Other interest expense	3	3	-	3	5	(2)
Allowance for borrowed funds used during construction	(3)	(4)	1	(5)	(4)	(1)
Total interest charges	141	126	15	271	255	16
Income Before Income Taxes	247	219	28	676	558	118
Income Tax Expense	59	41	18	142	105	37
Net Income	188	178	10	534	453	81
Preferred Stock Dividends	1	1	-	1	1	-
Net Income (Loss) Available to Common Stockholder						
Electric utility	167	170	(3)	291	267	24
Gas utility	25	15	10	238	184	54
Other	(5)	(8)	3	4	1	3
Total net income available to common stockholder	$ 187	$ 177	$ 10	$ 533	$ 452	$ 81

CONSUMERS ENERGY COMPANY
Electric Utility Statistics
(Unaudited)

In Millions of kWh, Except as Noted

	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	% Change	6/30/25	6/30/24	% Change
Electric Deliveries						
Residential	2,963	2,933	1.0	6,168	5,979	3.2
Commercial	2,817	2,920	(3.5)	5,728	5,752	(0.4)
Industrial	2,237	2,096	6.7	4,278	4,252	0.6
Other	25	27	(7.4)	60	66	(9.1)
Wholesale	-	59	(100.0)	1	124	(99.2)
Retail open access	906	902	0.4	1,740	1,721	1.1
Total customer deliveries	8,948	8,937	0.1	17,975	17,894	0.5
Intersystem	1,381	1,463	(5.6)	3,321	3,200	3.8
Total electric deliveries	10,329	10,400	(0.7)	21,296	21,094	1.0
Weather-Normalized Electric Deliveries [1]						
Residential	2,817	2,834	(0.6)	6,032	6,074	(0.7)
Commercial	2,815	2,861	(1.6)	5,726	5,752	(0.5)
Industrial	2,239	2,088	7.2	4,279	4,244	0.8
Other	25	27	(7.4)	60	66	(9.1)
Wholesale	-	59	(100.0)	1	124	(99.2)
Retail open access	905	900	0.6	1,739	1,719	1.2
Total weather-normalized electric deliveries	8,801	8,769	0.4	17,837	17,979	(0.8)
Weather-Normalized Electric Deliveries [1] **(By Class, Including Retail Open Access)**						
Residential	2,817	2,834	(0.6)	6,032	6,074	(0.7)
Commercial	3,050	3,092	(1.4)	6,191	6,195	(0.1)
Industrial	2,909	2,757	5.5	5,553	5,520	0.6
Other	25	27	(7.4)	60	66	(9.1)
Wholesale	-	59	(100.0)	1	124	(99.2)
Total weather-normalized electric deliveries	8,801	8,769	0.4	17,837	17,979	(0.8)

[1] Excludes intersystem deliveries.

In Millions, Except as Noted

	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	% Change	6/30/25	6/30/24	% Change
Electric Utility Revenue						
Residential	$ 619	$ 547	13.2	$ 1,213	$ 1,072	13.2
Commercial	473	433	9.2	891	793	12.4
Industrial	199	174	14.4	372	330	12.7
Other	11	10	10.0	21	18	16.7
Total sales revenue	1,302	1,164	11.9	2,497	2,213	12.8
Wholesale	-	5	(100.0)	-	10	(100.0)
Retail open access	12	11	9.1	24	20	20.0
Intersystem	33	32	3.1	110	88	25.0
Miscellaneous	12	14	(14.3)	27	27	-
Total electric utility revenue	$ 1,359	$ 1,226	10.8	$ 2,658	$ 2,358	12.7

CONSUMERS ENERGY COMPANY
Gas Utility Statistics
(Unaudited)

In Thousands of mcf, Except as Noted

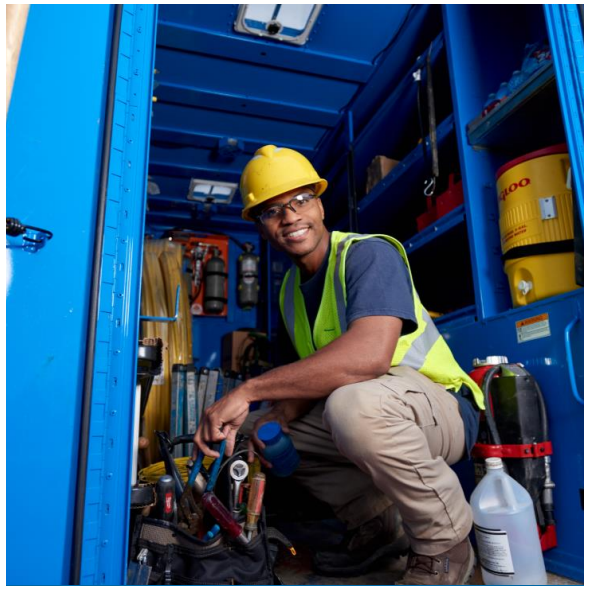
	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	% Change	6/30/25	6/30/24	% Change
Gas Deliveries						
Residential	22,022	17,418	26.4	94,619	81,548	16.0
Commercial	8,554	7,442	14.9	36,704	31,354	17.1
Industrial	970	1,023	(5.2)	4,964	4,125	20.3
Other	12	10	20.0	60	52	15.4
Transportation	17,523	15,092	16.1	47,295	40,790	15.9
Total customer deliveries	49,081	40,985	19.8	183,642	157,869	16.3
Off-system transportation						
MCV	15,974	18,897	(15.5)	31,822	37,806	(15.8)
Other	4,570	4,734	(3.5)	7,874	7,518	4.7
Total gas deliveries	69,625	64,616	7.8	223,338	203,193	9.9
Weather-Normalized Gas Deliveries [1]						
Residential	21,744	20,933	3.9	95,093	97,120	(2.1)
Commercial	8,480	7,913	7.2	36,404	35,902	1.4
Industrial	966	1,114	(13.3)	4,994	4,390	13.8
Other	12	17	(29.4)	61	66	(7.6)
Transportation	17,892	15,524	15.3	48,040	42,808	12.2
Total weather-normalized gas deliveries	49,094	45,501	7.9	184,592	180,286	2.4
Weather-Normalized Gas Deliveries [1] **(By Class, Including Transportation)**						
Residential	21,900	21,096	3.8	95,823	97,803	(2.0)
Commercial	13,524	13,231	2.2	52,351	51,774	1.1
Industrial	13,653	11,157	22.4	36,352	30,638	18.7
Other	17	17	-	66	71	(7.0)
Total weather-normalized gas deliveries	49,094	45,501	7.9	184,592	180,286	2.4

[1] Excludes off-system transportation deliveries.

In Millions, Except as Noted

	Three Months Ended			Six Months Ended		
	6/30/25	6/30/24	% Change	6/30/25	6/30/24	% Change
Gas Utility Revenue						
Residential	$ 276	$ 206	34.0	$ 1,007	$ 871	15.6
Commercial	90	64	40.6	329	271	21.4
Industrial	10	8	25.0	40	32	25.0
Other	-	1	-	-	1	(100.0)
Total sales revenue	376	279	34.8	1,376	1,175	17.1
Transportation	26	26	-	67	69	(2.9)
Miscellaneous	(15)	2	(850.0)	(7)	28	(125.0)
Total gas utility revenue	$ 387	$ 307	26.1	$ 1,436	$ 1,272	12.9

LEADING THE CLEAN ENERGY TRANSFORMATION



2025 Second Quarter Results & Outlook

July 31, 2025

CMS ENERGY

This presentation is made as of the date hereof and contains "forward-looking statements" as defined in Rule 3b-6 of the Securities Exchange Act of 1934, Rule 175 of the Securities Act of 1933, and relevant legal decisions. The forward-looking statements are subject to risks and uncertainties. All forward-looking statements should be considered in the context of the risk and other factors detailed from time to time in CMS Energy's and Consumers Energy's Securities and Exchange Commission filings. Forward-looking statements should be read in conjunction with "FORWARD-LOOKING STATEMENTS AND INFORMATION" and "RISK FACTORS" sections of CMS Energy's and Consumers Energy's most recent Form 10-K and as updated in reports CMS Energy and Consumers Energy file with the Securities and Exchange Commission. CMS Energy's and Consumers Energy's "FORWARD-LOOKING STATEMENTS AND INFORMATION" and "RISK FACTORS" sections are incorporated herein by reference and discuss important factors that could cause CMS Energy's and Consumers Energy's results to differ materially from those anticipated in such statements. CMS Energy and Consumers Energy undertake no obligation to update any of the information presented herein to reflect facts, events or circumstances after the date hereof.

The presentation also includes non-GAAP measures when describing CMS Energy's results of operations and financial performance. A reconciliation of each of these measures to the most directly comparable GAAP measure is included in the appendix and posted on our website at www.cmsenergy.com.

Investors and others should note that CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution.

Presentation endnotes are included after the appendix.

Investment Thesis . . .

Over two decades of industry-leading financial performance

Industry-leading clean energy commitments

Excellence through the CE WAY

Top-tier regulatory jurisdiction[a] with attractive growth

Premium total shareholder return
6% to 8% adjusted EPS growth + ~3% dividend yield

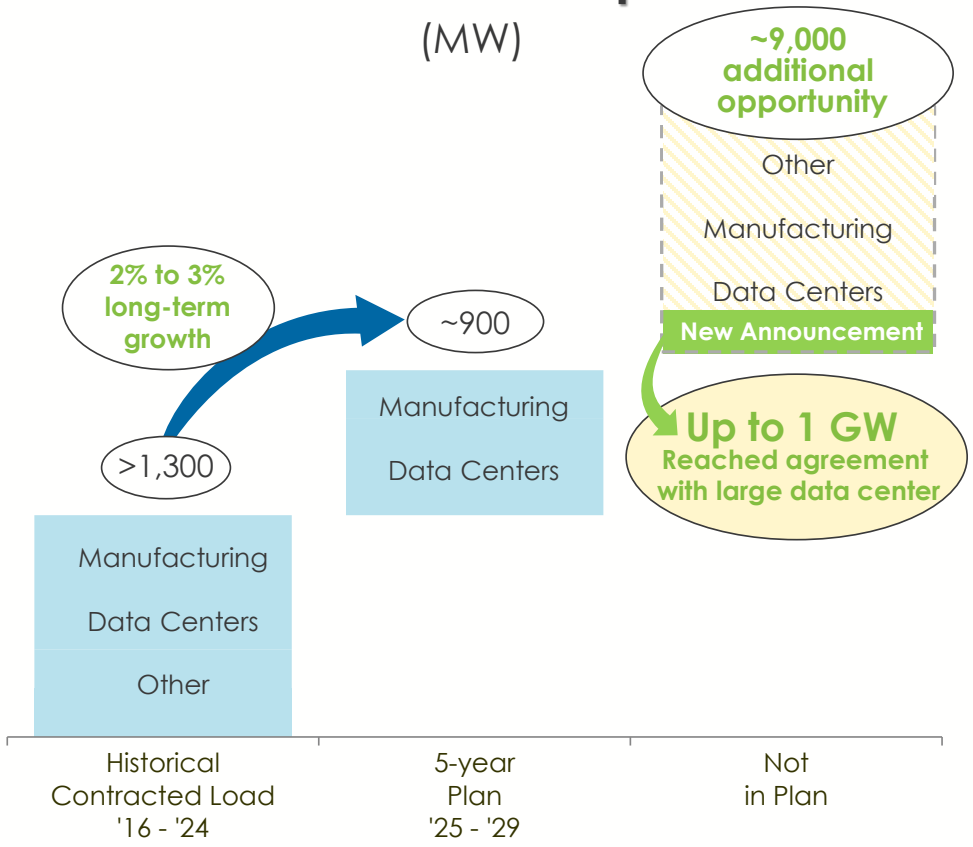
Presentation endnotes are included after the appendix.

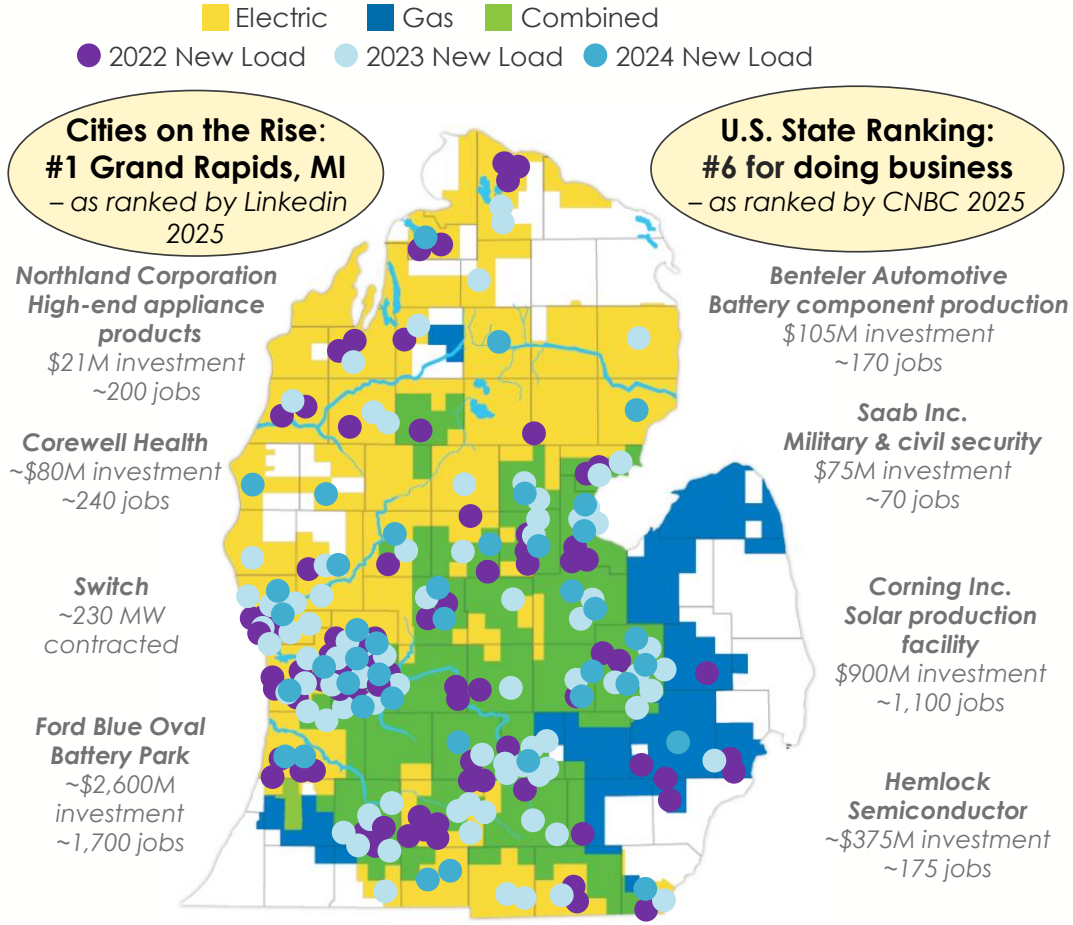
. . . is simple, clean and lean.

Expansive Economic Development Efforts . . .

Economic Development

(MW)

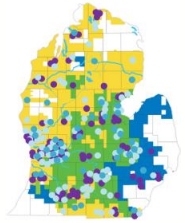




. . . drive diversified growth, including data centers, across Michigan and reduce customer rates.

Key Affordability Drivers. . .

Key Affordability Drivers



✓ **Economic development**

- 2% to 3% long-term annual sales growth with upward pressure from growing demand
- ~9 GW pipeline opportunity, including data centers

✓ **CE WAY and episodic cost savings**

- ~$70M savings per year
- Lower operating and PPA costs

✓ **Energy Waste Reduction programs**

- >2% reduction in customer usage per year; ~$7.3B in customer savings since 2009

Presentation endnotes are included after the appendix.

Long-Term Customer Investment

Not in Plan

- **Electric Reliability Roadmap** — **$10B**
  - Up to 400 miles/yr undergrounding
  - 20K/yr poles replaced
- **Renewable Energy Plan** — **$10B**
  - +8 GW solar, +2.8 GW wind
  - Supports MI's renewable mandates
- **Integrated Resource Plan (2026)** — **$5B+[a]**
  - Additional storage
  - New gas capacity

Total Capex Opportunity **$25B+[a]**

. . . support long-term and growing customer investment backlog.

CMS Energy is Well-Positioned . . .

Federal Actions	Considerations	CMS Energy Response
One Big Beautiful Bill Act		
Utility	• Safe harbor pipeline	✓ Expect safe harbor[a] through 2029 ✓ Utility PPAs with FCM adder – and continued interest from developers to pull projects forward for potential BTA
	• Affordability	✓ CE Way/episodic savings
	• Transferability	✓ Transferability[a] in Plan at Utility derisked
	• Capex opportunities	✓ MI Energy Law (100% clean energy by 2040)
NorthStar	• Safe harbor pipeline • Commercial renewables • Earnings contribution	✓ Expect safe harbor[a] through 2028 ✓ DIG re-contracting ✓ Capital allocation flexibility
Campbell (DOE Order)	• Cost recovery • Compliance • Additional capacity	✓ Filed w/FERC (June 6th) for cost recovery from North and Central MISO customers ✓ Dispatching as baseload
Tariff Impacts	• Cost containment	✓ Manageable inflationary impacts skewed toward capital ($240K exposure to date)
	• Material availability	✓ ~90% of supply chain domestically sourced with broad vendor redundancy

Presentation endnotes are included after the appendix.

. . . to continue to drive 6% to 8% long-term growth.

Michigan's Strong Regulatory Environment . . .

Supportive Energy Policy

- **Timely recovery of investments**
  - ✓ Forward-looking test years/earn authorized ROEs
  - ✓ 10-month rate cases
  - ✓ Monthly fuel adjustment trackers (PSCR/GCR)
  - ✓ Constructive ROEs
- **Supportive incentives enhanced w/ 2023 Michigan Energy Law**
  - ✓ Energy efficiency incentives
  - ✓ FCM adder on PPAs
- **Appointed commissioners**
  - ✓ Commissioner Shaquila Myers (appointed July 2025)

2025

Electric

- ✓ Mar. 21st: Order $176M[a], 9.9% ROE U-21585
- Jun. 2nd: Filed $460M, 10.25% ROE U-21870

Gas

- June 25th: Revised $217M, 10.25% ROE U-21806
- By Oct. 16th: Expected Order U-21806

Renewable Energy Plan (REP)

- By Sep. 15th: Expected Order U-21816

Highlights

- ✓ Storm expense deferral approved
- ✓ Independent 3rd party distribution audit supports Electric Reliability Roadmap
- Support for gas infrastructure (~95% capital)

Presentation endnotes are included after the appendix.

. . . provides constructive outcomes and forward-looking visibility.

Financial Results & Outlook . . .

YTD 2025 Results	Amount	Commentary
Adjusted EPS	$1.73	Well-positioned to deliver

2025 Full-Year Outlook

Adjusted EPS Guidance	$3.54 – $3.60	Toward the high end
Annual Dividend Per Share (DPS)	$2.17	Up 11¢

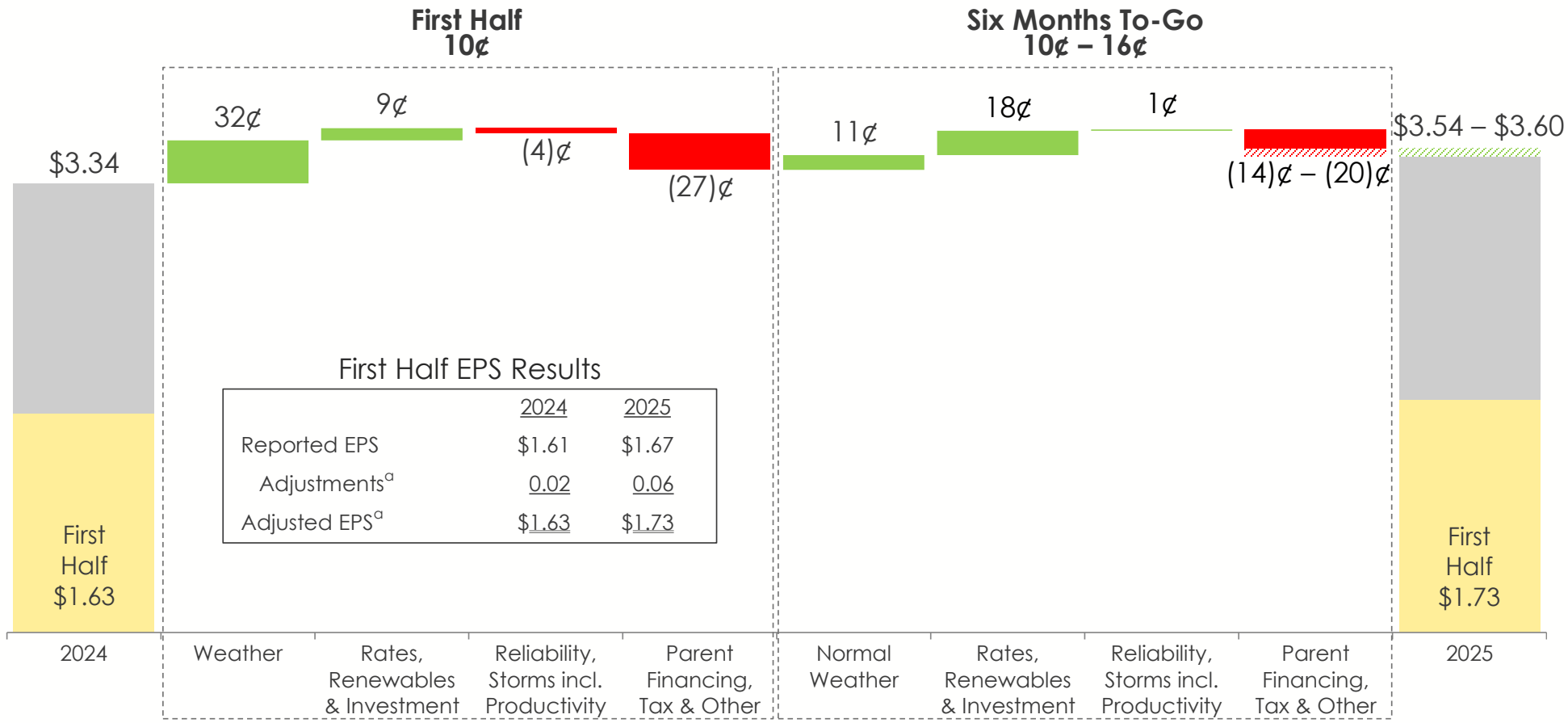
Long-Term Outlook

Adjusted EPS Growth	+6% to +8%	Toward the high end
Dividend Payout Ratio	~60% payout over time	Consistent DPS growth
Utility Capital Plan ($B)[a]	$20	Up $3 vs. prior plan

Presentation endnotes are included after the appendix.

. . . on track to deliver in 2025 and beyond.

2025 Adjusted EPS . . .



Presentation endnotes are included after the appendix.

. . . continued confidence toward the high end.

Strong Balance Sheet . . .

Consumers Energy	S&P	Moody's	Fitch
Senior Secured	A	A1	A+
Commercial Paper	A-2	P-2	F-2
Outlook	Stable	Stable	Stable
CMS Energy			
Senior Unsecured	BBB	Baa2	BBB
Junior Subordinated	BBB-	Baa3	BB+
Outlook	Stable	Stable	Stable
Last Review	**Dec. 2024**	**May 2025**	**Mar. 2025**

Key Strengths

- ✓ **Forward-looking recovery**
- ✓ **Constructive rate construct**
- ✓ **Strong operating cash flow generation**
- ✓ **100% fixed rate debt**
- ✓ **Hybrid debt (w/ equity credit)**
- ✓ **Limited near-term maturities**

. . . maintains credit metrics and solid investment-grade ratings.

2025 Planned Financings . . .

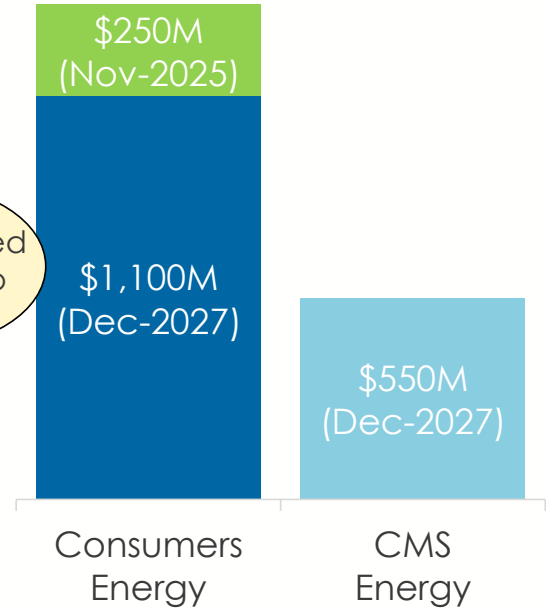
Financings

	Plan ($M)	YTD ($M)
Consumers Energy:		
First Mortgage Bonds	$1,125	$1,125 ✓
CMS Energy:		
New Debt Issuances	$1,270	$1,000
Planned Equity	Up to $500	--
Retirements (incl. term loans):		
Consumers Energy	None	--
CMS Energy	$850	$600

~$350M priced favorably to Plan

Existing Facilities

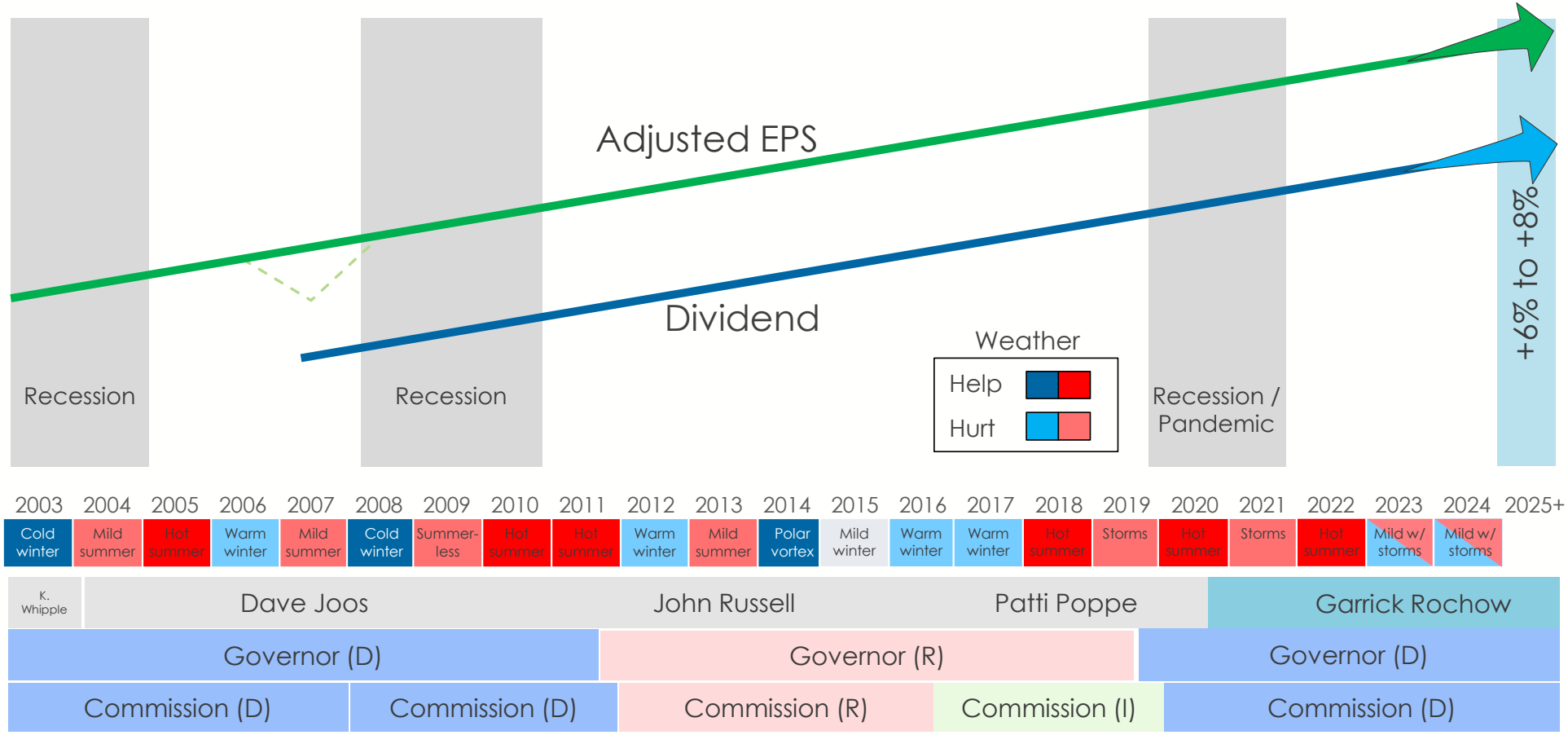
~$2.7B[a] of net liquidity



Presentation endnotes are included after the appendix.

. . . fund customer investments and provide ample liquidity.

Industry-Leading Financial Performance . . .



. . . for over two decades, regardless of conditions.

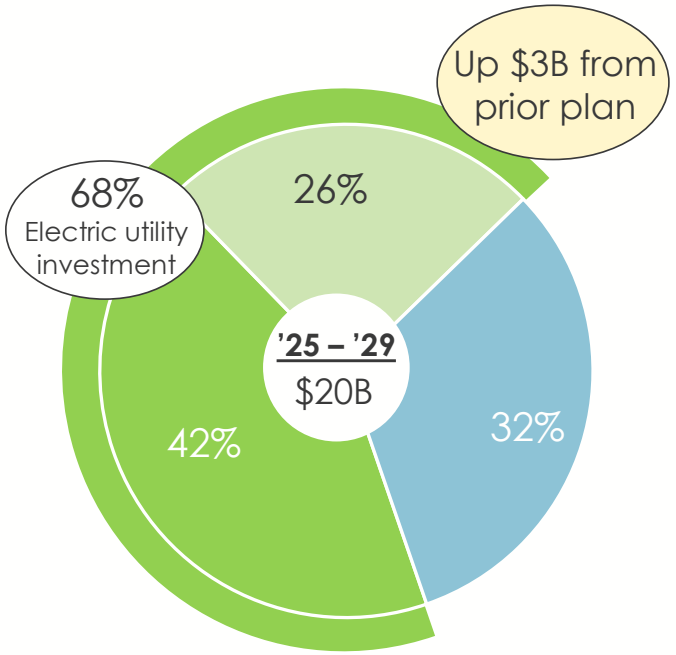
Q&A

Thank You!

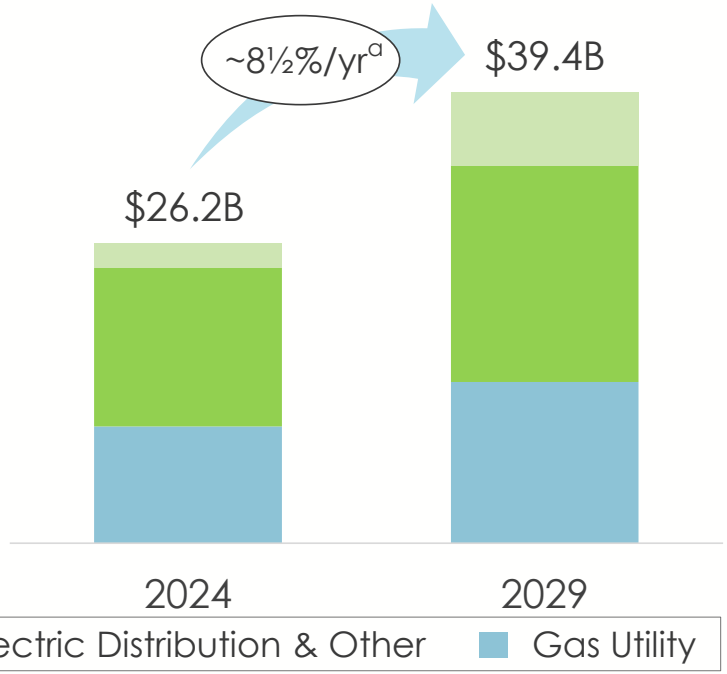
Appendix

Updated Customer Investment Plan . . .

New Utility Investment Plan



Rate Base Growth



Non-Rate Base Earnings[b]

- ✓ ~$20M pre-tax for FCM by 2029
- ✓ ~$60M/yr pre-tax for Energy Efficiency incentive
- ✓ NorthStar – DIG re-contracting opportunities

Presentation endnotes are included after the appendix.

. . . delivers benefits for customers and investors.

Endnotes

Presentation Endnotes

Slide 3: [a]UBS Research, 2025 state rankings and D.C.

Slide 5: [a]$5B estimate reflects preliminary estimate

Slide 6: [a]Assumptions are based on pre-existing safe harbor provisions

Slide 7: [a]$176M order includes a $22M surcharge related to distribution investments made in 2023 above prior approved levels

Slide 8: [a]$20B utility capital investment plan (2025-2029), up $3B from prior plan (2024-2028)

Slide 9: [a]Adjusted EPS; see GAAP reconciliation

Slide 11: [a]$1,870M in unreserved revolvers + $815M of unrestricted cash; excludes cash unavailable for debt retirement, such as cash held at NorthStar

Slide 15: [a]Assumes $26.2B rate base in 2024, $39.4B in 2029, CAGR [b]Over plan period years 2025-2029

CMS Energy provides historical financial results on both a reported (GAAP) and adjusted (non-GAAP) basis and provides forward-looking guidance on an adjusted basis. During an oral presentation, references to "earnings" are on an adjusted basis. All references to net income refer to net income available to common stockholders and references to earnings per share are on a diluted basis. Adjustments could include items such as discontinued operations, asset sales, impairments, restructuring costs, business optimization initiative, major enterprise resource planning software implementations, changes in accounting principles, voluntary separation program, changes in federal and state tax policy, regulatory items from prior years, unrealized gains or losses from mark-to-market adjustments, recognized in net income related to NorthStar Clean Energy's interest expense, or other items. Management views adjusted earnings as a key measure of the company's present operating financial performance and uses adjusted earnings for external communications with analysts and investors. Internally, the company uses adjusted earnings to measure and assess performance. Because the company is not able to estimate the impact of specific line items, which have the potential to significantly impact, favorably or unfavorably, the company's reported earnings in future periods, the company is not providing reported earnings guidance nor is it providing a reconciliation for the comparable future period earnings. The adjusted earnings should be considered supplemental information to assist in understanding our business results, rather than as a substitute for the reported earnings.

GAAP Reconciliation

CMS ENERGY CORPORATION
Reconciliation of GAAP Net Income to Non-GAAP Adjusted Net Income
(Unaudited)

	In Millions, Except Per Share Amounts			
	Three Months Ended		**Six Months Ended**	
	6/30/25	**6/30/24**	**6/30/25**	**6/30/24**
Net Income Available to Common Stockholders	$ 198	$ 195	$ 500	$ 480
Reconciling items:				
Other exclusions from adjusted earnings**	5	2	8	6
Tax impact	(1)	(*)	(2)	(1)
State tax policy change	12	-	12	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income – non-GAAP	$ 214	$ 197	$ 518	$ 485
Average Common Shares Outstanding - Diluted	299.1	298.5	299.0	297.9
Diluted Earnings Per Average Common Share				
Reported net income per share	$ 0.66	$ 0.65	$ 1.67	$ 1.61
Reconciling items:				
Other exclusions from adjusted earnings**	0.01	0.01	0.02	0.02
Tax impact	(*)	(*)	(*)	(*)
State tax policy change	0.04	-	0.04	-
Voluntary separation program	-	-	-	*
Tax impact	-	-	-	(*)
Adjusted net income per share – non-GAAP	$ 0.71	$ 0.66	$ 1.73	$ 1.63

* Less than $0.5 million or $0.01 per share.
** Includes restructuring costs and business optimization initiative.

CMS ENERGY CORPORATION
Reconciliation of GAAP Net Income to Non-GAAP Adjusted Net Income
by Quarter
(Unaudited)

In Millions, Except Per Share Amounts

	2025		2024			
	1Q	2Q	1Q	2Q	3Q	4Q
Net Income Available to Common Stockholders	$ 302	$ 198	$ 285	$ 195	$ 251	$ 262
Reconciling items:						
Electric utility and gas utility	*	4	4	2	*	*
Tax impact	(*)	11	(1)	(*)	(*)	(*)
NorthStar Clean Energy	3	1	-	-	-	-
Tax impact	(1)	(*)	-	-	-	-
Corporate interest and other	-	-	-	-	-	-
Tax impact	-	(*)	-	-	-	-
Disposal of discontinued operations (gain) loss	-	-	-	-	-	(*)
Tax impact	-	-	-	-	-	*
Adjusted Net Income – Non-GAAP	$ 304	$ 214	$ 288	$ 197	$ 251	$ 262
Average Common Shares Outstanding – Diluted	299.1	299.1	297.2	298.5	298.8	298.7
Diluted Earnings Per Average Common Share	$ 1.01	$ 0.66	$ 0.96	$ 0.65	$ 0.84	$ 0.87
Reconciling items:						
Electric utility and gas utility	*	0.01	0.01	0.01	*	*
Tax impact	(*)	0.04	(*)	(*)	(*)	(*)
NorthStar Clean Energy	0.01	*	-	-	-	-
Tax impact	(*)	(*)	-	-	-	-
Corporate interest and other	-	-	-	-	-	-
Tax impact	-	(*)	-	-	-	-
Disposal of discontinued operations (gain) loss	-	-	-	-	-	(*)
Tax impact	-	-	-	-	-	*
Adjusted Diluted Earnings Per Average Common Share – Non-GAAP	$ 1.02	$ 0.71	$ 0.97	$ 0.66	$ 0.84	$ 0.87

* Less than $0.5 million or $0.01 per share.

U-21859 | August 4, 2025
MNSC Hearing Exhibits
Ex MEC-48 | Source: U21859-MNSC-DCC-3.3
Page 1 of 1

MPSC Case No.: U-21859
Requester: MNSC
Question No.: MNSC-DCC-3.3
Respondent: Justin Bieber
Page: 1 of 1

QUESTION
Refer to Bieber rebuttal, p. 16 line 21 to p. 17 line 3. Identify the specific costs or categories of cost that you believe can be directly assigned to data centers or other large load customers.

RESPONSE:
The referenced section of my rebuttal testimony refers to facilities that are used exclusively by a single customer or group of customers. An example of such facilities could be a dedicated customer substation or a radial line that interconnects a customer to a dedicated customer substation.

As discussed in my direct testimony, Consumers' tariff allows the Company to charge a monthly extraordinary facilities charge or to require Contributions in Aid of Construction ("CIAC") when extraordinary facilities are required to interconnect a customer. Requiring non-refundable CIAC for such facilities is effectively a direct assignment of those costs.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Ex Parte Approval of Certain Amendments to Rate GPD.

Case No. U-21859

PROOF OF SERVICE

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

Name/Party	E-mail Address
ALJ Katherine E. Talbot	Talbotk@michigan.gov
Counsel for Consumers Energy Company Anne M. Uitvlugt Kelly Hall Bret A. Totoraitis	Mpsc.filings@cmsenergy.com Anne.uitvlugt@cmsenergy.com Kelly.hall@cmsenergy.com Bret.totoraitis@cmsenergy.com
Counsel for MPSC Staff David W. Isakson Amit T. Singh Adam M. Cozort Cherie Shea	isaksond@michigan.gov singha9@michigan.gov cozorta1@michigan.gov sheac1@michigan.gov
Attorney General Dana Nessel Lucas Wollenzien Michael E. Moody	ag-enra-spec-lit@michigan.gov wollenzienl@michigan.gov Mmoody2@michigan.gov
Consultants for Attorney General Dana Nessel Michael Deupree Taylor Deshotels Marcelo Gonzalez	michaeldeupree@acadianconsulting.com taylordeshotels@acadianconsulting.com marcelogonzalez@acadianconsulting.com
Counsel for Data Center Coalition Michael G. Oliva Nikhil Vijaykar Justin Bieber Kevin Higgins Lucas Fykes Travis Murray Shana Ramirez Alicia Zaloga	moliva@fosterswift.com nvijaykar@keyesfox.com jbieber@energystrat.com khiggins@energystrat.com lucas@datacentercoalition.org tmurray@keyesfox.com Shana.Ramirez@ethree.com azaloga@keyesfox.com

Association of Businesses Advocating Tariff Equity Stephen A. Campbell Michael J. Pattwell James Dauphinais Jessica York	 scampbell@clarkhill.com mpattwell@clarkhill.com jdauphinais@consultbai.com jyork@consultbai.com
Counsel for The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar Daniel Abrams Alondra Estrada Katie Toolen	mpscdocket@elpc.org dabrams@elpc.org aestrada@elpc.org KToolan@elpc.org
Counsel for Switch, LTD Valeria J.M. Brader	ecf@rivenoaklaw.com valerie@rivenoaklaw.com
Counsel for Michigan Energy Innovation Business Council, et al Justin K. Ooms Laura A. Chappelle Timothy J. Lundgren Lydia Lubbers	 jkooms@varnumlaw.com lachappelle@varnumlaw.com tjlundgren@varnumlaw.com lmlubbers@varnumlaw.com

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

Date: August 8, 2025

By: _____

Digitally signed by Natasha Fowles
Date: 2025.08.08 11:27:54 -04'00'

TROPOSPHERE LEGAL, PLC
Counsel for MNSC

Natasha Fowles, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4900
Email: natasha@troposphere legal.com