STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

PUBLIC DIRECT TESTIMONY

OF

CHRISTINA J. HAJJ

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF CHRISTINA J. HAJJ

Line No.

Q1. What is your full name, business address, and by whom are you employed?

A1. My name is Christina J. Hajj (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am the Director of Business Planning and Development (BP&D) – Strategy and Corporate Development (S&CD) and I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from the University of Miami with a Bachelor of Arts degree in International/Global Studies and English, Creative Writing. I received my Master's degree in Public Policy from the University of Michigan.

Q4. What is your professional experience?

A4. I began my career in various public service roles, including serving as a District Aide for the State of Florida House of Representatives, a Legislative Aide for the State of Florida Senate, an Education Volunteer for the United States Peace Corps, and a Research Associate for the Center for Defense Management Research at the Naval Postgraduate School. In 2013, I joined DTE Electric as a Policy Analyst in Corporate and Government Affairs and have since held various positions, including Senior Policy Analyst, Senior Strategist, Manager of Public Policy, Manager of Electric Strategy and Special Projects, Manager of Long-Term Generation Strategy, and, currently, Director of BP&D – S&CD.

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In 2016, I became Manager of Public Policy, where I led the Company's public policy strategy efforts on key energy and regulatory issues, including supporting the analysis and implementation of Michigan's 2016 energy law. In that role, I also developed policy positions and testimony for the Company's leadership to testify before the Michigan legislature on various energy policy issues. In 2019, I transitioned to Manager of Electric Strategy and Special Projects, leading the development of the DTE Electric strategic plan and supporting Company efforts around business and regulatory initiatives. In 2020, I moved to the role of Manager of Long-Term Generation Strategy, where I was responsible for developing the Company's long-term generation strategy and regulatory approach. In that role, I led the strategic development of the Company's 2022 Integrated Resource Plan (IRP) filing and supported the associated modeling and technical efforts. During this time, I was also an Advisory Council Member and Contributor to the Roosevelt Project Industrial Heartland Case Study through Massachusetts Institute of Technology (MIT)'s Center for Energy and Environmental Policy Research. In 2021, I was part of the Detroit Cohort for the Young American Leaders Program at Harvard Business School. I also supported policy analysis and implementation efforts related to Michigan's 2023 energy law. I assumed my current role as Director of BP&D – S&CD in 2023.

Q5. What are your current duties and responsibilities?

A5. As the Director of BP&D – S&CD, I am responsible for the Long-Term Generation Strategy, Resource Planning and Transmission Modeling, and Electric Strategy and Special Projects teams. In this role, I lead a multi-disciplinary team responsible for developing the Company's long-term electric generation plan with a primary focus

Line No.

on the 2026 IRP filing. This effort is foundational to reliably transitioning the Company's generation fleet from coal to cleaner energy and achieving the State's clean energy requirements.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. No. I have not sponsored testimony before the MPSC.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to provide an overview of DTE Electric's 2026 IRP filing, including the Company's Clean Energy Plan (CEP), its requests for Certificates of Necessity (CON), and the relationship of the 2026 IRP filing to the Company's concurrently filed Amended Renewable Energy Plan (REP) in Case No. U-22057. Specifically, my direct testimony will:

- Introduce the other DTE Electric witnesses sponsoring testimony in this proceeding and summarize the topics addressed in their testimony;
- Provide an overview of the Company's 2026 IRP Proposed Course of Action (PCA) and the associated requests for approval;
- Outline the applicable statutory and regulatory framework established under Sections 6s and 6t of 2016 Public Act (PA) 341, as amended by 2023 PA 231, MCL 460.6t and MCL 460.6s, including the Commission's orders in Case Nos. U-21867 and U-21570 establishing the applicable Michigan Integrated Resource Planning Parameters (MIRPP), IRP Filing

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Requirements, and CEP Filing Requirements, and Case No. U-15896 regarding CON Filing Requirements;

- Describe the principal requirements of Michigan's 2023 energy laws relevant to the IRP, including the Clean Energy Standard (CES) and the Renewable Portfolio Standard (RPS) established by 2023 PA 235, MCL 460.1051 and MCL 460.1028, and how the PCA accounts for those requirements;
- Summarize prior Commission orders in DTE Electric regulatory proceedings that impact this filing;
- Demonstrate compliance with all applicable statutory and regulatory requirements, filing requirements, and Commission orders associated with this proceeding;
- Summarize the Company's 2022 IRP in Case No. U-21193 and the resulting settlement agreement (Settlement Agreement) approved by the Commission on July 26, 2023, subsequent industry changes, and the Company's progress since approval of that Settlement Agreement;
- Provide an overview of the Company's 2026 IRP process and results, including the planning process, stakeholder engagement, scenarios and sensitivities, modeling results, and the rationale supporting selection of the PCA;
- Provide an overview of the resources for which the Company is seeking cost pre-approval under MCL 460.6t(11), including the 125 MW [redacted] (Solar PPA), the 138 MW Michigan Power Cogeneration facility, and capital costs associated with the demand response (DR) CoolCurrents program in this proceeding;

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- Introduce the Company's requests under MCL 460.6s for three CONs for each of the two proposed Combined Cycle Gas Turbine (CCGT) generation facilities, the Livingston County project and Monroe County project, each of which is designed to be Carbon Capture and Storage (CCS)-ready, including certificates addressing the need for power, whether each proposed facility represents the most reasonable and prudent means of meeting that need, and pre-approval of the estimated capital costs and financing plan for each CCGT facility;
- Outline the Company's implementation plan for the PCA, with a focus on the first five years following Commission approval of this IRP; and
- Recommend, based on the analyses and evidence presented by the Company's sponsoring witnesses, that the Commission approve DTE Electric's 2026 IRP application and grant the relief requested therein, including approval of the IRP and CEP, issuance of the requested CONs, approval of the Company's statewide energy storage target, and the other requested approvals including associated cost pre-approvals, and find that the PCA is the most reasonable and prudent means for the Company to meet its customers' future capacity and energy needs.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-1	DTE Electric IRP Application Requirements Cross Reference Table
A-1.1	DTE Electric Clean Energy Plan Requirements

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1		A-1.2	DTE Electric Certificate of Necessity Requirements
2		A-1.3	DTE Electric Recommendations from Other Orders
3		A-1.4	DTE Electric Alignment of Planning Objectives and IRP Criteria
4		A-1.5	DTE Electric Alignment of Planning Objectives and CON Criteria
5		A-1.6	DTE Electric Public Outreach Report
6		A-1.7	NDA DTE Electric Cost Pre-Approval Requests
7		A-1.8	DTE Electric PCA Implementation Plan
8			
9	**Q9.**	**Were these exhibits prepared by you or under your direction?**	
10	A9.	Yes, they were.	
11			
12	**Q10.**	**How is your testimony organized?**	
13	A10.	After introducing witnesses, my testimony consists of the following eight parts:	
14		Part I	PCA Overview
15		Part II	IRP Statutory & Regulatory Framework
16		Part III	Prior IRP Context & Industry Changes
17		Part IV	IRP Planning Objectives, Process, and Stakeholder Engagement
18		Part V	IRP Modeling Results & Selection of PCA
19		Part VI	Requests for Commission Approval
20		Part VII	Implementation of the PCA
21		Part VIII	Conclusion
22			
23	**Q11.**	**Who presents evidence in support of the Company's 2026 IRP filing and the**	
24		**relief requested in this proceeding?**	

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A11. The Company presents evidence in support of its 2026 IRP filing, including its IRP and CEP, CON requests, and other requested relief, through 21 witnesses, including myself, as described below.

Table 1 Witness Overview

	Witness	Scope of Testimony
1	**Shayla D. Manning**	Provides an overview of the IRP framework, planning process, modeling assumptions, scenarios, and risk assessments. She also presents the IRP results and details the 2026 PCA.
2	**Jason T. Busse**	Supports the financial, cost, and operating assumptions used in IRP modeling, including impacts of the One Big Beautiful Bill Act (OBBBA). He also evaluates peaker economics and performs stochastic economic risk analysis.
3	**Ryan C. Pratt**	Discusses peaker retirements, Monroe Power Plant gas conversion, nuclear strategy, and emerging technologies. He also describes the 2025 All-Source Request for Proposal (RFP) process, resource selections, and related CON and cost pre-approval requests.
4	**Shawn D. Burgdorf**	Explains Midcontinent Independent System Operator (MISO) resource adequacy requirements, capacity resources, purchase power agreements (PPAs), demand response, and effective capacity import limit (ECIL) and local reliability requirements applicable to MISO Local Resource Zone 7 and Michigan. He also discusses ancillary services and the market impacts of the proposed CCS-ready CCGT projects.
5	**Justin J. W. Brooks**	Supports the resource adequacy analysis conducted by PowerGEM for the Company's 2026 IRP filing.
6	**Frank J. Sirwaitis**	Presents the Company's 2026-2046 sales, demand, system output, and customer count forecasts. He explains key modeling assumptions, including electrification, electric vehicles (EVs), energy waste reduction (EWR), distributed generation (DG), large load forecasting, and forecasting alignment between the IRP and the Distribution System Plan (DSP).
7	**Markus B. Leuker**	Describes the Company's current and planned demand response (DR) programs and evolving DR framework. He also supports IRP assumptions and the request for DR capital cost pre-approval.

Line No.	Witness	Scope of Testimony
8	**Margaret E. Guillaumin**	Provides information on existing fossil-fueled, nuclear, and energy storage assets. She also supports operation and maintenance (O&M) and capital cost assumptions for Monroe Power Plant, Greenwood Energy Center, and peaker generation assets.
9	**David Swiech**	Describes fuel supply arrangements, fuel cost forecasts, and fuel-related assumptions used in the IRP. He also supports fuel cost estimates for existing and future generation resources.
10	**Kevin L. Bilyeu**	Discusses RPS requirements and renewable resources included in the IRP. He supports renewable resource forecasts and modeling assumptions for utility-scale wind and solar.
11	**Jason R. Kupser**	Reviews the Company's EWR programs and performance. He also supports the EWR assumptions and savings levels used in IRP modeling.
12	**Husaninder Singh**	Discusses coordination between the DSP and IRP, including Conservation Voltage Reduction (CVR) and Volt-Var Optimization (VVO) programs and avoided transmission and distribution (T&D) values. He also discusses how peaking generation supports distribution reliability and Distribution Operations' role in the Company's peaker analysis.
13	**Jablan Djordjevic**	Supports transmission planning analyses related to the PCA and CON requests. He discusses grid studies, transmission upgrades, storage benefits, capacity import limits (CIL), and transmission impacts on resource planning.
14	**Barry J. Marietta**	Reviews environmental regulations affecting Company resources and compliance considerations. He also presents emissions, environmental justice (EJ), health impact analyses, and other environmental considerations supporting the IRP and CON requests.
15	**Harry O. Stansell Jr.**	Provides details on the proposed CON resources, including locations, technology selection, design, costs, operations, and CCS implementation. He also demonstrates the reasonableness of the associated capital cost estimates, and supports the proposed O&M plans, including underlying cost assumptions.
16	**Michael E. Banks**	Describes development of the proposed CCS-ready CCGT projects, including engineering, procurement, and construction (EPC) strategy, permitting, workforce planning, risks, and construction schedules. He supports

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	Witness	Scope of Testimony
		the prudence and reasonableness of the development approach.
17	**Matthew Lind**	Explains the EPC cost estimates for the proposed CON projects and benchmarks them against similar utility projects. He concludes that the estimated costs are within a reasonable range when fairly compared to similar projects.
18	**Priya Machi**	Analyzes customer rate and affordability (also referred to as "energy burden calculations") impacts of the PCA across customer classes. She provides the calculation of the rate impact by customer class and energy burden calculation for the PCA both with and without the load and cost impacts from the large load customers, consistent with the contracts filed in Case Nos. U-21990 and U-22058.
19	**Terri L. Schroeder**	Discusses the Company's energy storage portfolio and planned energy storage projects supporting the PCA. She also reviews energy storage policy requirements, industry challenges, and cost-effectiveness considerations.
20	**Theresa M. Uzenski**	Supports the Company's proposed financing costs associated with the CCS-ready CCGT projects.

Q12. What is the relationship between the Company's 2026 IRP, CEP, requests for CONs, and its concurrently filed Amended REP in Case No. U-22057?

A12. Unless otherwise specified, the testimony, exhibits, and workpapers submitted in this proceeding support the Company's 2026 IRP filing, including its IRP and CEP and requests for CONs. The resource plan reflected in the Company's PCA is consistent with the RPS and also provides the basis for the Company's concurrently filed Amended REP in Case No. U-22057, which presents the Company's plan for complying with the RPS.

PART I: PCA OVERVIEW

Q13. What key factors influenced the development of the PCA?

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A13. Four primary factors influenced the development of the PCA including state and federal laws and requirements, reliability needs, customer demand, and resource economics and technology availability.

- State and federal laws and requirements: The PCA must comply with Michigan's RPS, CES, EWR requirements, statewide energy storage target, and other applicable federal and state regulatory requirements.
- Reliability needs: The Company plans to retire Monroe Power Plant Units 3 and 4 in 2028 and Units 1 and 2 in 2032, consistent with the Settlement Agreement in its 2022 IRP (Case No. U-21193). The Company is also proposing to retire the Superior Peaking Station in 2032. The PCA must ensure that sufficient replacement resources are available before these retirements occur, must meet MISO reliability requirements, and must be resource adequate.
- Customer demand: The PCA load forecast incorporates the approximately 2.4 GW of contracted large load customer demand associated with Oracle America Cloud Services LLC (OACS) and Google LLC (Google).[1] It also incorporates EV adoption, DG, and other forecasted changes in customer energy needs. The PCA also evaluates a range of load growth sensitivities, including sensitivities addressing prospective large load growth, to evaluate how changing customer demand could affect resource planning over the 20-year planning horizon.
- Resource economics and technology availability: The PCA evaluates potential resource options based on factors including cost, commercial maturity, development timelines, siting and permitting requirements,

[1] Consistent with MPSC Case Nos. U-21990 and U-22058. See Q78.

Line No.

interconnection needs, supply chain considerations, and operational characteristics.

Q14. What is the Company's PCA and how was it determined?

A14. DTE Electric's final PCA, referred to as PCA in my testimony, is the Company's proposed resource plan for reliably and affordably serving customers over the 20-year planning period from 2027 through 2046 while supporting Michigan's clean energy transition and complying with applicable laws, rules, and regulations. The PCA builds upon the starting point planning resources and assumptions used in the Company's IRP analysis and incorporates the incremental resource additions, retirements, and other changes identified in the Company's proposed plan. Witness Manning explains the development of the starting point, the incremental changes reflected in the PCA, and the modeling and analyses supporting the Company's selection of the PCA.

The PCA reflects a balanced, all-of-the-above approach to resource planning. It continues the Company's commitment to exit coal through the phased retirement of the Monroe Power Plant; expands renewable energy, energy storage, and demand-side resource portfolios; maintains and grows nuclear generation output, adds firm dispatchable natural gas generation, and preserves flexibility to incorporate emerging technologies as they become commercially available and cost-effective.

No single resource can meet all customer needs under all conditions. Accordingly, the PCA relies on a diverse portfolio of resources capable of providing energy,

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capacity, operational flexibility, and resource adequacy throughout the 20-year planning period.

Based on the Company's modeling, reliability assessments, risk analyses, competitive procurement activities, and evaluation of statutory requirements, the PCA represents the most reasonable and prudent plan to reliably meet customers' future energy and capacity needs. The PCA is compliant with Michigan's RPS, CES, EWR requirements, and statewide energy storage target.

Q15. Can you summarize the resources and resource actions included in the PCA?

A15. Yes. From 2027 through 2046, the PCA builds upon the Company's existing and approved resources and other applicable planning assumptions and incorporates the following principal resource retirements, supply and demand-side resource additions.

Resource Retirements

- Completes the Company's exit from coal through the phased retirement of the Monroe Power Plant, with Units 3 and 4 retiring in 2028 and Units 1 and 2 retiring in 2032. These retirements continue the transformation of DTE Electric's capacity mix from 62% coal in 2005 to no coal capacity beginning in 2033; and
- Retires the Superior Peaking Station located in Superior Township, Washtenaw County, Michigan, in 2032.

Line No.

Supply-Side Resources

- Adds a total of 15 GW of renewable energy, supporting compliance with Michigan's RPS requirements of 50% renewable energy in 2030 and 60% beginning in 2035;
- Adds a total of 4.5 GW of energy storage, exceeding DTE Electric's proportional share of the statewide energy storage target and supporting the integration of higher levels of renewable energy. The energy storage additions include long-duration energy storage (LDES) resources capable of providing more than 10 hours of capacity and supporting the integration of renewables;
- Upgrades nuclear generating capacity through a proposed 177 MW extended power uprate (EPU) at the Fermi 2 Nuclear Power Plant; and
- Integrates approximately 2.2 GW of additional natural gas generation, including the purchase of an existing 138 MW generating facility in Michigan and the construction of two CCS-ready CCGT facilities, approximately 1,400 MW and 700 MW, with planned commercial operation dates of 2031 and 2032, respectively, with CCS planned to be installed by 2035 to support compliance with Michigan's CES.

Demand-Side Resources

- Maintains an aggregate DR portfolio of 638 MW that remains relatively constant over the planning period while reflecting changes in the forecasted contributions of individual programs, including an increased contribution from the CoolCurrents program supported by planned investments from 2028 through 2030;

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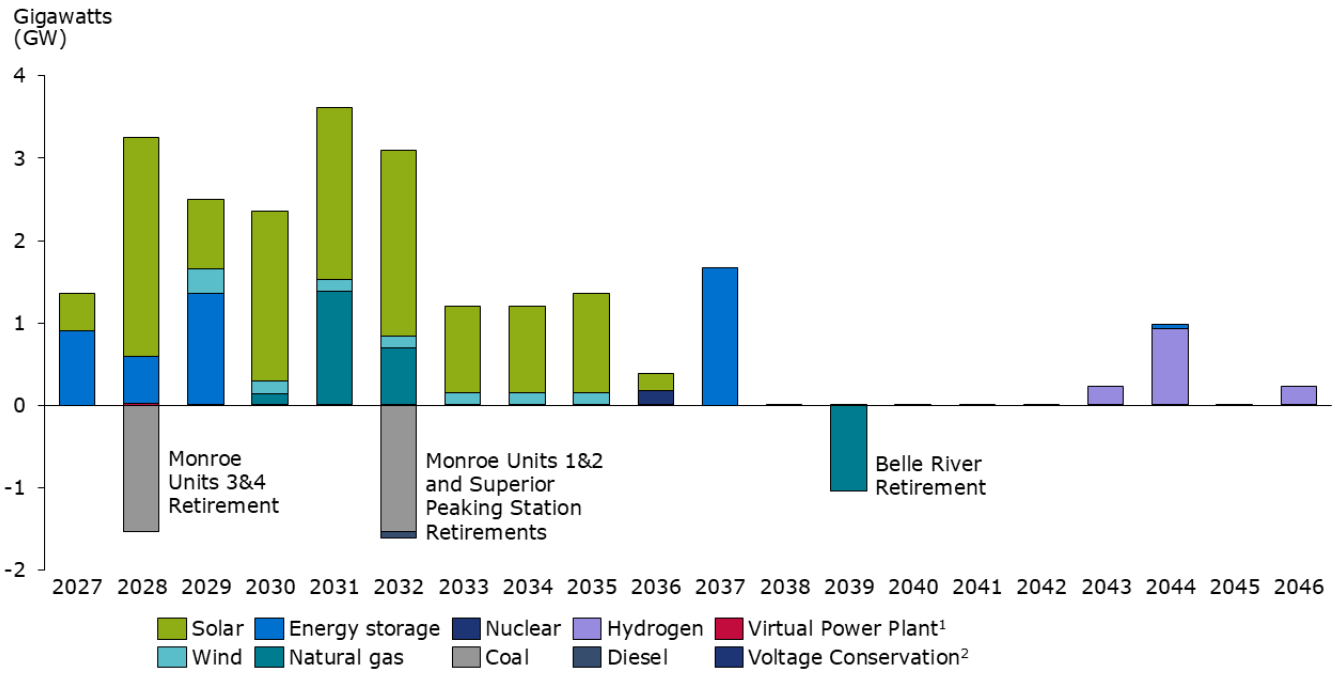
- Continues and expands the Company's EWR programs, helping customers use energy more efficiently and lower overall demand while meeting applicable statutory requirements throughout the planning period, with annual EWR program savings in 2046 projected to be approximately 20% more than in 2025;
- Includes approximately 73 MW of new virtual power plant (VPP) capacity within the resource portfolio, which will operate as a coordinated DR and energy storage resource. The VPP will aggregate participating customer-sited resources to shift peak demand, provide flexible capacity during periods of system need; and
- Builds on the Company's previous commitment to CVR/VVO deployment by adding approximately 17 MW of these technologies to optimize voltage levels, reduce energy consumption, lower system demand, and improve distribution system efficiency.

Q16. What is the Company's proposed resource plan over the 20-year study period from 2027 through 2046?

A16. The PCA establishes the Company's long-term resource plan over the 20-year planning period, as seen in Figure 1. The plan builds upon the starting point planning resources and assumptions used in the IRP analysis and transitions the generation portfolio by replacing retiring coal-fired and peaking generation resources with a diverse portfolio of supply-side and demand-side resources that reliably and affordably meet customers' energy and capacity needs. The PCA also maintains the operation of existing resources that continue to support reliability and provide customer value.

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Figure 1 – Starting Point Resources and PCA Additions



1. Virtual Power Plant capacity ranges from 0-16 MW annually through the plan period, totaling 73 MW
2. Voltage Conservation, or Conservation Voltage Reduction (CVR) and Volt-Var Optimization (VVO), ranges from 0-2 MW annually through the plan period, totaling 17 MW

Q17. Can you summarize the Company's PCA during the first five years of the plan, from 2027 through 2031?

A17. Yes. The first five years of the plan focus on meeting 2030 RPS and energy storage target statutory requirements and implementing the near-term resources necessary to support the phased retirement of the Monroe Power Plant, with Units 3 and 4 retiring in 2028 and Units 1 and 2 retiring in 2032, which will complete the

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Company's exit from coal. Building on the starting point, during this period, the PCA:

- Retires the Monroe Power Plant Units 3 and 4 in 2028, removing approximately 1.5 GW of coal-fired generation from the Company's portfolio;
- Adds approximately 8.7 GW of renewable energy and meets the 50% RPS requirement in 2030 as well as positions the Company to meet the 60% RPS requirement in 2035;
- Continues the integration of an incremental approximately 2.8 GW of energy storage, enough to exceed the Company's proportional share of the statewide energy storage target of 1,127 MW in 2029;
- Acquires an existing 138 MW Michigan generating facility in 2030 to provide additional firm dispatchable generation;
- Includes the proposed 1,400 MW CCS-ready CCGT facility with a planned commercial operation date in 2031, representing the first phase of a planned total of approximately 2.1 GW of new CCS-ready CCGT capacity;
- Maintains 2.0% EWR savings at the levels described in Case No. U-21681 through 2028, and continues 1.5% annual EWR savings thereafter, meeting Michigan's statutory requirements, as discussed by Witness Kupser;
- Maintains an aggregate DR portfolio that remains relatively constant while reflecting changes in the forecasted contributions of individual programs, including the planned increase in CoolCurrents capacity supported by the 2028 through 2030 investments described by Witness Leuker;
- Advances VPP deployment, achieving 23 MW by the end of 2031; and
- Adds 10 MW of CVR/VVO by the end of 2031.

Line No.

These near-term actions are important because they set the stage for a reliable exit of coal and the retirement of Superior Peaking Station in 2032, and the continued march toward 2035 and 2040 RPS and CES compliance requirements.

Q18. Can you summarize the Company's PCA during the second five years of the plan, from 2032 through 2036?

A18. Yes. The second five years of the plan mark the completion of DTE Electric's transition away from coal and the establishment of a diverse resource portfolio consisting of renewable energy, energy storage, demand-side resources, nuclear generation, and natural gas-fired generation. During this period, the Company completes the resource transitions needed to satisfy reliability requirements and support compliance with Michigan's RPS and CES targets. Specifically, the PCA:

- Adds 6.4 GW of renewable energy to meet and maintain the 60% RPS requirement in 2035 and support the CES targets;
- Complies with Michigan's CES requirements, including the 80% clean energy requirement in 2035;
- Completes the retirement of the Monroe Power Plant with Units 1 and 2 in 2032, removing the final 1.5 GW of coal-fired generation from the Company's resource portfolio;
- Retires the 76 MW Superior Peaking Station in 2032;
- Includes the second proposed approximately 700 MW CCS-ready CCGT facility with a planned commercial operation date in 2032, completing the addition of approximately 2.1 GW of new CCS-ready CCGT capacity;
- Installs CCS on both proposed CCGT facilities in 2035. The facilities are designed to capture and permanently store at least 90% of their carbon

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dioxide emissions in support of CES requirements as further described by Witness Stansell;

- Expands the Fermi 2 Nuclear Power Plant facility through the proposed 177 MW EPU in 2036;
- Continues expanding VPP capacity by approximately 15 MW; and
- Adds an approximate 6 MW of CVR/VVO by the end of 2036.

Collectively, these actions complete the Company's transition away from coal-fired generation, replace retiring capacity with a diverse portfolio of clean and dispatchable energy resources, and positions the Company to maintain reliability and resource adequacy to meet customers' energy and capacity needs while complying with Michigan's RPS, CES, and energy storage requirements through the mid-2030s.

Q19. Can you summarize the Company's PCA during the last ten years of the plan, from 2037 through 2046?

A19. Yes. The final ten years of the plan reflect the continued evolution of the Company's generation portfolio as it maintains compliance with Michigan's CES while preserving flexibility to respond to changing technologies, customer needs, state and federal laws and requirements, and market conditions. Given the long-term nature of this portion of the plan, the PCA during these years is likely to be further refined through future IRP filings. During this period, the PCA:

- Maintains compliance with Michigan's 60% RPS;
- Complies with Michigan's 80% CES and meets the 100% clean energy requirement in 2040;

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- Adds approximately 1.7 GW of the Company's first LDES resources capable of supporting the system for periods longer than 10 hours;
- Retires the Belle River Power Plant, approximately 1 GW[2] in 2039;
- Continues expanding VPP capacity by approximately 36 MW;
- Reduces carbon dioxide emissions by approximately 90% from 2005 levels by 2040;
- Integrates hydrogen (H_2) combustion turbines as needed to support MISO's reliability requirements; and
- Preserves flexibility to evaluate and incorporate emerging low- and zero-carbon technologies as they become commercially available, executable, and cost effective.

The final ten years of the PCA provide flexibility to adapt to changing circumstances while maintaining reliability and compliance with applicable statutory requirements. The Company recognizes that technology availability, customer demand, state and federal laws, and market conditions will continue to evolve over time. Consistent with prior IRPs, the Company will periodically reassess its resource needs and refresh its long-term outlook to reflect changing conditions and opportunities.

Q20. Why are the timing and sequencing of resource retirements and additions a critical component of the PCA?

[2] Belle River Power Plant has 1,270 MW of summer net capacity, of which 81.39% (1,034 MW) is owned by DTE Electric and 18.61% (236 MW) is owned by the Michigan Public Power Agency

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A20. The timing and sequencing of resource retirements and additions is critical to maintaining reliability and resource adequacy. Because generation, energy storage, transmission interconnections, and other major infrastructure investments can require years to develop and place in service, replacement resources must be identified, procured, and available prior to retiring existing resources.

The PCA aligns new resource additions with the planned retirements of the Monroe Power Plant Units 1 and 2 and the Superior Peaking Station to maintain resource adequacy, comply with MISO reliability requirements, preserve sufficient energy and capacity resources to meet customer demand, and support an orderly transition to a cleaner and more diverse generation portfolio while continuing to provide safe, reliable, and affordable electric service.

Q21. What are the forecasted CO_2 emissions reductions over the planning period?

A21. The PCA continues the transformation of the Company's generation portfolio and results in reductions in CO_2 emissions over the planning period. As shown in Figure 2, the PCA reduces carbon emissions by more than 90% from 2005 levels. This is consistent with the Company's 2022 IRP commitments and continues progress toward the Company's decarbonization journey.

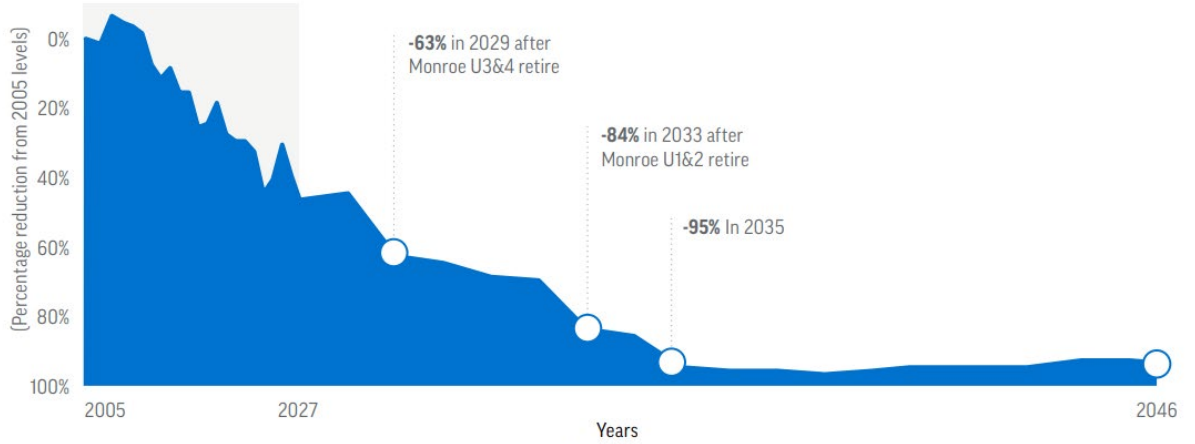
The majority of the forecasted decline in annual CO_2 emissions between 2028 and 2035 occurs by 2033, before the planned CCS installation at the proposed CCGT facilities. The major driver of these reductions is the phased retirement of the Monroe Power Plant and the resulting exit from coal in the Company's generation portfolio, the continued addition of renewable energy and energy storage, the

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addition of more efficient natural gas-fired generation, and other changes reflected in the PCA. The modeled implementation of CCS at the proposed CCGT facilities provides additional emissions reductions beginning in 2035.

The PCA therefore reduces emissions while maintaining the diverse mix of resources needed to reliably and affordably serve customers through the planning period. Witness Marietta discusses the Company's emissions projections, including the magnitude and timing of the CO_2 emissions reductions and the resource changes that drive them.

Figure 2 – DTE Electric Carbon Emissions Reductions from 2005-2046



[1] *CO_2 emission reductions are shown relative to 2005 emission levels based on MIRPP Scenario 1, projected CO_2 emissions are shown relative to the 2005 baseline and historical data through 2025; data for 2026 is a projection. The graph shows we achieve at least a 65% CO_2 reduction in 2028, 85% in 2032, and 90% by 2040, compared to 2005 levels*

Q22. What are the key benefits of the PCA?

A22. The PCA provides reliability, customer, environmental, economic, and technology advancement benefits while supporting compliance with Michigan's energy policies and maintaining affordability for customers. In addition, the PCA is

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projected to lower customer costs by $3.5 billion Net Present Value of Revenue Requirements (NPVRR) as supported by Witness Manning and lower average residential rates by 4% in comparison to the resource portfolio approved in the Company's 2022 IRP as presented by Witness Machi.

Specifically, the PCA provides the following benefits:

Reliability benefits

- Maintains a reliable and resource adequate portfolio through a diverse mix of renewable generation, natural gas generation, energy storage, nuclear generation, VPPs, and demand-side resources.
- Adds significant renewable generation and energy storage while bringing firm dispatchable generation into service before resource retirements occur in 2032.
- Aligns resource additions with planned retirements to ensure continued compliance with MISO reliability requirements and maintain reliable electric service to customers.
- Supports resource adequacy and system reliability during extreme weather events and other stressed system conditions through a balanced portfolio with complementary resource capabilities.

Customer benefits

- The PCA is projected to cost $3.5B less than the portfolio approved in the Company's 2022 IRP while continuing to meet reliability, environmental, and statutory requirements.
- Results in projected average rates over the study period below the 2022 PCA across all customer classes (see Witness Machi).

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- Manages long-term customer costs through competitive procurement processes, continued utilization of existing resources, and continued and appropriately expanded demand-side programs.
- Reduces exposure to potential capacity market volatility, emergency market purchases, and unplanned resource development risks through the orderly sequencing of resource additions and retirements.
- Maintains a diverse resource portfolio that helps balance reliability, affordability, and environmental objectives over the planning period.

Environmental benefits

- Completes the Company's transition away from coal through the retirement of the Monroe Power Plant in 2032.
- Maintains compliance with Michigan's RPS and CES requirements.
- Reduces CO_2 emissions by more than 90% from 2005 levels and continues the Company's decarbonization journey.
- Substantially reduces other fleet air emissions as the generation portfolio transitions away from coal. In 2033, compared to 2027, projected NOx emissions are approximately 87% lower, SO_2 emissions are approximately 98% lower, carbon monoxide emissions are approximately 84% lower, particulate matter emissions are approximately 34% lower, and projected fleet mercury and lead emissions fall to zero (see Witness Marietta);
- Provides environmental and public health benefits associated with the retirement of the Monroe Power Plant and Superior Peaking Station, both located near EJ communities.

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Economic benefits

- Supports continued investment in Michigan through the development of new resources sited in the state.
- Creates construction and long-term employment opportunities associated with the development and operation of new resources.
- Utilizes Michigan labor and contributes to local tax bases across the state.
- Supports workforce transition planning associated with coal plant retirements through developing and implementing strategic workforce planning initiatives.

Technology advancements

- Positions the Company and Michigan to advance deployment of renewable energy, energy storage, and innovative grid technologies.
- Introduces advanced technologies, including LDES, VPPs, the proposed 177 MW EPU at the Fermi 2 Nuclear Power Plant, and CCS at the proposed CCS-ready CCGT facilities.
- Preserves flexibility to integrate emerging low- and zero-carbon technologies, including H_2-fueled combustion turbines and other advanced technologies, as they become commercially available, executable, and cost-effective.

Q23. How does the PCA build upon the commitments and outcomes established in the Company's 2022 IRP?

A23. The PCA demonstrates that the Company has successfully executed and advanced the strategic direction established in its 2022 IRP. The 2022 IRP provided a pathway to exit coal, expand renewable energy and energy storage resources, invest

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No.

in demand-side resources, evaluate peaking resource retirements, and continue assessing emerging low- and zero-carbon technologies. The proposed PCA is the next step in executing and refining that plan.

Since approval of the 2022 IRP in Case No. U-21193, the Company has made progress in implementing (as described in Part III) or advancing the Settlement Agreement, including:

- Bringing a total of 3.7 GW of renewable energy online by the end of 2027, with plans to accelerate the 2022 IRP target of 15,400 MW;
- Bringing a total of 1.1 GW of four-hour energy storage online by the end of 2027;
- Ceasing coal-fired operations at the Belle River Power Plant, completing its conversion to a natural gas peak demand resource by the end of 2026;
- Maintaining the planned retirement schedule for Monroe Power Plant Units 3 and 4 in 2028 and Units 1 and 2 in 2032;
- Completing an evaluation of the Company's peaking resources, leading to the proposed retirement of the Superior Peaking Station in 2032;
- Achieving more than 2% EWR savings annually from 2023 to 2025;
- Continuing commitment to customer programs, including maintaining EWR and DR programs, implementing the forecasted changes in the contributions of individual DR programs, as well as continued deployment of CVR/VVO; and
- Continuing to evaluate low- and zero-emission technologies, including LDES, nuclear generation, H_2 combustion turbines, and CCS.

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The PCA builds on this demonstrated success and continues the strategic direction established in the 2022 IRP while updating the long-term resource plan to reflect today's evolving planning environment. Since the Commission approved the 2022 IRP Settlement Agreement, Michigan has enacted additional clean energy requirements, customer demand forecasts are changing, and MISO has updated its reliability planning framework. The PCA addresses these developments while remaining consistent with the Company's long-term objectives of maintaining reliability and affordability, complying with statutory, regulatory, and MISO requirements, and continuing the transition to a cleaner and more diverse generation portfolio.

Q24. Can you summarize what Commission approval the Company is seeking as part of this request?

A24. Yes. The Company is seeking the following action from the Commission:

- Determination that the Company complied with the statutory requirements, modeling parameters, filing requirements, and other orders and guidance applicable to the IRP, CEP, RPS, and CONs;
- Approval of the IRP and determination that the PCA is the most reasonable and prudent means of meeting the Company's energy and capacity needs;
- Determination that the PCA satisfies applicable CES and RPS target requirements and provides the foundation for the concurrently filed Amended REP;
- Determination that the PCA supports and meets the Company's portion of the statewide energy storage target;

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- Determination that the Company complied, to the extent applicable, with the competitive procurement guidelines;
- Determination that the Company does not have a capacity need in the next five years pursuant to the Public Utility Regulatory Policies Act (PURPA);
- Pre-approval of capital costs ($21.3 million) for the planned 2028-2030 CoolCurrents investments, which are necessary to maintain and achieve the program's forecasted capacity contribution within the existing DR portfolio and are planned to commence within three years of the Commission's order approving the IRP;
- Pre-approval of the Solar PPA project, financial compensation mechanism (FCM) request, and associated annual costs that commence in 2030;
- Pre-approval of capital costs to purchase the Michigan Power Cogeneration facility ($130 million), that commence within three years of the Commission's approval of this IRP;
- Approval of three certificates of necessity for the Livingston County project, including findings that (i) the power to be supplied as a result of the proposed construction, investment, or purchase is needed, (ii) the size, fuel type, and other design characteristics of the proposed electric generation facility represent the most reasonable and prudent means of meeting that power need, and (iii) the estimated purchase or capital costs of ($3.9 billion), and the financing plan for the proposed electric generation facility will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c); and
- Approval of three certificates of necessity for the Monroe County project, including findings that (i) the power to be supplied as a result of the

Line No.

proposed construction, investment, or purchase is needed, (ii) the size, fuel type, and other design characteristics of the proposed electric generation facility represent the most reasonable and prudent means of meeting that power need, and (iii) the estimated purchase or capital costs of ($2.5 billion), and the financing plan for the proposed electric generation facility will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).

PART II: IRP STATUTORY & REGULATORY FRAMEWORK

Q25. Can you describe the statutory and regulatory frameworks that apply to the Company's 2026 IRP filing?

A25. Yes. The statutory and regulatory frameworks that apply to this filing include MCL 460.6t and MCL 460.6s, as applied to the Company's 2026 IRP and requests for CONs, and MCL 460.1051 as applied to its CEP. In addition, the MPSC orders in Case Nos. U-21570 and U-21867 that established the applicable MIRPP, IRP Filing Requirements and CEP requirements apply to this filing, as well as Case No. U-15896 regarding CON filing requirements.

In addition to the IRP, CEP, and CON statutory and regulatory requirements, this filing addresses requirements arising from certain DTE Electric proceedings, including the 2022 IRP Settlement Agreement in Case No. U-21193 approved by the Commission on July 26, 2023, the Amended REP Settlement Agreement in Case No. U-21662 approved by the Commission on May 15, 2025, the DTE Electric Rate Case in Case No. U-21860 approved on February 19, 2026, and special contract approvals in Case No. U-21990.

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Statutory IRP Framework Under MCL 460.6t

Q26. What is the statutory and regulatory framework for IRPs?

A26. MCL 460.6t establishes the statutory framework for integrated resource planning in Michigan. Under MCL 460.6t(3), an integrated resource plan must provide a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, the utility's generation reliability requirements, and applicable state and federal reliability and environmental requirements over the term of the plan.

MCL 460.6t(5) also requires the IRP to address a broad range of planning considerations, including:

- Long-term sales and peak demand forecasts;
- Existing and potential resources for meeting future energy and capacity needs;
- Compliance with Michigan's renewable energy plan requirements, clean energy requirements, EWR measures, and energy storage target;
- Projected costs, rate impacts, and affordability;
- Environmental compliance and projected greenhouse gas emissions and other pollutants; and
- Applicable environmental justice analyses.

MCL 460.6t(1)(f) directs the Commission to establish modeling scenarios and assumptions that each electric utility should include in addition to their own scenarios and assumptions when developing its IRP. MCL 460.6t(3) also directs the Commission to establish applicable IRP filing requirements. MCL 460.6t(20)

Line
No.

requires an electric utility to file an application for review of its IRP not later than five years after the effective date of the most recent Commission order approving a plan, plan amendment, or plan review.

Q27. What are the statutory criteria for evaluating an IRP?

A27. MCL 460.6t(8) requires the Commission to approve an IRP if it meets the findings specified in MCL 460.6t(8). The Commission must first determine that the proposed IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. In making that determination, the Commission considers whether the plan appropriately balances all the following factors:

- Resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement;
- Compliance with applicable state and federal environmental regulations;
- Competitive pricing;
- Reliability;
- Commodity price risks;
- Diversity of generation supply;
- Whether the proposed levels of peak load reduction and EWR are reasonable and cost-effective;
- Affordability; and
- Overall cost-effectiveness in providing utility service.

In addition, MCL 460.6t(8) requires the Commission to make additional determinations, including that:

Line
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- To the extent practicable, construction or investment in new or existing capacity resources in Michigan uses a workforce composed of Michigan residents, except as otherwise provided by statute for certain resources located in counties bordering another state;
- Construction, construction maintenance, or rehabilitation of applicable capacity resources in Michigan satisfies the statutory apprenticeship, prevailing wage and fringe benefit, and, to the extent permitted by law, project labor agreement or collective bargaining agreement requirements;
- The plan is consistent with the state's renewable energy plan requirements and goals, CES requirements, EWR requirements, and energy storage target; and
- The plan promotes environmental quality and public health and reasonably mitigates adverse effects on human health due to power generation, with priority given to mitigating impacts and prioritizing benefits for communities disproportionately impacted by pollution and other environmental harms; and the plan meets the IRP content requirements of MCL 460.6t(5).

Q28. What timeline does the statute establish for the Commission's review and approval of an IRP after it is filed?

A28. MCL 460.6t(7) requires the Commission to review the IRP in a contested case proceeding. No later than 300 days after the IRP is filed, the Commission must state whether it recommends changes to the plan. If the Commission does not recommend changes, it must issue a final, appealable order approving or denying the plan. If the Commission recommends changes, the statute provides an

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opportunity for comments within 15 days and submissions of a revised IRP within 30 days, and the Commission must issue a final, appealable order no later than 360 days after the IRP was filed.

IRP Filing Requirements & MIRPP

Q29. What are the MPSC's IRP filing requirements?

A29. In its December 18, 2025 order in Case Nos. U-21867 and U-21570, the Commission approved updated requirements for the content and supporting documentation of utility IRP filings. These filing requirements supplement the statutory IRP content requirements established by MCL 460.6t(5) and specify the analyses, information, testimony, exhibits, workpapers, and modeling files that utilities must provide in support of an IRP application. The Company's testimony, exhibits, and workpapers identify how the applicable IRP filing requirements are addressed in this filing.

Q30. What are the MPSC's MIRPP?

A30. As updated in Case Nos. U-21867 and U-21570, the MIRPP requires utilities to evaluate specified scenarios and sensitivities so that resource plans can be assessed under a range of possible future conditions using common planning assumptions. A scenario is a set of assumptions representing a possible future, such as assumptions regarding commodity prices, technology costs, load growth, and environmental regulations. A sensitivity changes a particular assumption or variable within a scenario to evaluate how that change affects the modeling results.

Q31. How does the MIRPP apply to this filing?

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A31. The Company modeled the two scenarios under the MIRPP and a Company-developed Reference scenario, together with applicable sensitivities. Witness Manning describes the MIRPP scenarios and sensitivities evaluated, the modeling performed, and the resulting resource portfolios.

Q32. Did the Company conduct a rate impact and affordability impact analysis in this proceeding?

A32. Yes. The Company conducted a rate impact and affordability impact analysis consistent with the requirements established by the December 18, 2025 Commission Order in Case Nos. U-21867 and U-21570. Specifically, Case Nos. U-21867 and U-21570 require the utilities to conduct a rate impact analysis that identifies "[t]he average rate impact by customer class (i.e., residential, C&I, etc.). The analysis shall include the Utility's most recently approved base rate revenue requirement for full-service customers, a forecast of the revenue requirement growth based on a projected inflation factor, the percentage of the production cost allocations assignable to each customer class, based on the prior approved rate case, and the estimated delta revenue requirement of the PCA to determine the average rate impact."

Additionally, the term "affordability impact analysis" shall mean "energy burden calculation," which aligns with the applicable requirements that "[t]he utility shall show the affordability impact of the PCA as compared to its previously approved build plan. The utility shall describe its methodology and data sources including but not limited to income-based segmentation, publicly available data used, any limitations of data availability, proxies such as demographics or housing data, etc.

Line No.

Example methodology is in Appendix 2. If any identified income range is expected to increase an energy burden at or above 6%, the utility shall provide a discussion of available assistance, EWR programs and measures, or other options that could aid in mitigating the expected increased energy burden for the areas identified."

Witness Machi further describes the rate and affordability impact analyses in her testimony.

Q33. What environmental and public health information must the Company provide in support of this IRP?

A33. The Commission's IRP filing requirements require the Company to address environmental compliance, emissions, environmental justice, and public health. This includes projected emissions information; compliance with applicable local, state, and federal environmental laws, regulations, and rules; progress toward state, federal, and utility-announced carbon-reduction goals; and the environmental justice and health-impact analyses necessary to support the Michigan Department of Environment, Great Lakes, and Energy's (EGLE's) advisory opinion under MCL 460.6t(7)(a)(iii).

Witness Marietta presents the Company's environmental regulation, emissions, EJ, and health impact analyses. Witness Manning presents the scenarios, sensitivities, portfolio modeling, and modeling results used to develop and evaluate the resource plans considered in this IRP.

Line No.

CEP Requirements

Q34. Per MCL 460.1051(1), what is the CES?

A34. The CES was enacted as part of 2023 PA 235, which established a requirement for electric providers to achieve a clean energy portfolio of at least 80% from 2035 through 2039, and 100% starting in 2040 and each year after.

Q35. How does the CES affect the Company's long-term resource planning?

A35. The Company incorporated these requirements into its IRP planning process and sought resources that met or could meet the "clean energy systems" definition in its most recently conducted 2025 All-Source RFP.

Q36. How are "clean energy systems" defined?

A36. Per MCL 460.1003(i), clean energy systems are defined as, "an electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:

i. Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

ii. Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of environment, Great Lakes, and energy determines, through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section

Line
No.

51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

iii. Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

iv. Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision."

Q37. What is the CEP?

A37. The CEP, or Clean Energy Plan, is the plan required by MCL 460.1051 for demonstrating how an electric provider intends to comply with Michigan's Clean Energy Standard. The CES requires electric providers to achieve a clean energy portfolio of at least 80% in 2035 through 2039 and 100% beginning in 2040. For electric utilities whose rates are regulated by the Commission, MCL 460.1051(2)(a) requires the CEP to be submitted as part of the utility's IRP.

Q38. How do the CEP requirements apply to this filing?

Line
No.

A38. Because MCL 460.1051 requires electric utilities whose rates are regulated by the Commission to submit a CEP as part of their IRP, the Company's 2026 IRP filing includes both the Company's proposed IRP and its CEP. The CEP illustrates how the Company intends to achieve the CES milestones over the planning period using the resources and implementation strategy reflected in the IRP, while continuing to meet customers' energy and capacity needs reliably, affordably, and prudently over the planning horizon.

Consistent with the CEP filing requirements, the Company developed the IRP and CEP using common assumptions, inputs, load forecasts, modeling analyses, and resource planning results. Rather than duplicate information presented elsewhere in the IRP filing, the Company identifies the testimony, exhibits, and workpapers that apply to both the IRP and CEP. Accordingly, the CEP's supportive showings are presented across the testimony and exhibits of applicable Company witnesses, as referenced in Exhibit A-1.1.

Witness Manning explains how the CES was incorporated into the Company's resource planning analysis, identifies the resource types included in the CES compliance calculation, presents the results of the Company's evaluation of the PCA's compliance with the CES, and sponsors Exhibit A-2.5, the Company's completed CEP template. Witness Pratt explains how the Michigan Power Cogeneration facility satisfies the applicable facility characteristics under MCL 460.1003(i)(iii) and how the Company's overall CEP provides the functional equivalence plan contemplated by that provision. Witness Marietta presents the projected greenhouse gas emissions reductions resulting from the PCA that support

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the CEP. Taken together, this testimony and supporting evidence demonstrate how the integrated portfolio of resources and actions reflected in the PCA meets the applicable CES requirements and supports approval of the Company's overall CEP.

RPS Requirements

Q39. What is the RPS?

A39. 2023 PA 235 amended Michigan's renewable energy law and established updated RPS targets codified in MCL 460.1028. MCL 460.1028(1) requires electric providers to achieve a renewable energy credit (REC) portfolio of at least 15% through 2029, 50% starting in 2030 through 2034, and 60% in 2035 and each year thereafter.

Q40. How does the RPS affect the Company's long-term resource planning?

A40. The RPS affects the Company's long-term resource planning by requiring the Company to plan for sufficient eligible renewable energy resources and RECs to achieve the REC portfolio requirements based on the applicable percentage of retail electricity sales established by the statute. The Company incorporates existing and approved renewable resources into the IRP starting point and accounts for the additional renewable resources needed to support RPS compliance when developing its PCA. Witness Bilyeu describes the renewable resources and assumptions incorporated into the IRP, the Company's projected REC requirements, and the renewable resources included in its PCA to support RPS compliance. Witness Manning further explains how the RPS was addressed in the Company's modeling and development of its PCA.

Line
No.

Statewide Energy Storage Target

Q41. What is the statewide energy storage target?

A41. The statewide energy storage target was established by 2023 PA 235 and is codified in MCL 460.1101. MCL 460.1101(1) establishes a statewide target of 2,500 MW of energy storage by December 31, 2029. The statute requires each electric provider to meet its proportional share of that statewide target, with the share calculated based on the provider's annual average contribution to Michigan's in-state retail electric peak load over the relevant five-year period. The Commission established the methodology for calculating each provider's proportional share and provided related reporting guidance in Case No. U-21571.

Q42. How do the energy storage targets apply to the Company?

A42. MCL 460.1101(2) requires the Company to demonstrate compliance with its plan under MCL 460.1101(1) for meeting its proportional share of the statewide energy storage target as part of its IRP. Using the methodology approved in Case No. U-21571, MPSC Staff calculated the Company's proportional share of the statewide target in the annual Statewide Energy Storage Target Calculation filed in Case No. U-21907. Consistent with that requirement and the Commission's IRP filing requirements, the Company's 2026 IRP filing identifies DTE Electric's proportional share of the statewide target and describes how the Company's existing, approved, and planned energy storage resources meet that requirement. Witness Schroeder identifies the Company's allocated share, describes the energy storage resources supporting compliance, and explains that the Company expects its approved energy storage resources to exceed its allocated share of the statewide

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target. Witness Manning further describes how energy storage was evaluated in the Company's resource planning analysis and incorporated into the PCA.

EWR Requirements

Q43. What are the EWR requirements?

A43. The EWR requirements were updated by 2023 PA 229, which amended Michigan's energy law and revised the energy savings requirements for electric and natural gas providers. Beginning in 2026, MCL 460.1077(1) requires an electric provider's EWR programs to collectively achieve annual incremental energy savings equivalent to 1.5% of total retail electricity sales in megawatt-hours in the preceding year. MCL 460.1077(2) separately establishes a goal that an electric provider's EWR programs collectively achieve annual incremental energy savings equivalent to 2% of the preceding year's total retail electricity sales in megawatt-hours, with an average measure life of at least eight years, and requires that goal to be included in the electric provider's IRP modeling scenarios.

2023 PA 229 also requires the filing of new customer energy optimization plans, which include required EWR plans and may include optional efficient electrification measures.

Q44. How do the EWR requirements apply in this proceeding?

A44. EWR is a demand-side resource that reduces customer energy consumption and affects the Company's forecasted energy and capacity needs. The EWR requirements are reflected in the Company's load forecast, modeling assumptions,

Line No.

resource need assessment, and portfolio evaluation. Therefore, EWR is an integral component of the Company's long-term planning analysis and PCA.

The Company incorporated the EWR savings levels reflected in its approved 2026-2029 EWR Plan and the long-term savings levels reflected in its approved 2022 IRP into the load forecast. The Company also evaluated additional EWR savings levels through the IRP modeling and sensitivity analyses. Witness Sirwaitis explains how EWR savings are reflected in the Company's load forecast, Witness Manning explains how EWR was evaluated in the IRP modeling, and Witness Kupser describes the Company's EWR programs, savings assumptions, and implementation of the EWR levels reflected in the PCA.

CON Statutory and Regulatory Requirements

Q45. What is the statutory and regulatory framework for Certificates of Necessity?

A45. CON requirements are established in MCL 460.6s and apply to qualifying construction of electric generation facilities, significant investments in existing electric generation facilities, purchases of existing electric generation facilities, or long-term power purchase agreements. In addition, MCL 460.6t(13) requires a utility to seek a CON under MCL 460.6s when a capacity resource subject to MCL 460.6t(12) involves construction of an electric generation facility of 225 MW or more, or the addition of generation units totaling 225 MW or more at an existing facility.

Under MCL 460.6s(3), the Commission may issue separate certificates determining that: (1) the power to be supplied as a result of the proposed construction,

Line
No.

investment, or purchase is needed; (2) the size, fuel type, and other design characteristics of the generation facility, or the terms of a power purchase agreement, represent the most reasonable and prudent means of meeting that power need; and (3) the estimated purchase or capital costs of, and the financing plan for, the generation facility, or the price of the power purchase agreement, will be recoverable in customer rates, subject to MCL 460.6s(4)(c).

The Commission's CON filing requirements and instructions adopted in Case No. U-15896 specify the information that an application must include to support the requested statutory determinations, including evidence concerning the need for power, the proposed facilities, the reasonableness and prudence of the proposed resources, estimated costs and financing, alternatives considered, project development and implementation, and supporting workpapers and modeling files.

Q46. How do the CON requirements apply to this filing?

A46. The Company is seeking six CON approvals under MCL 460.6s associated with the proposed Livingston County project and Monroe County project, both of which are included in the Company's PCA. For each project, the Company requests that the Commission determine that: (1) the power to be supplied as a result of the proposed construction is needed; (2) the project's size, fuel type, and other design characteristics represent the most reasonable and prudent means of meeting that power need; and (3) the project's estimated capital costs and financing plan will be recoverable in customer rates, subject to MCL 460.6s(4)(c).

Line
No.

Witness Pratt describes the six requested CON approvals and explains how the proposed projects satisfy the applicable statutory requirements. Other Company witnesses provide the project-specific evidence required by MCL 460.6s and the Commission's CON filing requirements. For example, Witness Stansell provides supporting testimony concerning the CON projects' development, technical and operating characteristics, engineering and design, and estimated capital and O&M costs. Witness Banks describes the proposed CON projects and provides supporting evidence concerning their development, schedules, implementation risks, and permitting requirements.

The proposed projects consist of CCGT facilities designed to be CCS-ready. The Company seeks CON approval in this proceeding for the CCGT portions of the projects and does not seek approval of specific future CCS costs at this time.

Q47. Does Commission approval of the requested CONs replace the environmental permits and other governmental approvals required for the proposed Livingston County and Monroe County projects?

A47. No. Approval of the CONs would address the certificate determinations before the Commission, including the need for the power to be supplied by the proposed projects, whether each project's size, fuel type, and other design characteristics represent the most reasonable and prudent means of meeting that need, and the requested cost approvals. The Company must separately obtain the applicable environmental permits and other governmental approvals required to construct and operate each project. Those permitting authorities will determine the final permit-specific requirements and conditions under the laws and regulations they

Line No.

administer. Witness Marietta discusses the anticipated environmental requirements and permitting pathway for the proposed projects, and Witness Banks discusses project development and permitting activities.

Other Related Orders

Q48. What requirements did the Commission's order in Case No. U-21990 establish for the Company's 2026 IRP and related filings?

A48. The Commission's December 18, 2025 order in Case No. U-21990 conditionally approved special contracts between DTE Electric and Green Chile Ventures LLC (n/k/a Oracle America Cloud Services LLC or OACS),[3] consisting of a primary supply agreement and energy storage agreement. The order established requirements for the Company's subsequent IRP, CEP, Amended REP, EWR, and related filings. As applied to this proceeding, the Commission directed DTE Electric to include in its next IRP application, "a comparison of the resource requirements necessary to serve the company's load with and without the addition of the [OACS] load. This analysis should be completed by identifying the resources included in the PCA and testing their performance in the Michigan Integrated Resource Planning Parameters Scenario #2 base model or in the alternative company base model, and shall include the corresponding plan production cost, rate impact by customer class, and an affordability analysis as directed by the IRP Filing Requirements adopted in Case No. U-21867. The same analysis should then be performed by evaluating the PCA to serve the company's existing customers absent

[3] Green Chile Ventures LLC changed its name to Oracle America Cloud Services LLC after the Commission issued its December 18, 2025 order. Accordingly, the Commission's order refers to the customer as Green Chile Ventures LLC or GCV, while this filing refers to the customer by its current name, Oracle America Cloud Services LLC or OACS.

Line
No.

the [OACS] load. When removing the [OACS] load, the incremental renewable generation that is needed for RPS compliance with the [OACS] load identified in the company's REP and the storage that is expected to be developed pursuant to the ESA should also be removed. This comparison should illustrate [OACS's] overall impact on resource planning and illustrate any net impact to other customers' rates."[4]

The Commission also directed the Company to, "file an amended REP with its next IRP and (initial) CEP, and that application for an amended REP shall include a comparison of the resource requirements needed to comply with the RPS targets both with and without the [OACS] load and corresponding retail sales."[5]

Q49. How has the Company addressed the requirements of the Commission's order in Case No. U-21990 that apply to this proceeding?

A49. DTE Electric has addressed the requirements that apply to its 2026 IRP filing. Witness Manning presents the comparison of the resource requirements necessary to serve the Company's load with and without the addition of the OACS load. Witness Machi presents the corresponding rate impact by customer class and an affordability analysis required by the Commission's order. The Company is separately addressing the Amended REP requirements established by the Commission's order through its concurrently filed Amended REP in Case No. U-22057. Exhibit A-1.3 identifies where the requirements established by the

[4] MPSC Order in Case No. U-21990, December 18, 2025, pp. 35-36.
[5] MPSC Order in Case No. U-21990, December 18, 2025, p. 35.

Line No.

Commission's order that apply to this proceeding are addressed in the Company's filing.

Q50. Is the application, along with witness testimony, exhibits, and workpapers, consistent with the applicable statutory requirements, IRP filing requirements, MIRPP, CEP requirements, CON requirements, and other Commission orders governing this filing?

A50. Yes. The application, along with witness testimony, exhibits, and workpapers, is consistent with the applicable statutory requirements, IRP filing requirements, MIRPP parameters, CEP requirements, CON requirements, and other Commission orders governing this filing. See Exhibit A-1 DTE Electric IRP Application Requirements Cross Reference Table, Exhibit A-1.1 DTE Electric Clean Energy Plan Requirements, Exhibit A-1.2 DTE Electric Certificate of Necessity Requirements, and Exhibit A-1.3 DTE Electric Recommendations from Other Orders for the cross-reference tables identifying where all requirements are addressed in this filing.

Q51. Did the Company comply with all applicable statutes, orders, filing requirements, modeling parameters, and other applicable guidance relevant to this proceeding?

A51. Yes. The Company complied with all applicable statutes, orders, filing requirements, modeling parameters, and other applicable guidance relevant to this proceeding. See Exhibit A-1 DTE Electric IRP Application Requirements Cross Reference Table, Exhibit A-1.1 DTE Electric Clean Energy Plan Requirement, Exhibit A-1.2 DTE Electric Certificate of Necessity Requirements, and Exhibit A-

Line
No.

1.3 DTE Electric Recommendations from Other Orders for the cross-reference tables identifying where all requirements are addressed in this filing.

PART III: PRIOR IRP CONTEXT & INDUSTRY CHANGES

Prior IRP Context

Q52. When did the Company file its last IRP?

A52. The Company filed its last IRP (2022 IRP) with the Commission on November 3, 2022, in Case No. U-21193. Nearly nine months later, on July 26, 2023, the Commission approved the Settlement Agreement. As part of the Settlement Agreement, DTE Electric agreed to file its next IRP by December 2026.

Q53. What was the primary objective of the last IRP?

A53. The primary objective of the 2022 IRP was to reliably and affordably advance the Company's decarbonization targets. The plan focused on accelerating the retirement of coal generation, expanding its renewable energy and energy storage portfolios, and ensuring reliability through a balanced generation portfolio. The plan incorporated stakeholder engagement throughout its development.

Q54. Can you describe what was filed in Case No. U-21193 regarding the Company's 2022 IRP filing?

A54. Yes. The Company's 2022 IRP was built upon the foundation established in the 2019 IRP and continued to further advance its clean energy transition and commitments to reducing energy waste. As filed, the 2022 IRP covered a 20-year period (2023-2042) and proposed the adoption of an incremental 15,400 MW of renewable energy and 1,810 MW of battery energy storage systems, the retirement

Line
No.

of over 4,100 MW of coal-fired generation, the incorporation of demand-side management programs (EWR, DR and CVR/VVO), and the integration of reliable dispatchable generation from the conversion of the Belle River Power Plant from a coal-fired power plant to a natural gas peaking resource. The 2022 IRP advanced the Company's CO_2 emissions reduction goals by establishing a PCA that included a clear action plan and aggressive interim goals, achieving a 65% reduction in 2028, an 85% reduction in 2035, and a 90% reduction by 2040 from 2005 levels.

Over the 20-year study period, the Company's proposed 2022 IRP PCA included:

- 6,500 MW of solar energy;
- 8,900 MW of wind energy;
- 1,810 MW of battery energy storage systems;
- Ceasing coal-fired generation operations at the Belle River Power Plant and converting it from a coal-fired baseload power plant to a natural gas peaking resource in 2025 (Unit 1) and 2026 (Unit 2);
- Retiring the Monroe Power Plant Units 3 and 4 in 2028, and Units 1 and 2 in 2035;
- Incorporating the maximum amount of achievable EWR potential identified in the 2021 Michigan EWR Statewide Potential Study, an average of 1.5% per year over the study period[6];
- Deploying 38 MW of CVR/VVO; and
- Incorporating a 946 MW low- or zero-carbon, dispatchable resource in 2035 when the final two units (Units 1 and 2) of the Monroe Power Plant retire.

[6] Percentage represents non-standard program energy savings

Line
No.

Q55. Can you describe what was agreed upon in the Settlement Agreement for Case No. U-21193?

A55. Yes. The Settlement Agreement in Case No. U-21193, among many provisions, accelerated the retirement of Monroe Units 1 and 2, as well as renewable and energy storage builds initially proposed in the PCA. The PCA approved by the 2022 IRP Settlement Agreement included:

- 15,400 MW of renewables, with an accelerated development schedule of 400 MW of solar by 2030;
- 1,830 MW of battery energy storage systems, with an accelerated development schedule of 420 MW by 2030;
- Ceasing coal-fired generation operations at the Belle River Power Plant and converting it from a coal-fired baseload power plant to a natural gas peaking resource in 2025 (Unit 1) and 2026 (Unit 2);
- Retiring the coal-fired Monroe Power Plant Units 3 and 4 in 2028, and Units 1 and 2 in 2032;
- Retiring the River Rouge peakers (11 MW) and St. Clair diesel peaker (5 MW) in 2024;
- Targeting an average level of 2.0% energy savings from energy efficiency programs from 2023 through 2027;
- A 946 MW low- or zero-carbon, dispatchable resource in 2032 when the final two units (Units 1 and 2) of the Monroe Power Plant retire. The Settlement Agreement also required that the Company study a range of replacement technologies for this resource.

Line No.

The Settlement Agreement also accelerated the Company's previous CO_2 interim reduction goals to target 65% in 2028, 85% in 2032, and 90% by 2040.

In addition, the Settlement Agreement called for:

- Directing an additional $110 million to support income-qualified home energy efficiency programs, customer affordability programs and access to clean energy resources for the Company's most vulnerable customers;
- The Company enhancing its outreach and public engagement plan in its next IRP to focus more on overburdened communities as defined in MPSC Case No. U-18461;
- The Company committing to evaluating alternative retirement dates of 2030 and 2032 for the Monroe Power Plant; and
- DTE Electric committing to model various sensitivities for the replacement of Monroe Power Plant Units 1 and 2, updating the peaker analysis, and incorporating other key modeling elements into its next IRP.

Q56. Can you describe the key regulatory environment, modeling assumptions, and industry trends that informed the 2022 IRP?

A56. Yes. The development of the 2022 IRP occurred during a period of regulatory and energy industry changes. There were several changes in the industry including the Inflation Reduction Act (IRA), which helped improve the economics of clean energy technologies including solar, wind, nuclear, carbon capture and storage, and energy storage system resources. There were also changes to the MISO accreditation methodology, which transitioned toward the effective load carrying capability (ELCC) methodology, and the increasing resource adequacy concerns

Line No.

driven by the large amounts of retiring baseload generation. At the same time, the energy industry was faced with changes to load growth driven mainly by forecasted electrification, and the potential for emerging technologies that had not yet reached full commercialization. There was also some uncertainty in long-term load growth following the COVID-19 pandemic. Together, these factors created a planning environment that was focused on balancing affordability, reliability, and decarbonization while the industry was changing.

Q57. What role did low- and zero-emission emerging technologies play in the 2022 IRP?

A57. The evaluation of low- and zero-emission emerging technologies played an important role in the Company's 2022 IRP by supporting its objectives to balance affordability, reliability, and decarbonization and was further supported by the IRA. While the first half of the PCA's 20-year study period relied on known, commercially available technologies, additional technology solutions were needed to support a reliable, affordable path to further decarbonize. The Company recognized that as coal-fired generation retires and renewable resources make up a larger share of the generation portfolio, new low- and zero-emission emerging technologies would be needed to ensure reliability while advancing carbon reduction goals. Emerging technologies such as mid- to long-duration energy storage, small modular reactors (SMR), H_2, and CCS were some of the technologies considered to support DTE Electric's path to net zero emissions while maintaining reliability and affordability. At the time of the 2022 IRP, however, these technologies were limited or not yet commercially available. DTE Electric also recognized their costs and availability would likely change over the course of the

Line No.

study period as emerging technology development progressed. Accordingly, the 2022 IRP included a placeholder technology to reflect the potential role of low- and zero-emission emerging resources as part of the Company's long-term strategy to support a cleaner and more reliable plan.

Q58. Has the Company successfully implemented the 2022 IRP to date?

A58. Yes. The Company has successfully implemented several aspects of the 2022 IRP and is on track to continue building upon this success in the 2026 IRP. By the end of 2027, the Company will have successfully achieved the following:

- Developed a total of 3.7 GW of renewable energy;
- Developed 1.1 GW of energy storage systems;
- Converted Unit 1 at the Belle River Power Plant from coal to natural gas in 2025 and will fully convert the plant to a natural gas peaking plant by the end of 2026;
- Retired the River Rouge (11 MW) and St. Clair (5 MW) peakers in 2024; and
- Achieved 2.16% EWR in 2023, 2.07% in 2024, and 2.06% in 2025.

Q59. Which components of the Settlement Agreement in Case No. U-21193 are addressed in this IRP filing related to modeling?

A59. This filing addresses all requirements related to modeling that were established by the Settlement Agreement in Case No. U-21193 including:

1. Determining the EWR savings levels beyond 2027 through studying a range of potential levels as discussed by Witnesses Kupser and Manning;

Line
No.

2. Determining an approach to modeling DG as a resource in the IRP and seeking stakeholder feedback prior to conducting the IRP modeling as described by Witness Manning;
3. Developing an outreach and public engagement plan for the 2026 IRP that was focused on overburdened communities and began two years in advance of the 2026 IRP with the methods and results documented in this IRP as discussed in Part IV of my testimony;
4. Studying alternative retirement dates of 2030 and 2032 for Monroe Units 1 and 2 as discussed by Witness Manning;
5. Studying a range of possible replacement technologies for Monroe Units 1 and 2 as discussed by Witnesses Pratt and Manning;
6. Modeling MISO's seasonal construct as discussed by Witness Manning;
7. Refining energy storage system modeling and continuing to incorporate industry best practices as discussed by Witnesses Manning and Schroeder;
8. Conducting a natural gas conversion study of the Monroe Power Plant as discussed by Witness Pratt;
9. Considering the impacts on future capacity needs resulting from implementation of the two projects listed in the 2019 Michigan Capacity Import/Export Limit Expansion Study and other similar long-term transmission feasibility studies reviewed by MISO as discussed by Witness Manning;
10. Providing an updated peaker analysis that includes a study of the potential retirement dates, replacement cost of capacity and other peaker functionality, non-wire alternatives, and the impacts of peakers located near EJ communities as discussed by Witnesses Pratt and Singh;

Line
No.

11. Conducting a cold winter weather year Loss of Load Profile (LOLP) analysis, including an assessment of Expected Unserved Energy (EUE), and considering the risk of natural gas supply and renewable power supply issues as supported by Witnesses Manning and Brooks;
12. Developing reasonable projections for DR pilot programs that are likely to be adopted as ongoing programs as described by Witness Leuker;
13. Including Electric Vehicle managed charging and vehicle-grid integration as DR options as described by Witness Leuker;
14. Including an EJ agenda topic in a DTE Electric IRP technical stakeholder workshop for feedback, discussion, and recommendations on the approach to the EJ analysis, including, but not limited to, the threshold and indicators used and the marginal public health impact assessment as presented in Part IV of my testimony; and
15. Including the results of an EJ analysis for Michigan across various portfolios in the development of criteria for use in the Risk Assessment process (e.g., a portfolio metric evaluation) as supported by Witness Marietta.

Michigan Energy Policy Updates

Q60. What changes in Michigan energy policy have occurred since the Company's last IRP?

A60. Since the Company's last IRP, the State of Michigan enacted updates to the energy law that affects the energy policy and regulatory framework under which electric utilities develop IRPs. 2023 PA 229, 231, 233, and 235 amended several areas of Michigan energy law, including integrated resource planning, clean energy,

renewable energy, DG, energy waste reduction, energy storage, and the siting of certain renewable energy and energy storage projects. At a high level:

- 2023 PA 231 amended MCL 460.6t, the State's IRP statute, and updated the planning framework and requirements applicable to utility IRPs.
- 2023 PA 235 amended the Clean and Renewable Energy and Energy Waste Reduction Act and established new clean energy (MCL 460.1051), renewable energy (MCL 460.1028), and statewide energy storage requirements (MCL 460.1101), and updating DG (MCL 460.1003; MCL 460.1005; MCL 460.1173; and MCL 460.1177) requirements.
- 2023 PA 229 updated Michigan's EWR requirements (MCL 460.1071 through 460.1099).
- 2023 PA 233 established a process at the Commission for siting certain utility-scale renewable energy and energy storage facilities under specified circumstances (MCL 460.1221 through 460.1232).

These statutory changes are important to the Company's IRP because they affect both the requirements the Company must satisfy and the planning assumptions it must evaluate in developing its IRP.

Q61. How did the 2023 PA 231 affect the IRP process?

A61. 2023 PA 231 amended Section 6t of 1939 PA 3, MCL 460.6t, which governs integrated resource planning for rate-regulated electric utilities in Michigan. The amendments updated the IRP statute by revising planning parameters, filing requirements, and the considerations the Commission must evaluate when reviewing an IRP. The Commission has also undertaken implementation activities through its IRP-related workstream for the Michigan 2023 energy law in Case No.

Line
No.

U-21570 and U-21867. MCL 460.6t, as amended by 2023 PA 231, also requires the Commission to establish modeling scenarios and assumptions for utility IRPs including assumptions related to planning reserve margins, local clearing requirements, applicable environmental regulations, supply-side and demand-side resources, projected EWR savings, projected load impacts due to electrification, projected load management and demand response savings, regional infrastructure limitations, and projected costs of generation technologies and fuels.

2023 PA 231 also broadens the evaluation of the IRP beyond a comparison of generation alternatives alone. In its December 18, 2025, order in Case Nos. U-21867 and U-21570, the Commission adopted revised IRP filing requirements that include an EJ analysis, long-term forecasts of greenhouse gas emissions and other pollutants, projected rate and affordability impacts, and the alignment of renewable energy plans, energy optimization plans, and IRPs. For purposes of this IRP, these changes reinforce the need for the Company to present a plan that addresses reliability, affordability, compliance with state law, environmental considerations, and the practical implementation of its resource portfolio.

Q62. How did 2023 PA 235 affect the Company's clean energy, renewable energy, energy storage, and DG planning obligations?

A62. 2023 PA 235 made several changes that are directly relevant to the Company's resource planning. Four key changes are discussed here.

First, 2023 PA 235 established a clean energy standard under MCL 460.1051, under which electric providers must achieve a clean energy portfolio of at least 80% in

Line
No.

2035–2039 and 100% in 2040 and beyond. I discussed the Company's compliance with the CES in Part II of my testimony.

Second, 2023 PA 235 increased Michigan's renewable energy standard under MCL 460.1028. Under the new standard, electric utilities must achieve a renewable energy credit portfolio of at least 15% through 2029, 50% in 2030–2034, and 60% in 2035 and beyond. Witness Bilyeu further discusses the statutory renewable energy requirements, the renewable energy resources included in the IRP, and the Company's plan for renewable energy.

Third, 2023 PA 235 established a statewide energy storage target under MCL 460.1101. By December 31, 2029, rate-regulated electric utilities must petition the Commission for necessary approvals, and alternative electric suppliers must submit plans to the Commission, to construct or acquire eligible energy storage systems or enter into eligible energy storage contracts to meet their share of a statewide energy storage target of at least 2,500 MW. Witness Schroeder further discusses the statutory energy storage requirements, the energy storage resources included in the IRP, and the Company's plan for energy storage.

Fourth, 2023 PA 235 increased the DG program cap under MCL 460.1173 from 1% to 10% of an electric utility's average five-year in-state peak load. At least 50% of the cap must be reserved for systems under 20 kW, and not more than 50% of the cap may be allocated for systems larger than 20 kW but not more than 550 kW. Witness Sirwaitis further discusses how DG is incorporated into the Company's load forecast and IRP planning. Taken together, these provisions affect the

Line No.

Company's IRP by establishing future statutory requirements and expanding the set of resources and customer programs that must be considered in long-term planning.

Q63. How did 2023 PA 229 affect EWR planning?

A63. 2023 PA 229 established new EWR targets for electric and natural gas utilities and required the filing of new customer energy optimization plans in 2025 under MCL 460.1071. Beginning in 2026, MCL 460.1077 requires EWR programs to collectively achieve incremental energy savings equivalent to 1.5% of total retail electricity sales in megawatt-hours in the preceding year. 2023 PA 229 also establishes a goal that, collectively, an electric provider's programs should achieve incremental energy savings equivalent to 2% of total retail electricity sales in the preceding year. These changes are relevant because EWR programs are demand-side resources that can reduce customer usage, offset future resource needs, and affect both the capacity and energy requirements evaluated in the IRP. Witness Kupser further discusses the statutory EWR requirements, the EWR assumptions, inputs, and resource levels included in the IRP, and the Company's plan for EWR.

Q64. How did the 2023 PA 233 affect siting for renewable energy and energy storage projects?

A64. 2023 PA 233 established a process under which the Commission may approve the siting of certain utility-scale renewable energy and energy storage facilities under specified circumstances. The Act also established the framework for applications seeking Commission approval of eligible facilities. In October 2024, in Case No. U-21547, the Commission adopted the Application Filing Instructions and

Line
No.

Procedures[7] related to applications that are to be filed under 2023 PA 233. The process applies to solar facilities with a nameplate capacity of 50 MW or more, wind facilities with a nameplate capacity of 100 MW or more, and energy storage facilities with a nameplate capacity of 50 MW or more and a discharge capability of 200 MWh or more. This siting legislation is relevant to the IRP because the ability to implement renewable and energy storage plans requires permitting, siting, interconnection, and construction timelines, all of which can affect the feasibility and timing of resource additions evaluated in the IRP.

Q65. How has the Company incorporated the requirements of the 2023 Michigan energy laws into this IRP?

A65. First, the 2023 Michigan energy laws changed the legal requirements that the Company must account for in long-term resource planning, including the new clean energy, increased renewable energy and EWR requirements, the statewide energy storage target, and the increase to the DG program cap. Second, these laws changed the IRP process itself by expanding the planning considerations evaluated under MCL 460.6t, including emissions, EJ, affordability, and alignment across related utility plans. Third, these changes affect the mix of supply-side, demand-side, and customer-sited resources that must be considered in developing the most reasonable and prudent plan for customers.

In this IRP, the Company has considered these statutory changes as part of its overall planning framework. As a result, the Company identified the most

[7] MPSC, Order in Case No. U-21547, October 10, 2024, as corrected by October 21, 2024 Errata, Ex. A, Corrected Application Filing Instructions and Procedures.

Line No.

reasonable and prudent plan that meets customer needs in a reliable and affordable manner while complying with applicable Michigan law.

Federal Policy Updates

Q66. Why is federal energy policy relevant to the Company's IRP?

A66. Michigan's IRP statute, MCL 460.6t, requires consideration of applicable federal environmental regulations and laws as part of the resource planning process. More broadly, federal policy can affect the economics, timing, funding, development, and regulatory obligations associated with both existing and potential resources. Since the Company's 2022 IRP, federal policy has continued to influence resource planning through tax incentives, federal financing programs, environmental regulations, and broader development considerations. First, I will discuss tax incentives. The IRA of 2022 established and expanded several clean energy tax incentives, including the clean electricity production tax credit under Section 45Y and the clean electricity investment tax credit under Section 48E. Those tax credits affected the relative economics of renewable resources, energy storage, and other qualifying clean energy technologies and therefore are relevant to the evaluation of resources in this IRP. Subsequent federal legislation, including Public Law 119-21, commonly referred to as the One Big Beautiful Bill Act of 2025 (OBBBA), modified the availability and timing of certain federal clean energy tax credits, particularly for wind and solar resources.[8] Federal policy also affects the availability of financing mechanisms for qualifying energy infrastructure projects, including loan programs administered by the U.S. Department of Energy (DOE).

[8] One Big Beautiful Bill Act, Pub. L. No. 119-21, Sections 70512–70513. July 4, 2025.

Line
No.

In addition, applicable and formally proposed federal environmental regulations affect long-term planning for existing and new thermal resources.

Q67. How did the IRA affect resource economics and financing?

A67. The IRA affected resource economics by establishing technology-neutral clean electricity tax credits that can reduce the cost of qualifying clean energy resources. Sections 45Y and 48E were added to the Internal Revenue Code by the IRA. Section 45Y provides a clean electricity production tax credit, and Section 48E provides a clean electricity investment tax credit for qualified facilities that do not emit greenhouse gases, and for energy storage technology placed in service after 2024.[9] These credits are important in resource planning because they can materially affect the relative cost of resource alternatives evaluated in an IRP. In general, production tax credits affect the economics of energy production from qualifying facilities, while investment tax credits affect the upfront capital cost of qualifying facilities and energy storage technology. The availability of these tax credits can impact the cost assumptions of available resources and therefore influence portfolio modeling. Tax credits established by the IRA, including Sections 45Y and 48E, materially affected the economics of certain resources evaluated in long-term resource planning.

The IRA also established and expanded federal financing opportunities through the U.S. DOE[10], including the Section 1706 program, subsequently amended and

[9] 26 U.S.C. Sections 45Y and 48E; Inflation Reduction Act of 2022, Pub. L. No. 117-169, Sections 13701–13702.

[10] The Inflation Reduction Act created the Energy Infrastructure Reinvestment Program under Section 1706. Following enactment of Pub. L. No. 119-21, DOE reestablished the program as the Energy

Line No.

renamed the Energy Dominance Financing Program, which provides access to federal loan financing for eligible energy infrastructure projects and may therefore influence the financing costs associated with implementing the plan.

Q68. Have there been any changes to the Section 45Y and 48E federal tax credits since the IRA was established?

A68. Yes. The OBBBA modified the availability and timing of certain IRA clean energy tax credits. In particular, OBBBA accelerated the termination of the Section 45Y production tax credit and Section 48E investment tax credit for certain wind and solar facilities. For applicable wind and solar facilities, the OBBBA generally terminates these credits for facilities placed in service after December 31, 2027, if construction begins after July 4, 2026. These changes are relevant to the IRP because the value and availability of federal tax credits can affect resource economics and project timing. As a result, the Company must continue to monitor federal tax law and guidance when evaluating future resource additions.

Q69. How do federal emissions regulations inform the Company's IRP?

A69. Federal emissions regulations are relevant because they can affect the cost, operating flexibility, compliance obligations, and long-term viability of existing and future resources. Since the Company's last IRP, the federal emissions regulatory landscape for power plants has continued to evolve.

Dominance Financing Program. See Inflation Reduction Act of 2022, Section 50144; Pub. L. No. 119-21, Section 50403; U.S. Department of Energy, Energy Dominance Financing Program, https://www.energy.gov/edf/energy-dominance-financing-program; U.S. Department of Energy, *Office of Energy Dominance Financing*, https://www.energy.gov/EDF. Accessed August 24, 2026.

Line
No.

In 2024, the United States Environmental Protection Agency (EPA) finalized greenhouse gas standards and emission guidelines for fossil fuel-fired electric generating units under Section 111 of the Clean Air Act (42 U.S.C. § 7411) (Section 111 2024 Rule).

In June 2025, EPA proposed repealing the Section 111 2024 Rule or, alternatively, certain requirements established by that rule. On September 14, 2026, EPA finalized a partial repeal of the Section 111 2024 Rule, including the emission guidelines applicable to existing fossil fuel-fired steam generating units and certain CCS-based standards for modified coal-fired units and new baseload combustion turbines. The final rule did not repeal the remaining efficiency-based standards applicable to new combustion turbines. At the same time, EPA issued a supplemental proposal to support rescission of the underlying greenhouse gas findings and repeal the remaining greenhouse gas emission standards for fossil fuel-fired power plants under Section 111.

These actions materially change the federal regulatory framework applicable to fossil fuel-fired generation. Because the final partial repeal and the supplemental proposal have different procedural postures, the Company does not assume that all federal greenhouse gas requirements applicable to fossil-fueled generation have been finalized. The Company will continue to monitor the effective date and implementation of the final rule, the supplemental rulemaking, and related litigation, and evaluate any resulting impacts on Company resources and long-term resource planning.

Witness Marietta further describes the environmental regulations applicable to the Company's generation fleet in his testimony.

Q70. What other federal environmental regulatory developments have the Company considered since its 2022 IRP?

A70. The EPA also finalized a 2024 rule strengthening certain wastewater discharge limitations for steam electric power generating units under the Clean Water Act. Since then, EPA has extended certain compliance deadlines established under the rule and proposed revisions to requirements applicable to unmanaged combustion residual leachate. These regulatory developments may affect compliance obligations, costs, and future investments at certain Company facilities. Witness Marietta discusses the applicable wastewater regulations, subsequent regulatory developments, and the Company's compliance strategy in greater detail.

Q71. How has the Company accounted for changes to federal tax credits, emissions regulations, and other environmental regulations in this IRP?

A71. The Company considered changes to federal tax credits, emissions regulations and other environmental regulations as part of the broader planning environment for this IRP. Changes in federal policy related to federal tax credits and emissions and other environmental regulations can affect resource economics, compliance costs, operating requirements, timing, project development risks, and long-term viability of existing and future resource options. In addition, the Company considered evolving federal policies affecting clean energy supply chains, including prohibited foreign entity and related foreign-sourcing requirements that may affect the timing, availability, and cost of certain renewable energy and energy storage technologies.

Line
No.

Witnesses Bilyeu and Schroeder discuss the considerations for renewable energy and energy storage technologies in more detail in their respective testimonies.

The Company's approach is to evaluate resource options based on the information available at the time of the IRP and consistent with the planning parameters and assumptions established for this proceeding. As part of those planning parameters, the Company evaluates applicable state and federal tax credits, environmental regulations, laws, and rules, as well as formally proposed regulations that may affect electric utilities and power generation resources.[11] See Witness Busse for further explanation of how the Company accounted for changes to federal tax credits.

Because federal policy continues to evolve, regulatory uncertainty is also relevant to long-term resource planning. Witness Marietta further discusses the environmental regulations applicable to the Company's generation fleet and the impacts of potential compliance options.

MISO Policy Updates

Q72. MISO has made several changes to its resource adequacy framework. Can you describe the seasonal resource adequacy construct?

A72. MISO implemented a seasonal resource adequacy construct beginning with Planning Year 2023/2024. Under the seasonal construct, MISO evaluates resource adequacy across four seasons rather than focusing primarily on summer peak

[11] MPSC, Order in Case Nos. U-21570 and U-21867, December 18, 2025, Ex. A, Michigan Integrated Resource Planning Parameters, Section VI, "State and Federal Environmental Regulations, Laws and Rules"; MCL 460.6t(1)(c)–(d).

Line
No.

conditions.[12] This approach is intended to recognize that reliability risks, customer demand, and resource availability can vary throughout the year and requires load-serving entities to maintain sufficient accredited capacity to satisfy MISO's resource adequacy requirements in each season.[13]

The seasonal construct is relevant to long-term resource planning because the Company must plan for sufficient accredited capacity to meet MISO's resource adequacy requirements throughout the year.

Q73. What is MISO's Direct Loss of Load (DLOL) resource accreditation methodology?

A73. MISO is transitioning to a Direct Loss of Load (DLOL)-based accreditation methodology. Resource accreditation is the process of assigning capacity value to a resource based on its contribution to system reliability during periods of highest system risk.[14] MISO's Resource Accreditation White Paper describes the DLOL framework as an approach that combines forward-looking probabilistic analysis of resource-class performance with resource-specific historical performance during periods of high system risk.[15] The objective of implementing DLOL is to improve reliability planning. These changes are relevant to the IRP because changes in

[12] MISO, Planning Resource Auction Results for Planning Year 2023–24. May 19, 2023. https://cdn.misoenergy.org/2023%20Planning%20Resource%20Auction%20%28PRA%29%20Results628925.pdf. Accessed August 24, 2026.
[13] MISO, Resource Accreditation White Paper, Version 2.1. March 28, 2024. https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf Accessed August 24, 2026.
[14] Federal Energy Regulatory Commission, Midcontinent Independent System Operator, Inc., 189 FERC 61,065, PP 1, 8–9 (Oct. 25, 2024), Docket Nos. ER24-1638-000 and ER24-1638-001, Order Accepting Proposed Tariff Revisions, Accession No. 20241025-3063. Accessed September 23, 2026.
[15] Federal Energy Regulatory Commission, Midcontinent Independent System Operator, Inc., 189 FERC 61,065, PP 1, 8–9 (Oct. 25, 2024), Docket Nos. ER24-1638-000 and ER24-1638-001, Order Accepting Proposed Tariff Revisions, Accession No. 20241025-3063. Accessed September 23, 2026.

Line No.

resource accreditation can affect the amount and mix of resources needed to satisfy future resource adequacy requirements.

Q74. Why is MISO's resource adequacy construct, including its seasonal construct and resource accreditation method changes, relevant to the Company's IRP?

A74. Changes to MISO's resource adequacy construct, including its seasonal construct and resource accreditation methods, are relevant because they affect both the amount of capacity needed in each season and the accredited capacity value of resources for planning purposes. MISO has stated that, as the resource portfolio evolves and reliability risk shifts, resource adequacy practices and accreditation methods must also evolve to better reflect how resources contribute during periods of system risk.[16]

At the same time, MISO and the Organization of MISO States (OMS) have identified growing resource adequacy uncertainty associated with load growth, large load additions, the pace of new resource additions, retirement timing, seasonal reliability risk, and project deployment timelines.[17] Taken together, these developments indicate that the IRP should include resource adequacy analyses that reflect MISO's seasonal planning requirements and applicable accredited values and evaluate resource portfolios across seasonal reliability conditions.[18]

[16] MISO, Resource Accreditation White Paper, Version 2.1. March 28, 2024. https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf Accessed August 24, 2026.
[17] MISO and Organization of MISO States, 2025 OMS-MISO Survey Results. June 2025. https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf. Accessed August 24, 2026.
[18] MISO, Resource Accreditation White Paper, Version 2.1. March 28, 2024. Federal Energy Regulatory Commission, Midcontinent Independent System Operator, Inc., 189 FERC 61,065, PP 1, 8–9 (Oct. 25,

Line
No.

Q75. How do MISO's resource accreditation reforms affect the way the Company evaluates resource capacity in long-term planning?

A75. MISO's resource accreditation reforms change how accredited values are determined by more directly considering a resource's expected contribution to reliability during periods of highest system risk.[19]

Under MISO's DLOL construct, accreditation can vary significantly by resource type and season. MISO's DLOL methodology does not indicate that any particular resource type lacks value. Rather, they illustrate the importance of considering both the amount of installed capacity and the accredited capacity contribution of resources when evaluating future portfolios. From a resource planning perspective, the Company incorporates these methodologies in its long-term system planning.

Q76. How will the Company reflect MISO's seasonal resource adequacy construct and DLOL methodology changes in this IRP?

A76. MISO's recent resource adequacy and accreditation changes support an IRP planning approach that uses nameplate capacity as one input, while placing greater emphasis on accredited capacity values and expected resource contribution during periods when the electric system is at highest risk. The Company will do the following to address these changes:

2024), Docket Nos. ER24-1638-000 and ER24-1638-001, Order Accepting Proposed Tariff Revisions, Accession No. 20241025-3063. Accessed September 23, 2026; MISO, Wind and Solar Capacity Credit Report: Planning Year 2025/2026. March 2025. https://cdn.misoenergy.org/PY%2025-26%20Wind%20and%20Solar%20Capacity%20Credit%20Report684294.pdf. Accessed August 24, 2026.

[19] Federal Energy Regulatory Commission, Midcontinent Independent System Operator, Inc., 189 FERC 61,065, PP 1, 8–9 (Oct. 25, 2024), Docket Nos. ER24-1638-000 and ER24-1638-001, Order Accepting Proposed Tariff Revisions, Accession No. 20241025-3063. Accessed September 23, 2026.

Line
No.

- Incorporate MISO's resource adequacy construct and DLOL methodology into the IRP process,
- Evaluate resource portfolios using MISO's seasonal resource adequacy requirements rather than relying on annual or summer-peaking capacity metrics only, and
- Conduct extensive resource adequacy studies across key years and scenarios to evaluate portfolio performance during high-risk periods and assess whether the PCA remains resource adequate under varying system conditions.

Load Forecast Changes

Q77. Why are load growth changes an important planning consideration in this IRP?

A77. After many years of relatively modest load growth across the MISO footprint, electric utilities are now planning in an environment where demand growth is becoming a more significant driver of resource planning. MISO has stated that its peak load remained essentially flat over the prior fifteen-year period, but that its updated forecast projects peak demand growth of approximately 1% to 2% per year through 2044 on a compound annual growth rate basis, with growth concentrated in the northern and central portions of the footprint.[20]

MISO has stated that data centers, new industrial development, and green hydrogen are primary drivers of its updated long-term load outlook, representing a shift from

[20] MISO, Long-Term Load Forecast White Paper. December 2024; MISO, 2024 Load Forecast and Process Enhancements Workshop Presentation. December 18, 2024.

Line No.

previous outlooks that focused more heavily on electric vehicles and building electrification.[21]

This matters for the IRP because higher load growth can affect both the amount and timing of resources needed to maintain reliability. MISO's updated long-term load forecast estimates that peak demand could increase by approximately 1% to 2% per year through 2044, which is materially higher than the 0.4% to 1.1% compound annual growth rate reflected in prior MISO Futures scenarios.[22] Accordingly, load growth is a core planning variable that can affect energy and capacity needs, infrastructure needs, and portfolio timing.

Q78. How does the Company use the term "large load" in this case proceeding?

A78. The term "large load" is used in several distinct regulatory, forecasting, and modeling contexts relevant to this IRP, and no single megawatt threshold applies across all those contexts. For example, the IRP Filing Requirements approved in the Commission's December 18, 2025 Order in Case Nos. U-21867 and U-21570 require the Company to include all contracted large loads in its base load forecast, describe the load and peak-demand characteristics of large loads included in its base or alternative load forecasts, and develop low, medium, and high large load forecasts based on probabilistic weighting of known interested large loads. Those forecasting requirements are not limited to customers or projects exceeding a single specified megawatt threshold. For a separate PCA reporting requirement, however,

[21] MISO, Long-Term Load Forecast White Paper. December 2024; MISO, 2024 Load Forecast and Process Enhancements Workshop Presentation. December 18, 2024.
[22] MISO, Long-Term Load Forecast White Paper. December 2024; MISO, 2024 Load Forecast and Process Enhancements Workshop Presentation. December 18, 2024.

Line
No.

the IRP Filing Requirements require specified information when the PCA includes a new large load that is greater than 300 MW with a load factor greater than 80%.

Accordingly, the Company uses the term "large load" according to the particular statutory, Commission, forecasting, or modeling requirement being addressed, rather than applying a single numerical threshold throughout the filing. When discussing the individual contracted customers included in the base forecast, the Company identifies them by name as OACS in MPSC Case No. U-21990 and Google in MPSC Case No. U-22058.

The term "data center" describes a type of facility or load and is not used in this filing as a separate regulatory category, as a synonym for "large load," customer class, or as the basis for a generally applicable megawatt threshold. A data center may constitute a large load for a particular analysis, but the broader term "large load" may also include other types of commercial or industrial customers. The Company therefore uses "data center" only when the facility type is relevant to a particular discussion, such as explaining operating characteristics unique to those facilities or identifying that facility type when the distinction is material.

When discussing prospective customer growth, broader load forecasts, or required large load sensitivities, the Company uses the broader term "large load" because those analyses are not limited to data centers.

Q79. Why may large load additions require different treatment than traditional load growth in the Company's forecast?

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A79. Traditional load growth generally develops through changes in economic activity, demographics, customer counts, and customer usage patterns. In contrast, an individual large load project may represent a substantial and concentrated addition to electric demand with a project-specific development schedule, anticipated energization date, and load ramp. A single large load project can represent a significant addition to system demand, and multiple projects developing over similar periods can materially change local or system planning needs. Prospective large load growth also involves uncertainty regarding which projects will take service and the timing and magnitude of their associated demand. MISO has noted that new load drivers are materially increasing the outlook for load growth and that there is substantial uncertainty regarding the magnitude and timing of that growth, as well as the resources needed to meet it.[23]

Certain large load additions, including data centers, may also have load characteristics that materially affect both annual energy requirements and peak-demand forecasts. Data centers, as energy-intensive facilities, can have substantial electricity requirements driven by information technology equipment and supporting infrastructure, including cooling systems.[24] These characteristics support evaluating identified large load additions separately from the economic and demographic trends used to forecast more traditional load growth.

[23] MISO, 2024 Load Forecast and Process Enhancements Workshop Presentation. December 18, 2024. https://cdn.misoenergy.org/20241218%20Medium%20and%20Long%20Term%20Forecast%20Workshop%20Presentation667265.pdf. Accessed August 24, 2026.

[24] Sarah J. Smith, Alex Hubbard, Alex Newkirk, Mohan Ganeshalingam, Billie Holecek, Dale Sartor, Michael Mills, and Arman Shehabi, United States Data Center Energy Usage Report: 2025 Update, Lawrence Berkeley National Laboratory. Executive Summary, p. 5. June 18, 2026. https://doi.org/10.71468/P1RP4F. Accessed August 24, 2026

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Q80. What planning considerations arise from potential large load growth?

A80. The principal planning consideration is whether prospective large load additions can be reliably accommodated as they materialize, given their timing, size, location, and operating characteristics and the availability and timing of generation resources and grid infrastructure that may be needed to serve them. Forecasts of prospective large load growth may indicate substantial potential demand growth, but there is uncertainty regarding which projects will take service and the timing, magnitude, location, and operating characteristics of the associated demand. In the specific context of data center growth, S&P Global notes that uncertainty remains regarding the pace of data center power demand, the grid resources needed to serve that demand, and the role of large-scale onsite power alternatives.[25]

This consideration is important because the resources and infrastructure needed to serve material load growth often require long development timelines. New generation, energy storage, transmission, and distribution infrastructure may require permitting, interconnection studies, equipment procurement, construction, and regulatory approvals. The 2025 OMS-MISO Survey identifies large spot-load additions, resource deployment timelines, and load growth as key uncertainties for resource adequacy planning.[26] Accordingly, the Company evaluated a range of potential load-growth sensitivities to assess how future resource needs may vary, including the potential effects of incremental large, high load-factor loads.

[25] Garrett Hering and Susan Dlin, "Data Center Grid-Power Demand to Rise 22% in 2025, Nearly Triple by 2030," S&P Global Commodity Insights. October 14, 2025. https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/101425-data-center-grid-power-demand-to-rise-22-in-2025-nearly-triple-by-2030. Accessed August 24, 2026.
[26] MISO and Organization of MISO States, 2025 OMS-MISO Survey Results. June 2025. https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf. Accessed August 24, 2026.

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Q81. How did the Company address load growth in its planning assumptions in the IRP?

A81. The Company evaluated a range of load-growth outcomes to account for uncertainty regarding the magnitude, timing, and sources of future electricity demand. These analyses included higher and lower overall load-growth assumptions, low, medium, and high large load growth sensitivities, and alternative assumptions regarding electric vehicle adoption, building electrification, and distributed generation.

As discussed above, external forecasts identify data centers as one source of potential future load-growth while emphasizing uncertainty regarding the magnitude and timing of future demand. The Company addressed that uncertainty by evaluating prospective large load growth through sensitivities, without assuming that each project is contracted or will ultimately take service.

Those sensitivities allow the Company to evaluate how different levels and sources of future load growth could affect resource needs and portfolio outcomes. Witness Sirwaitis describes the development of the load forecasts and associated assumptions, and Witness Manning describes how these forecasts were evaluated in the IRP modeling.

Q82. How did the Company account for projected electric vehicle growth in the IRP?

A82. The Company evaluated alternative electric vehicle adoption assumptions to assess how different levels of transportation electrification could affect future load growth

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and resource needs. Witness Sirwaitis describes the electric vehicle assumptions reflected in the load forecasts, and Witness Manning explains how the resulting forecasts were evaluated in the IRP modeling.

Q83. How did the Company account for uncertainty in DG in the planning assumptions?

A83. The Company evaluated alternative DG assumptions to assess how different levels of customer adoption could affect future net load and resource needs. Witness Sirwaitis describes the DG forecasts and sensitivities, and Witness Manning explains how those assumptions were evaluated in the IRP modeling.

Resource Development

Q84. What resource development challenges may affect future resource additions?

A84. New generation, energy storage, and grid infrastructure can require engineering studies, interconnection studies, permitting and siting approvals, major equipment procurement, construction, and workforce availability. Each of these steps can affect the timing, cost, and certainty of resource additions. Given legacy power plant retirements, load growth, evolving resource adequacy requirements, and clean energy policies, resource development efforts may face supply chain constraints, equipment shortages, labor availability limitations, permitting requirements, and siting challenges that can result in higher costs and project delays.

Q85. National and regional evidence indicates that many projects are taking longer to move from request to commercial operation, and that supply chain constraints are affecting major electrical equipment needed for generation

Line No.

and grid infrastructure.[27] Why are these resource development challenges relevant to the Company's IRP?

A85. These challenges are relevant because resource plans must consider not only the value of potential resources, but also the practical ability to develop, interconnect, procure, construct, and place resources in service when needed.

Q86. How do interconnection queue conditions affect resource development timelines?

A86. Interconnection queue conditions can affect resource development timelines because most new utility-scale generation and energy storage resources seeking new transmission interconnection service must complete transmission interconnection studies before they can be placed in service. Lawrence Berkeley National Laboratory reports that, as of the end of 2025, there were approximately 8,200 projects actively seeking grid interconnection in the United States, representing approximately 1,312 GW of generation and 749 GW of storage.[28] The same report states that only 13% of capacity that submitted interconnection requests from 2000 through 2020 reached commercial operation by the end of 2025, while 75% had been withdrawn and 10% remained active.

[27] Joseph Rand et al., Queued Up: 2026 Edition—Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2025, Lawrence Berkeley National Laboratory. 2026. https://emp.lbl.gov/queues. Accessed September 16, 2026; U.S. Department of Energy, Office of Electricity, "DOE and Industry Team Up to Keep the Lights On for America." February 22, 2024. https://www.energy.gov/oe/articles/doe-and-industry-team-keep-lights-america. Accessed September 15, 2026; Killian McKenna, Sherin Ann Abraham, and Wenbo Wang, Major Drivers of Long-Term Distribution Transformer Demand, National Renewable Energy Laboratory. February 2024. https://www.osti.gov/biblio/2309697. Accessed August 24, 2026.

[28] Joseph Rand et al., Queued Up: 2026 Edition -Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2025, Lawrence Berkeley National Laboratory. 2026. https://emp.lbl.gov/queues. Accessed September 16, 2026

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The time required for successful projects to move through the interconnection process has also increased. Lawrence Berkeley National Laboratory reports that for regions with available data, the median duration from interconnection request to commercial operation was more than five years for projects that reached commercial operation in 2025.[29] These national trends are relevant because they show that interconnection timing can be a material resource development risk for new resources.

MISO has recognized similar issues in its own generator interconnection process. MISO's generator interconnection queue improvement materials state that queue reforms are needed to reduce the volume of future queue cycles and enable faster and more certain study results earlier in the process.[30] MISO has implemented several reforms, including its queue cap framework and the Expedited Resource Addition Study (ERAS) process, to help address queue volume and accelerate certain resources needed for near-term reliability.[31] These reforms may improve the process over time, but interconnection remains an important planning consideration because projects may still face study timelines, withdrawal-driven restudies, network upgrade requirements, and uncertainty regarding final interconnection costs. In addition, project withdrawals can trigger cascading restudies that affect other projects in the queue, creating additional uncertainty regarding development

[29] Joseph Rand et al., Queued Up: 2026 Edition -Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2025, Lawrence Berkeley National Laboratory. 2026. https://emp.lbl.gov/queues. Accessed September 16, 2026

[30] MISO, Generator Interconnection Queue Improvements, Planning Advisory Committee. https://cdn.misoenergy.org/20230719%20PAC%20Item%2006%20GI%20Queue%20Improvements%20Proposal629634.pdf. July 19, 2023, p. 2.
Accessed August 24, 2026.

[31] MISO, Generator Interconnection, Expedited Resource Addition Study (ERAS). https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/ferc-approves-misos-expedited-resource-addition-study/Accessed August 24, 2026.

Line No.

schedules and expected in-service dates even as MISO implements new queue reforms.

Q87. How do supply chain constraints affect resource development?

A87. Supply chain constraints can affect resource development by increasing the cost and lead time for major electrical equipment. The U.S. DOE has identified transformers as critical components of the electric grid and has noted that aging infrastructure, renewable generation deployment, electrification, and other new grid demands are increasing pressure on transformer supply chains.[32] The National Renewable Energy Laboratory similarly reports that distribution transformers are experiencing major shortages, with utilities facing extended lead times of up to two years and prices increasing by as much as five to six times in recent years.[33]

These constraints are not limited to distribution equipment. The International Energy Agency reports that procurement times and prices for essential transmission grid components have nearly doubled since 2021, with procurement taking two to three years for cables and up to four years for large power transformers. The same report states that large transformer prices have increased by approximately 75% in real terms since 2019[34]. For IRP purposes, these supply chain conditions are

[32] U.S. Department of Energy, Office of Electricity, DOE and Industry Team Up to Keep the Lights On for America, February 22, 2024. https://www.energy.gov/oe/articles/doe-and-industry-team-keep-lights-america. Accessed September 15, 2026.
[33] Killian McKenna, Sherin Ann Abraham, and Wenbo Wang, Major Drivers of Long-Term Distribution Transformer Demand, National Renewable Energy Laboratory. February 2024. https://www.osti.gov/biblio/2309697. Accessed August 24, 2026.
[34] International Energy Agency, Rising component prices and supply chain pressures are hindering the development of transmission grid infrastructure, February 25, 2025. https://www.iea.org/news/rising-component-prices-and-supply-chain-pressures-are-hindering-the-development-of-transmission-grid-infrastructure. Accessed August 24, 2026.

Line No.

relevant because equipment availability can become a critical-path item for new generation, energy storage, substations, and transmission-related infrastructure.

Supply chain constraints can also affect the procurement of major generation equipment. Industry assessments indicate that procurement lead times for combustion turbines and combined-cycle gas turbine equipment have increased significantly in recent years due to growing demand for dispatchable generation resources. These extended procurement timelines are relevant to long-term resource planning because they reinforce the importance of evaluating realistic development schedules and initiating development activities sufficiently in advance of anticipated resource needs and planned retirements.

In addition, supply chain constraints can also affect dispatchable resource development. McKinsey has identified energy supply chain issues, project permit bottlenecks, and labor availability as critical challenges for meeting rising U.S. electricity demand, and notes that supply chain challenges can contribute to multiyear lead times for equipment needed to add new dispatchable capacity.[35] As a result, portfolio planning should consider whether assumed resource additions depend on long-lead equipment that may require earlier procurement decisions, schedule contingencies, or alternative planning options.

Q88. How do permitting, siting, and labor constraints affect resource development?

[35] McKinsey & Company, Powering a new era of US energy demand, April 29, 2025. https://www.mckinsey.com/industries/public-sector/our-insights/powering-a-new-era-of-us-energy-demand. Accessed August 24, 2026.

Line No.

A88. Permitting and siting requirements can affect the timing and certainty of resource development because generation, storage, and transmission-related infrastructure often require multiple approvals before construction can begin. As noted above, 2023 PA 233 established a process under which the Commission may approve the siting of certain utility-scale renewable energy and energy storage projects. This process may provide a pathway for siting certain projects, although siting and permitting remain important resource development considerations because they can influence development timelines, community engagement requirements, and the ability to secure required approvals.

Labor availability is also a resource development consideration. The International Energy Agency reports that approximately 8 million people are currently employed globally in constructing, maintaining, and operating power grids, and that this workforce is expected to grow by at least 1.5 million by 2030 to meet projected demand.[36] McKinsey similarly identifies labor availability as one of the major challenges the U.S. energy sector must address to deliver the resources and infrastructure needed to serve rising electricity demand.[37] These workforce considerations are relevant to the IRP because higher levels of simultaneous generation, energy storage, grid, and large load infrastructure development can increase competition for skilled labor, engineering resources, construction crews, and specialized contractors.

[36] International Energy Agency, Rising component prices and supply chain pressures are hindering the development of transmission grid infrastructure, February 25, 2025. https://www.iea.org/news/rising-component-prices-and-supply-chain-pressures-are-hindering-the-development-of-transmission-grid-infrastructure. Accessed August 24, 2026.

[37] McKinsey & Company, Powering a new era of US energy demand, April 29, 2025. https://www.mckinsey.com/industries/public-sector/our-insights/powering-a-new-era-of-us-energy-demand. Accessed August 24, 2026.

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Q89. How did the Company consider resource development challenges in this IRP?

A89. The Company considered resource development challenges by incorporating resource availability assumptions that reflect expected development timelines, estimated interconnection timing, equipment procurement considerations, permitting and siting requirements, labor availability, and customer cost impacts. The basis for these assumptions is discussed in greater detail by Witnesses Busse, Pratt, Banks, Bilyeu, and Schroeder. The assumptions are intended to reflect practical constraints associated with developing new resources and are consistent with the broader planning environment discussed earlier in my testimony.

The Company also considered sensitivities that evaluated changes in resource timing and availability, higher resource costs, and alternative resource mixes, as discussed by Witness Manning.

PART IV: IRP PLANNING OBJECTIVES, PROCESS, AND STAKEHOLDER ENGAGEMENT

IRP Planning Objectives

Q90. What planning objectives guided the Company's IRP development?

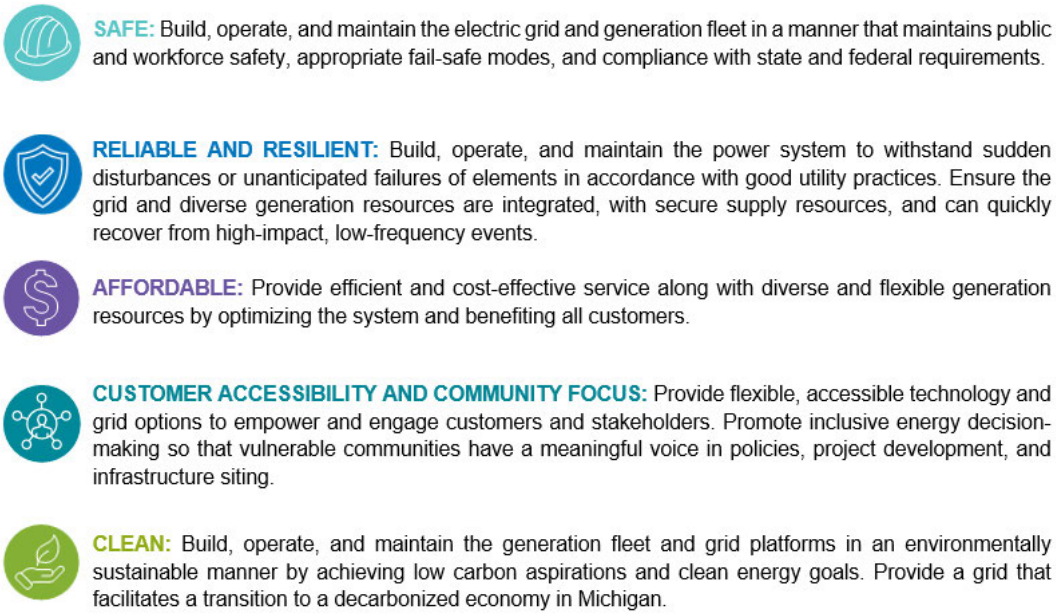
A90. The Company's planning objectives are grounded in factors historically used to guide resource planning and distribution planning. The Company's planning objectives were first formally documented during the development of the 2017 CON. These objectives were then refined in 2021 and further updated in 2026.

The current planning objectives were developed cross-functionally with the Company's Distribution Operations team and were used in the development of the

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long-term resource plan. The planning objectives are: Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean, and are defined in Figure 3.

Figure 3 – DTE Planning Objectives



Q91. How does the Company apply the planning objectives to the IRP process?

A91. The planning objectives were applied throughout the IRP process to develop a plan that satisfies statutory requirements, considers stakeholder input and meets the planning objectives. The Company considered the planning objectives in its evaluation. For example, to align the PCA with the "clean" planning objective, the Company considered clean energy systems definitions and other clean requirements. As discussed by Witness Manning, the Company developed a robust plan that performed well using the planning objectives. While some portfolios may

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perform better on an individual planning objective, the Company sought to optimize a balanced portfolio that met the planning objectives overall.

Balancing the planning objectives is important because resource planning must address multiple considerations. The Company uses these objectives to ensure the system remains dependable at all hours of the day, remains affordable for its customers, complies with all statutory and regulatory requirements, and remains safe for its customers and workers.

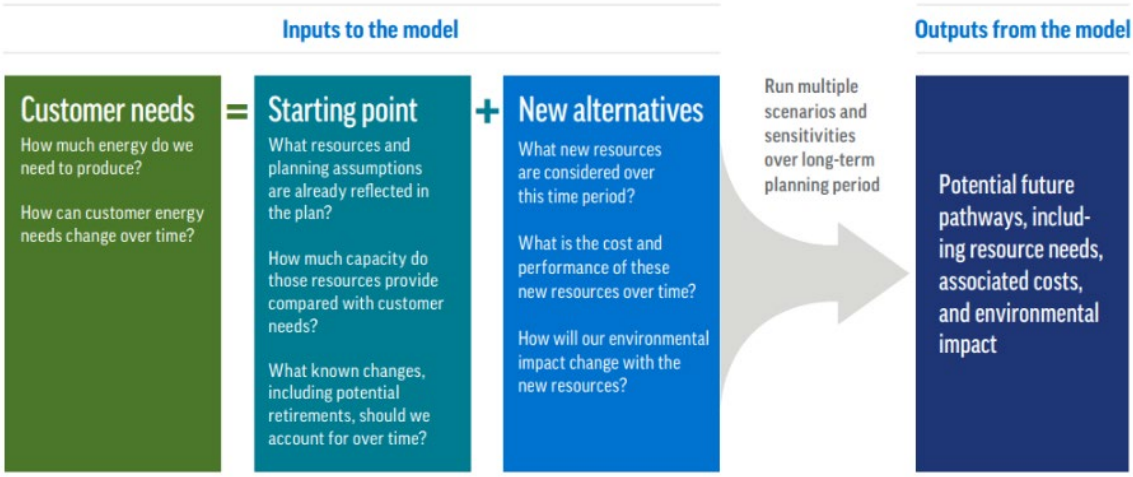
IRP Process

Q92. Can you please describe the Company's approach to creating the IRP?

A92. Yes. The Company's approach to creating the 2026 IRP is consistent with the approach taken in the 2022 IRP. At the highest level, as shown in Figure 4, the IRP model considers various combinations of the Company's starting point planning resources and assumptions together with available incremental resource alternatives to determine potential resource portfolios that meet customer energy and capacity needs.

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Figure 4 – High Level IRP Model Approach



IRP modeling is essentially solving the above "equation," by first looking at customer needs – both today and how these needs could evolve over time; that is, how will residential, commercial and industrial customers' electricity usage change. Then the model looks at the starting point planning resources and planning assumptions to determine the resulting capacity position and resource portfolio available before incremental optimization. This step also includes looking at alternative retirement dates for existing resources, if applicable. The model evaluates which incremental resource alternatives, if any, should be added to or otherwise modify the starting point in a manner that meets customers' needs reliably and cost-effectively. New resource alternatives may include resources that are commercially available today, like solar, wind, battery energy storage systems, as well as resources that are considered emerging and may not be fully ready for deployment today, although may be economic within the study window in five, 10, or 15 years, such as various LDES technologies, CCGT with CCS, hydrogen, or SMRs.

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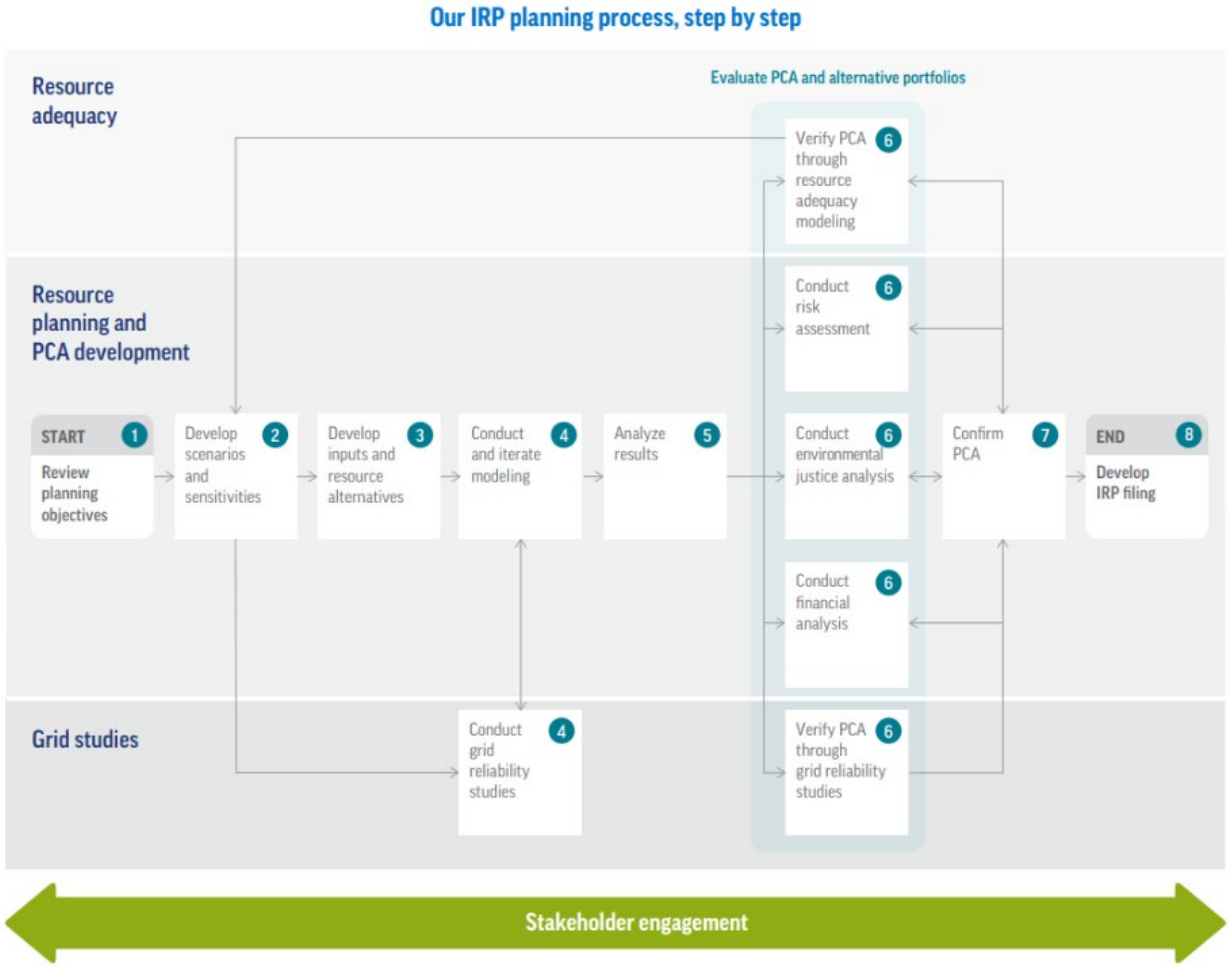
The Company then runs various scenarios and sensitivities to consider new resource alternatives that best fit the plan from a need perspective. The output of the modeling provides an "optimal or least-cost" portfolio of resources for the scenarios and sensitivities combinations, which can be compared to certain other portfolios in terms of cost, reliability, and environmental impact.

Q93. Can you describe the Company's process to create the IRP?

A93. Yes. There are numerous steps involved in developing an IRP, some of which are iterative and reliant on previous steps. At a high level, the Company's IRP process can be categorized into eight key steps with stakeholder engagement involved throughout the process. A high-level overview is depicted in Figure 5 – IRP Process Overview.

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Figure 5 – IRP Process Overview



- **Step 1**: Reviews the IRP Planning Objectives, compliance requirements, and other applicable requirements
- **Steps 2 and 3**: Includes developing the scenarios and sensitivities used in modeling as well as developing the modeling inputs, assumptions, and resource alternatives. As part of these steps, the Company determines a broad set of scenarios and sensitivities that capture a wide range of potential futures and includes the scenarios and sensitivities required. This step also develops the starting point capacity position by comparing the accredited

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capacity of existing and approved resources and other applicable planning assumptions, including known or projected changes, with the customer demand forecast plus the applicable planning reserve margin requirement (PRMR). The Company works internally to develop the inputs, assumptions, and resource alternatives that will be used in modeling.

- **Step 4**: With the inputs, assumptions, alternatives, scenarios and sensitivities, and capacity outlook determined, the Resource Planning and Transmission Modeling (RP&TM) team moves to step four. Different steps within the IRP process use various methods of modeling. The modeling conducted in the IRP is an iterative process between IRP modeling, resource adequacy modeling, and grid reliability modeling. The IRP modeling is performed using a software tool called EnCompass. The extensive IRP modeling included running various scenarios and sensitivities (called an EnCompass run), each combination resulting in a different portfolio. A portfolio represents the resource plan the model determines to be the optimal plan based on market assumptions and resource alternatives. For Resource Adequacy, the RP&TM team passes along different portfolios to understand if they would be deemed reliable. This analysis is conducted by a third party, PowerGEM, for MISO Local Regional Zone (LRZ) 7. Another step in the iterative process is grid modeling which analyzes the transmission system impacts, including the estimated costs of associated transmission network upgrades and is conducted by International Transmission Company (ITC).

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- **Step 5**: Analyzes the modeling results. Alternative portfolios under certain scenarios are compared to each other and conclusions are made to help design the PCA.
- **Step 6**: Involves the initial synthesis of results, which supports the determination of a PCA. The preliminary PCA is then further analyzed through a series of additional studies, including resource adequacy modeling, risk assessments, EJ analysis, affordability analyses, and financial analyses. If the preliminary PCA does not incorporate or satisfy one or more of these assessments, then the preliminary PCA will be adjusted and checked again to see if the criteria are met until each assessment is verified.
- **Step 7**: Results are then synthesized into what becomes the PCA. The PCA is the most reasonable and prudent option to meet the Company's energy and capacity needs at a reasonable cost compared to other alternatives and aligns with the Company's planning objectives.
- **Step 8**: The IRP filing is developed and the Company files an application with supporting testimony requesting the Commission's approval of the IRP. Per MCL 460.6t, the MPSC will conduct a contested case proceeding with recommended changes stated not later than 300 days after filing an IRP and issue a final order no later than 360 days after the filing date.

Stakeholder engagement underpins the IRP analysis and development process, which I discuss further below in my testimony. Please refer to Witness Manning's testimony for additional details regarding the IRP process.

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Q94. Can you describe what types of modeling and analyses the Company conducted to support this IRP?

A94. Yes. The Company used several modeling and analytical studies to develop the IRP. These analyses included: (1) capacity expansion and production costs modeling (typically known as "IRP modeling"); (2) transmission grid reliability and power flow studies conducted by ITC, including impacts of new generation and retirements on the transmission system; (3) resource adequacy studies including loss of load expectation (studying reliability of supply at all hours of the year under different conditions); (4) engineering studies on peaking generation; (5) environmental assessment including environmental impacts and EJ screening and analysis; (6) risk assessment evaluating how different portfolios would perform given a range of unexpected possible outcomes; and 7) financial modeling and rate impact analysis. Witness Manning provides additional detail on the types of modeling performed in the IRP including the supporting witnesses for each model or study.

While the IRP modeling helps identify least-cost portfolios to meet future energy and capacity needs based on the various assumptions, additional data and analyses are needed to formulate the PCA to account for transmission and resource adequacy impacts and ensure compliance with applicable statutory requirements, as discussed by Witness Manning. The Company looked across multiple modeling runs to identify an optimal portfolio that best aligns with the planning objectives and statutory requirements, considers stakeholder feedback, considers industry factors, and is the most reasonable and prudent option considering the reliability and affordability needs of its customers.

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Q95. Can you describe the Company's approach to ensuring electric reliability in the PCA?

A95. Yes. The PCA is designed to ensure DTE Electric can reliably serve its customers while retiring existing resources, adding new resources, and serving additional load growth. Reliability is the highest priority in the Company's planning process and the foundation of the PCA.

DTE Electric is responsible for maintaining a reliable and resource adequate supply of power to its customers. Because the Company operates as part of a broader grid, to help ensure reliability, the Company must plan for its future considering the broader energy market conditions across Michigan and the MISO region. That is why the Company has developed the IRP process to assess IRP modeling, resource adequacy modeling, and grid reliability modeling as defined above.

As discussed in more detail by Witness Manning, this comprehensive planning approach helps mitigate PCA implementation risks and maintain a reliable system for customers under various conditions.

Q96. Can you describe the differences between IRP, resource adequacy, and grid reliability modeling?

A96. Yes. The differences between IRP, resource adequacy, and grid reliability modeling are defined below.

IRP Modeling: IRP modeling is typically completed using capacity expansion models to optimize and determine what the least-cost portfolio is based on the

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economics of alternative resources, market assumptions, existing resources, and load demand. Modelers can integrate inputs and results from resource adequacy and grid reliability modeling to conduct a least-cost economic optimization analysis in the capacity expansion model. The output of the IRP model provides portfolios that are optimized for customer affordability, given emissions reduction goals and/or other constraints. Witness Manning discusses IRP modeling in her testimony.

Resource Adequacy Modeling: Resource adequacy entails the availability of sufficient resources over the planning horizon to meet forecasted demand during real-time operations considering uncertainties in generation performance, weather, and load. To determine this, resource adequacy modeling was conducted by PowerGEM for MISO Local Resource Zone 7. Witness Burgdorf explains the applicable MISO resource adequacy requirements, Witness Brooks presents the methodology and results of PowerGEM's probabilistic resource adequacy analysis, and Witness Manning explains how the Company incorporated the resource adequacy analysis into its broader resource planning process.

Grid Reliability Modeling: DTE Electric requested that ITC analyze transmission system impacts, including the estimated costs of associated transmission network upgrades, from potential coal plant retirements and replacement generation scenarios as well as interconnection costs. These costs were integrated into the IRP modeling. The Company began discussions with ITC early in the IRP process. DTE Electric developed the scenarios with guidance from ITC on what to consider based on their modeling approach and parameters. The transmission analysis focused on

Line No.

the identification of reliability issues and solutions. These efforts are further described by Witnesses Manning and Djordjevic.

Q97. Did the Company assess risk in the IRP process?

A97. Yes. The Company conducted five separate risk analyses as part of the IRP process, which included a stochastic economic risk analysis, a stochastic reliability analysis, a portfolio metric evaluation, a scenario analysis, and global sensitivity analysis. These analyses were conducted to understand the impacts of various plans and confirm the most reasonable and prudent plan for its customers. Witness Manning describes the risk analyses conducted as part of the IRP process.

Q98. How are EJ communities defined in this application?

A98. The Company applied the definition of EJ communities established in the Commission's December 18, 2025 Order in Case Nos. U-21570 and U-21867 regarding the MPSC IRP filing requirements in this filing. The requirements define EJ communities as "overburdened, vulnerable, underserved, or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen). If MiEJScreen tool is not available, the utility should work with and take feedback from Staff, EGLE, and interested parties when determining which other tool or methodology to use."

Q99. Did the Company conduct an EJ analysis?

A99. Yes. The Company conducted an EJ analysis that is aligned with the IRP filing requirements in Case Nos. U-21570 and U-21867. For each portfolio, the Company

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calculated selected emissions from each Company-owned generation facility, performed an EJ screening and assessment of air emissions, as well as the impact on water quality, waste disposal, and expected changes in land use for new or retiring resources of identified vulnerable communities, and determined health impact estimates for air emissions. Witness Marietta's testimony describes the EJ analysis and associated results.

Q100. In addition to modeling, what other key components were included in the IRP process?

A100. In addition to modeling, the Company conducted a 2025 All-Source RFP to procure replacement resources for the Monroe Power Plant following its retirements in 2028 and 2032. Beyond replacing Monroe Power Plant, the RFP accounted for changes to MISO's DLOL seasonal construct and forecasted demand. The RFP sought between 1,500 and 3,000 MW of firm MISO-accredited capacity and energy from energy storage systems and clean energy systems as defined in MCL 460.1003 and further discussed in Part II of my testimony. DTE Electric accepted contract structures in the form of build transfer agreements (BTAs), purchase and sale agreements (PSAs), tolling agreements (TAs), or power purchase agreements (PPAs) with a commercial operation date (COD) between January 1, 2030, and December 31, 2032. Witness Pratt describes the RFP and its associated results.

Stakeholder Engagement & Public Outreach

Purpose and Requirements

Q101. What direction has the MPSC given to utilities regarding stakeholder engagement in the IRP development process?

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A101. In the December 18, 2025 Order approving the IRP Filing Requirements and Planning Parameters in Case Nos. U-21570 and U-21867, the MPSC encourages early participant engagement in the development of the IRP to: "(1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resources plan; (4) encourage robust and informed dialogue on resource decisions; (5) reduce utility regulatory risk by building understanding and support for utility resource decisions; and (6) ensure the inclusion of diverse voices, including environmental justice communities and Tribal Nations."

Q102. How should the feedback received during the participant engagement process be used?

A102. The IRP Filing Requirements approved by the Commission in its December 18, 2025 Order in Case Nos. U-21570 and U-21867 states, "the utility should incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing."

Q103. Are there other recommendations for engaging interested parties, such as intervenors and MPSC Staff, in the IRP planning process?

A103. Yes. For interested parties, such as intervenors and MPSC Staff, the IRP Filing Requirements approved in Case Nos. U-21570 and U-21867 state, in part, "In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants…A minimum of two engagement workshops is recommended. An engagement workshop will give interested persons an opportunity to provide input regarding the utility's assumptions, inputs, and

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modeling methodologies employed during the development of the IRP…The utility is encouraged to invite interested persons, including expected intervenors, and the Staff, to its engagement workshops."

Q104. Per Case Nos. U-21570 and U-21867, what are the requirements for engaging the public in the IRP planning process?

A104. In regards to engaging the public, the IRP Filing Requirements approved in the Order continues, "[i]f the engagement workshops are not open to the public, two additional hybrid public meetings with the option for both virtual and in-person attendance are recommended…The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment…Advanced notice should be provided to customers in the utility's service territory. This should include Tribal governments, local governments, and community-based organizations."

Q105. Did the Commission provide additional requirements for engaging EJ Communities in the IRP planning process?

A105. Yes. The IRP Filing Requirements approved in Case Nos. U-21570 and U-21867 further state, "If 5% or greater of a utility's residential customers are in communities identified as part of the EJ analysis, it is recommended that at least one of the two additional hybrid public meetings are located in any of the identified communities…The public meetings should be offered in the utility's service territory in geographic locations that are convenient for customers, prioritizing accessibility and convenience for customers identified in the EJ analysis."

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Q106. Are there requirements for engaging Tribal Nations?

A106. Yes. In addition to the advanced notice of public meetings to Tribal governments mentioned in the testimony above, the IRP Filing Requirements approved in the Order in Case Nos. U-21570 and U-21867 state, "The utility shall invite all Tribal Nations with tribal lands in their service territory and provide a point of contact with a local utility engagement specialist that can address how the IRP and CEP may impact tribal lands."

Q107. Per Case Nos. U-21570 and U-21867, what are the requirements for documenting and reporting IRP stakeholder engagement?

A107. The requirements include, "[d]ocumentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing and the utility is encouraged to share these documents with the public. Documentation should include:

a) Workshop dates and times, including times outside of the workday;
b) Evidence that a notice of the workshops was provided to the public;
c) Meeting minutes;
d) Meeting or workshop attendance lists;
e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application;
f) Description of how the public outreach process influenced the IRP;
g) Description of community outreach efforts for environmental justice communities and tribal lands within the Company service territory. Environmental justice communities should be identified using the MiEJScreen Tool."

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They further state, "[i]f the utility chooses to hold pre-filing workshops, including engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any prefiling workshops, and shall file the report with the IRP application. All presentations, recordings, comments, and transcripts from those presentations open to the public should be maintained on a website in a location open to the public for the duration of the outreach process and the duration of the IRP case, until a final commission order is published."

Q108. Did the Company make any commitments for additional EJ community engagement?

A108. Yes. In its 2022 IRP Settlement Agreement (Case No. U-21193), the Company agreed to:

- Develop an outreach and engagement plan for its next IRP specific to "Overburdened Communities" as that term is defined in the October 27, 2022 order in Case No. U-18461;
- Seek input from community-based organizations on the proposed outreach and engagement plan, including coordination with community-based organizations when organizing and promoting meetings about the IRP;
- Solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord; and
- Begin implementation of the outreach plan within two years of the next IRP and include the outreach and engagement plan, the feedback received, and discussion on how the feedback and learnings were considered by the Company in the IRP process.

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A description of how the Company met these requirements is detailed below.

The Company's Stakeholder Engagement Approach

Q109. How did the Company approach stakeholder engagement?

A109. The Company conducted early, accessible, and transparent engagement with a broad range of stakeholders as part of its IRP development process. To ensure the approach was effective for different audiences, the Company structured its engagement around two groups: (1) customers, including enhanced outreach for customers in EJ Communities, and (2) technical stakeholders.

The Company's stakeholder engagement approach for customers and communities, including outreach to EJ communities, was conducted through a public engagement plan developed beginning in November 2024 and implemented from April 2025 through February 2026. Engagement activities included eleven community-based engagements, three information sessions, a "Voice of the Customer" survey, four public meetings, and online resources including the IRP website[38] and blog.[39] Nearly 2,000 customers were directly engaged through these efforts.

Q110. What was the purpose of the public engagement plan?

A110. The purpose of the public engagement plan was to educate customers, including customers in EJ communities, and other community stakeholders on the IRP process, and to gather their input through an accessible and transparent approach.

[38] DTE Energy, CleanVision Integrated Resource Plan website. https://dtecleanenergy.com/. Accessed August 24, 2026.
[39] DTE Electric, Help Shape Michigan's Energy Future, Empowering Michigan. September 22, 2025. https://empoweringmichigan.com/2026-cleanvision-integrated-resource-plan-public-meetings/. Accessed August 24, 2026.

Line No.

The public engagement plan was informed by early consultation with community, local government, and State of Michigan leaders serving EJ communities and was shared with MPSC Staff and technical stakeholders. Moreover, the public engagement plan was aligned with DTE Electric's enterprise-wide planning objectives: Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean. (See Figure 3).

Q111. Can you provide an overview of the public engagement activities the Company provided?

A111. Yes. For an overview of the engagement activities see Table 2 below.

Table 2 Summary of Public Engagement Activities

Type of Outreach	**Details**			
Community-based engagements	***Type***	***Date***	***Location (*indicates EJ community)***	***# Engaged on IRP***
Community open houses - Grassroots community events aimed at increasing awareness of DTE investments and programs, understanding customer experiences with their electric service, and creating opportunities for in-person dialogue and feedback	In Person	5/14/25	Farmington / Farmington Hills	21
	In Person	6/17/25	Westland*	26
	In Person	8/14/25	Royal Oak / Oak Park* / Madison Heights*	50
	In Person	9/10/25	Dearborn* / Dearborn Heights*	17
	In Person	9/18/25	Ypsilanti*	31
	In Person	10/9/25	Livonia / Redford*	18

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Type of Outreach	Details			
	In Person	11/17/25	Canton / Belleville	27
Customer resource fairs - Community, in-person events to help DTE customers access energy assistance programs and other resources	In Person	4/2/25	Highland Park*	11
	In Person	10/30/25	Detroit*	21
Community presentations - Additional opportunities to engage community members on the IRP through a presentation or interactive workshop	In Person	5/15/25	Pontiac*	109
	In Person	7/30/25	Detroit*	19
Information sessions (also referred to as Powering Michigan series)	***Type***	***Date***	***Location***	***Live Participants***
Recorded sessions to educate customers on the energy system, provide transparency into the DSP and IRP processes, and solicit feedback	Virtual	10/1/25	N/A	15
	Virtual	10/20/25	N/A	20
	Virtual	11/3/25	N/A	10
Voice of the Customer survey	***Type***	***Dates***	***Location***	***Respondents***
Third-party conducted quantitative research with residential customers, business customers and community stakeholders to understand energy priorities, resource preferences and evolving perspectives since 2022 IRP survey	Virtual	8/7/25 through 8/25/25	DTE Electric's service territory	1,510
Public Meetings (also referred to as Community Conversations)	***Type***	***Date***	***Location (*indicates EJ community)***	***Participants***

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Type of Outreach	Details			
Facilitated, in-depth conversations designed to understand customers' priorities around reliability, affordability, and clean energy, as well as any existing concerns. IRP and DSP teams worked in collaboration with community-based organizations and a third-party consultant to plan and conduct meetings	In Person	11/12/25	Dearborn*	12
	In Person	12/4/25	Monroe*	18
	In Person	1/22/26	Detroit*	13
	Virtual	2/17/26	N/A	2
			Total customers engaged	1,950

Q112. How did the Company share information about its IRP public engagement activities?

A112. In support of the public engagement activities, the Company maintained IRP information on the IRP website, dtecleanenergy.com, the "Help shape Michigan's Energy Future" page of the Company's Empowering Michigan blog (IRP blog), and DTE Energy's YouTube page,[40] which hosted the recordings for the information sessions. From September 21, 2025, through August 31, 2026, the IRP website had over 12,800 total users and the IRP blog, which included the dates and times of information sessions and public meetings, had over 850 total users. As of September 1, 2026, the three Information Session recordings collectively have been viewed nearly 800 times.

Q113. How did the Company engage with technical stakeholders?

[40] DTE Electric Integrated Resource Plan YouTube Channel, available at https://www.youtube.com/playlist?list=PL71KJznAwXEkfKQmUf9-VqRQNdoRNCdnX. Accessed September 7, 2026.

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A113. In parallel with the public engagement plan, the Company implemented a structured technical stakeholder engagement process to support transparency and incorporate input on key modeling assumptions, scenarios, and analytical approaches used in the 2026 IRP. For purposes of the 2026 IRP, technical stakeholders include individuals with expertise in IRP development, modeling, and electric system planning, as well as organizations that regularly participate in DTE Electric's regulatory proceedings. Between October 2025 and June 2026, the Company conducted five technical workshops—one hybrid and four virtual—to provide timely information, facilitate discussion, and solicit stakeholder feedback. Feedback received during these workshops informed subsequent workshop agendas and ongoing IRP development.

Q114. How did the Company document its stakeholder engagement process and ensure the public's access to any engagement materials?

A114. In accordance with the IRP filing requirements, the Company has prepared the DTE Electric Public Outreach Report (Public Outreach Report) detailing and documenting its stakeholder engagement process, the feedback received, and how that feedback was considered (see Exhibit A-1.6). In addition, workshop dates and times, public outreach presentations, recordings, and transcripts were posted and remain available to the public on the "Help shape Michigan's energy future" page of the Company's IRP blog.[41]

[41] DTE Electric, Help Shape Michigan's Energy Future, Empowering Michigan. September 22, 2025. https://empoweringmichigan.com/2026-cleanvision-integrated-resource-plan-public-meetings/. Accessed August 24, 2026.

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Identification of Tribal governments & EJ Communities

Q115. Are there any Tribal governments whose land base or service territory overlays with the Company's service territory?

A115. No. In response to the requirement to extend outreach to the Tribal Nations, the Company consulted with EGLE and compared its DTE Electric service territory map with the U.S. EPA Region 5 map depicting Indian Lands and with a Michigan Tribes' Service Area list maintained by EGLE's Tribal Relations office. Based on this analysis, the Company determined there was no overlay of Tribal governments with its electric service territory and therefore conducted no additional outreach.

Q116. How were EJ Communities identified in the public engagement planning process?

A116. For purposes of EJ community engagement, in November 2024, the Company used the MiEJScreen 1.0 tool to identify census tracts within DTE Electric's service territory at or above the 75th percentile in MiEJScreen, consistent with the threshold subsequently adopted in the Commission's revised IRP Filing Requirements.[42] Focusing on some of the highest MiEJScreen scores and further considering population density, geographic and demographic diversity, and community proximity to DTE Electric's power plants, the Company identified the following cities for enhanced EJ community engagement: Dearborn, Detroit, Highland Park, Monroe, Pontiac, and Ypsilanti. Although the Company engaged with numerous communities during the IRP planning process, the public engagement plan was

[42] MPSC, Case Nos. U-21867 and U-21570, December 18, 2025 Order, Ex. B, Revised Integrated Resource Plan Filing Requirements, p. 8. The Filing Requirements define "Environmental Justice Communities" as overburdened, vulnerable, underserved, or disadvantaged communities identified, for purposes of the analysis, by a minimum percentile of 75 in MiEJScreen.

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intentionally designed to ensure that each targeted EJ Community had an opportunity for direct engagement.

EJ Community Feedback on Public Engagement Plan

Q117. When and how were EJ Community leaders engaged in the development of the public engagement plan?

A117. In November 2024, the Company began meeting virtually with leaders from 25 community, local government, and State of Michigan organizations representing or advocating for EJ Communities (EJ Community Leaders). These EJ Community Leaders provided input on how to effectively conduct outreach and engagement in their communities.

Q118. What input did the EJ Community Leaders provide?

A118. The EJ Community Leaders advised that the Company's IRP engagement should also include issues prioritized by communities, such as affordability, reliability, grid investments, clean energy, and jobs. They also recommended providing customers with plain language explanations about how the IRP is the Company's plan for how it will generate power five, 10, and 15 years into the future; how the IRP impacts customers' daily lives, and how customer feedback would be considered in the planning process. In addition, they encouraged the use of inclusive and accessible outreach methods, including in-person and community-based engagement, diverse communication channels, multilingual materials, and support services to reduce barriers to participation.

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Q119. How did the Company incorporate the feedback received from EJ Community Leaders?

A119. In response to this feedback, the Company increased the accessibility of the public engagement plan for EJ Communities in the following ways:

- IRP engagement included information and resources on topics prioritized by EJ Communities, such as affordability, reliability, grid investments, and clean energy;
- The Company coordinated combined IRP and DSP outreach activities, thereby addressing customer distribution reliability concerns;
- The Company developed plain-language information sessions to educate customers on the energy system, the IRP and DSP planning processes, how these processes affect customers, and how stakeholder input would be considered;
- Engagement activities were held outside of standard work hours and in convenient, community-based locations;
- Materials and presentation transcripts were made available in multiple languages (English, Spanish and Arabic), and virtual sessions included live language translation and closed captioning; and
- In-person events offered meals, language translation, and support for individuals with disabilities.

Community-based Engagements

Q120. What are some ways that the Company regularly engages with customers?

A120. The Company is committed to regular engagement with customers, communities, and local governments to communicate updates and gather feedback throughout the

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year. A more detailed description of the Company's ongoing community and customer engagement can be found in DTE Electric's 2026 DSP in Case No. U-22104. Several times per year, the Company hosts community open houses across its service territory where subject matter experts share information and answer customer questions on topics such as local reliability investments, energy efficiency programs, and utility assistance resources.

Customer resource fairs are another key component of the Company's ongoing community outreach. These day-long events focus on communities with a high concentration of customers who may benefit from utility assistance programs and other supportive services.

Q121. How did the Company leverage these community open houses and customer resource fairs to engage community members and gather feedback on the 2026 IRP?

A121. In 2025, the Company staffed an IRP information table at community open houses and customer resource fairs. Using posters and plain-language materials, Company representatives provided interested customers with an overview of the energy system, the IRP planning process, and the Company's 2022 IRP. Customers were then invited to identify their top three priorities for the 2026 IRP by using a dot-voting process in response to two questions: (1) which topics should be the highest priority for DTE Energy over the next five years; and (2) which topics should be the highest priority as part of the Company's clean energy transition.

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Q122. In addition to community open houses and customer resource fairs, did the Company undertake additional community-based engagements for the 2026 IRP?

A122. Yes. The Company conducted two targeted community presentations on the IRP process. These included a presentation to older adults in Pontiac and an interactive workshop with young adults participating in a City of Detroit-sponsored summer workforce program. Hearing from customers in different age groups reflects a best practice in community outreach by ensuring that feedback captures a broader range of customer experiences, needs, and perspectives.

Q123. Which of these community-based engagements occurred in EJ Communities?

A123. Collectively, the community-based engagements reached ten EJ Communities which included: Dearborn, Dearborn Heights, Detroit, Highland Park, Madison Heights, Oak Park, Pontiac, Redford, Westland, and Ypsilanti.

Q124. What were the key findings from the community-based engagements?

A124. Customers most frequently identified affordability, reliability, and grid modernization as their top three priorities for DTE Energy over the next five years. Affordability was emphasized more strongly by participants at customer resource fairs, where attendees were actively seeking energy assistance. In response to the second question on the Company's clean energy transition, customers most frequently identified energy efficiency and the addition of renewable energy resources as top priorities. Investments in battery storage ranked as the third most frequently selected priority.

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Customers participating in the IRP community presentation for older adults largely focused on distribution reliability questions such as tree-trimming. Several participants asked questions regarding solar power and electric vehicles. The community presentation for young adults in Detroit was conducted as an interactive workshop. While these participants did not provide direct feedback on the 2026 IRP, they did engage in an exercise exploring the benefits and trade-offs of generation resources and various hypothetical plans.

Information Sessions

Q125. What was the purpose of the information sessions, and how were they conducted?

A125. The information sessions, also referred to as the "Powering Michigan" series, consisted of three virtual educational webinars conducted in coordination with the Company's Distribution Operations team. To help customers understand how the electric system works, the first information session provided a high-level overview of the electric system and both the IRP and DSP planning processes, while the subsequent sessions provided more detailed information on the DSP and IRP, respectively.

Q126. What feedback did participants provide during the information sessions?

A126. Customers had the opportunity to participate in a live question-and-answer segment following the Company's presentation. During the question-and-answer segment for the first session, questions focused on how rooftop solar was incorporated into the IRP and the ownership models for renewable energy resources in the plan. There were no questions posed during the second session's presentation on the

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DSP. In the third session, participants raised questions about how data center demand and climate change research would be treated in IRP modeling.

Q127. How did the Company make the information sessions more accessible to customers?

A127. To reach a broader audience, the information sessions were virtual, scheduled after standard work hours, and offered live language transcription and closed captioning via Microsoft Teams. The IRP blog provided participation details for the information sessions. Once these events concluded, the presentations, recordings, and transcripts (in English, Spanish, and Arabic) were made available to the public on the IRP blog. These materials will remain available to the public on the IRP blog throughout this proceeding.

Q128. Why was the DSP process included in the information sessions and other engagement activities?

A128. As noted above, the EJ Community Leaders emphasized that IRP engagement should address the issues most important to customers, including distribution reliability. Concurrently with the IRP planning process, the Company was developing its 2026 DSP. Coordination between the IRP and DSP teams for both the information sessions and public meetings (described below) enabled the Company to respond directly to customer priorities and efficiently provide a more integrated public engagement approach.

Voice of the Customer Survey

Q129. What customer research did the company conduct specific to the IRP?

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A129. The Company engaged Purple Strategies, a third party, to conduct a quantitative "Voice of the Customer" survey with residential customers, business customers, and community stakeholders. The survey repeated several resource planning questions from the 2022 IRP survey, providing a consistent basis to compare customer and stakeholder energy priorities and resource preferences over time. The survey also sought to gain insights into how the Company should approach IRP engagement.

Q130. When was the Voice of the Customer research conducted and what was the methodology?

A130. The survey was conducted from August 7, 2025, through August 25, 2025. Purple Strategies identified the survey sample and administered the survey to DTE Electric's residential and business customers. In addition, the Company invited 2,200 community stakeholders—representing local governments, community-based organizations, EJ advocacy groups, and faith-based organizations—to participate via email. The total number of survey respondents was 1,510, which included 1,211 residential customers, 200 commercial and small business customers, and 99 community representatives.

Q131. What were the key findings from the Voice of the Customer research?

A131. The key findings from the survey were:

- Affordability and reliability remain top priorities across all stakeholders, while environmental issues like net zero are less strongly emphasized than in 2022.

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- Reliability is defined as "keeping the lights on" related to grid infrastructure and outage prevention, not energy mix or generation sources.
- Compared to the 2022 survey, support for renewables remains high but enthusiasm has softened, especially among commercial customers, while openness to energy storage, nuclear, and natural gas resources has grown.
- Many expect bills to rise with future investments. Residential and commercial customers are somewhat open to modest increases, while community representatives remain less tolerant.
- To address concerns about outages and costs, community representatives want to actively engage with the Company through regular updates, meetings, and program feedback, and they expect the Company to maintain strong communication with local governments and organizations.

Public Meetings

Q132. How many public meetings were held and how were the locations selected?

A132. The Company coordinated efforts across IRP and DSP initiatives on three public meetings in EJ communities, also referred to as "Community Conversations." As described above, the Company used the State of Michigan's MiEJScreen 1.0 to identify EJ Communities within its electric service territory. The Company then considered additional factors, including DTE Electric power plant locations, geographic diversity, community characteristics, and opportunities to partner with community-based organizations in selecting final meeting locations. Based on this approach, the Company selected Detroit, Dearborn, and Monroe as locations for its three in-person sessions and offered a fourth, virtual session as an additional participation option.

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Q133. Did the Company collaborate with third parties to support the public meetings?

A133. Yes. The Company collaborated with the consulting firm Public Sector Consultants to design and facilitate the public meetings. As a best practice, the Company used this third-party consultant to create a neutral forum where participants could speak more openly and stakeholder input could be gathered and documented independently.

In addition, three community-based organizations—ACCESS (Arab Community Center for Economic and Social Services), United Way of Monroe/Lenawee Counties, and La Sed (Latin Americans for Social and Economic Development)—were engaged to host the public meetings, engage the community to participate and advise on meeting locations, scheduling, engagement strategies, and community-specific considerations.

Q134. How did the Company notify the public in advance of the public meetings?

A134. Public Sector Consultants created registration pages for each public meeting with translation options for the page available in Spanish and Arabic. The Company shared links to the registration pages through various methods including: the IRP blog, targeted social media advertising, a DTE community stakeholder newsletter, and direct email communication to more than 57,000 customers. The community-based organizations hosting the public meetings also performed community outreach to further raise awareness and encourage participation.

Q135. How were the public meetings conducted?

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A135. Each session followed a consistent format. The Company began with an overview of the energy system, as well as the IRP and DSP. Participants were then provided an opportunity to ask questions before transitioning to facilitated breakout discussions led by Public Sector Consultants. These discussions focused on three key topics: electric reliability, cleaner energy, and affordability. Each topic included a primary question and supporting prompts to guide discussion.

Participant feedback was documented during the sessions and subsequently reviewed and prioritized by participants using a structured dot-voting process. A detailed description of the meeting methodology and summary of participant input is provided in Public Sector Consultants' report titled, Environmental Justice Community Engagement for DTE Energy's Integrated Resource Plan and Distribution System Plan (included in Exhibit A-1.6).

Q136. What steps did the Company take to ensure that the meetings were accessible to those with disabilities (including those that are hearing and visually impaired), those whose first language is not English, and to EJ Community members?

A136. The Company ensured the public meetings were accessible by:

- Hosting the meetings within EJ Communities and where many residents speak languages other than English;
- Scheduling the meetings after standard work hours and providing dinner;
- Allowing participants to request accommodations during registration to support their participation;

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- Providing meeting registration in multiple languages and arranging for language translation services at the meeting;
- Utilizing facilities that were wheelchair accessible and requiring microphones to improve audibility;
- Providing additional in-person customer service support to address individual participant questions or needs; and
- Including a virtual public meeting option with closed-captioning and live language transcription.

Q137. What were the key findings from the public meetings?

A137. While feedback varied across communities, several consistent themes emerged from the public meetings. First, participants placed a strong emphasis on distribution reliability, including grid modernization and tree trimming. Participants also identified the need for more frequent and transparent communication, particularly regarding outages, rates, and emerging issues such as data centers. Although the transition to cleaner energy was discussed at all three in-person meetings, levels of support varied across the three communities. Finally, participants expressed interest in additional Company support for vulnerable customers.

Q138. How did the Company share the public meeting materials with the public?

A138. Once the public meetings concluded, the presentations were made available on the IRP blog and will remain available to the public throughout this proceeding.

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Additional Sources of IRP Information and Feedback

Q139. What other sources of IRP information were made available to the public?

A139. The Company provided additional IRP information to the public through the IRP website and the IRP blog.

The IRP website, originally launched in 2022 and updated in 2025, provides the public with information on the Company's 2022 Integrated Resource Plan, the purpose of integrated resource planning, and the Company's 2026 IRP development process.

The IRP website, event invitations, and other communications also directed customers to the IRP blog. During the planning process, the IRP blog provided registration details for the information sessions and public meetings. Once these events concluded, the presentations, recordings, and transcripts were made available to the public on the IRP blog. These materials will remain available to the public on the IRP blog throughout this case.

Q140. In addition to the activities outlined above, what other opportunities were there for the public to provide feedback on the IRP process?

A140. Customers and other stakeholders were invited to provide feedback via email and/or through submission of a comment using an electronic comment form. The email address and comment form link were featured in presentations and on the IRP website and IRP blog.

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Q141. What feedback has the Company received via email and the electronic comment form?

A141. All stakeholders, public and technical, were invited to provide feedback via email and/or through submission of a comment using an electronic comment form. The IRP email address and comment form link were featured on the IRP website, IRP blog, and meeting presentations. Since January 1, 2025, the Company received seven comments from customers. The Company responded to all questions and comments regardless of their relationship to the 2026 IRP. IRP-related feedback included a question regarding the inclusion of lithium iron phosphate batteries in resource planning and a comment related to data center demand's impact on resource planning. In addition, the IRP email address was used by the Company to communicate with technical stakeholders about upcoming workshops.

Impact of Public & EJ Stakeholder Feedback

Q142. How did the feedback received during the public engagement process influence the IRP?

A142. The public engagement process directly informed the Company's 2026 IRP by providing clear insight into customer priorities, confirming the public's interest in learning about the Company's plans while also identifying the most impactful methods for stakeholder engagement.

Customer feedback across all IRP engagement methods emphasized reliability and affordability as the consistent top priorities. Stakeholders also continued to support cleaner energy resources, while being open to a more diverse resource mix including energy storage, nuclear, and natural gas.

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In terms of reliability, customers primarily associate reliability with distribution-related issues, such as outage prevention. The Company recognizes this as an opportunity to further communicate with customers on the relationship between generation resources, long-term planning, and reliable electricity.

In terms of affordability, customers anticipate the cost of electricity to increase as the Company transitions to cleaner energy resources. However, customers expressed different sensitivities to bill impacts, with customers from EJ communities prioritizing affordability over reliability and cleaner energy.
In alignment with these customer priorities, the Company designed a resource plan that prioritizes maintaining reliable service and managing customer costs while continuing to advance the transition to a cleaner, more diverse energy portfolio, including renewable energy, storage, and other technologies. The Company will also continue to educate customers on the relationship between generation resource planning and reliable electricity.

Customers also provided both direct and indirect feedback on the Company's engagement practices, emphasizing the importance of transparent, frequent communication, particularly regarding outages, rates, data center demand, and the potential customer impacts of the IRP. The Company will continue listening to customers' feedback about the importance of communications regarding reliability and will explore opportunities to address through future collaboration with the Distribution Operations and Distribution System Planning teams. Indirectly, the Company observed low customer participation in virtual presentations and public meetings and stronger customer engagement in shorter, community-based

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activities, such as Company community open houses. These in-person events allowed customers to participate within their own communities, after standard work hours, for the duration they chose, and to focus on the topics most relevant to them. Given this feedback, the Company will continue to leverage in-person community-based opportunities for future engagement in addition to traditional communication digital channels (such as DTE website, blogs, social media, and news media).

Technical Stakeholder Outreach

Q143. Who were considered technical stakeholders for purposes of the 2026 IRP?

A143. Technical stakeholders include individuals and organizations with a more technical understanding of IRP development, modeling, and electric system planning, as well as organizations that regularly participate in DTE Electric's other regulatory proceedings.

Q144. What was the purpose of the Company's technical stakeholder workshops?

A144. Between October 2025 and June 2026, the Company conducted five technical stakeholder workshops to support a transparent decision-making process for resource planning and to ensure participants had the opportunity to provide input and stay informed regarding modeling assumptions, scenarios, sensitivities, and the overall IRP development approach.

Q145. How were technical stakeholders invited to participate?

A145. Technical stakeholders received direct email invites describing the purpose and scope of each workshop and included the meeting date, time, and virtual

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participation details. The technical workshop dates, times, and agenda topics are summarized in Exhibit A-1.6 – DTE Electric Public Outreach Report.

Q146. How did the Company determine who to invite to the technical stakeholder workshops?

A146. The Company invited participants to the technical stakeholder workshops based on parties that participated in DTE Electric's 2022 IRP Stakeholder workshops and intervened in Case No. U-21193 regarding DTE Electric's 2022 IRP. As additional stakeholders contacted the Company requesting to be included, they were added to the technical stakeholder distribution list and invited to subsequent workshops. More than 50 organizations were invited to participate in the technical stakeholder workshops via direct email invitations. Workshop presentation materials and a list of participating organizations are included in Exhibit A-1.6 – DTE Electric Public Outreach Report.

Q147. How were the technical stakeholder workshops conducted?

A147. Each technical workshop consisted of a presentation followed by a question-and-answer session led by subject matter experts from across DTE Electric, including representatives from the RP&TM, Long-term Generation Strategy, DR, Corporate Energy Forecasting, Distribution Operations, EWR, Renewables, and Environmental Strategy teams as well as external industry and technical experts, such as representatives from YES Energy, Siemens, Vote Solar, the Electric Power Research Institute (EPRI), ITC, and PowerGEM. The workshop format enabled participants to ask questions and hear responses in a shared forum, supporting transparency, consistent information sharing, and open dialogue among attendees.

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Technical stakeholder questions and comments were addressed during the workshops, with follow-up responses provided to participants after the workshops, as appropriate. Presentation materials were also distributed to all workshop invitees following each session to support continued stakeholder review and engagement. Between workshops, stakeholders were encouraged to submit additional feedback to the Company via email at DTE_Electric_CleanVision@dteenergy.com.

Q148. How did initial technical stakeholder feedback inform subsequent workshops?

A148. During the initial technical workshop, the Company received feedback from technical stakeholders through workshop discussions, email submissions to DTE_Electric_CleanVision@dteenergy.com, and comments submitted through dtecleanenergy.com on topics and areas of interest, which helped inform the agendas and focus areas for subsequent workshops. The initial workshop was conducted in a hybrid format, with the remaining workshops held virtually via Microsoft Teams to maximize accessibility and participation.

Q149. Can you provide an overview of the technical workshops conducted between October 2025 and June 2026 in advance of the IRP Filing?

A149. Yes. Table 3 describes the technical workshops conducted between October 2025 and June 2026.

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Table 3 Technical Workshop Overview

Workshop	Date	Topics included	Format: Attendees
1	10/22/2025	**IRP Process Overview & Prior IRP Context**: 2022 IRP, regulatory and industry changes, 2025 All-Source RFP overview, and stakeholder engagement plan	Hybrid 79 (est.)
2	12/11/2025	**DG / DER Assumptions:** industry experts' perspective on DG/Distributed Energy Resources (DER), DG/DER development and assumptions, DER integration considerations, modeling treatment of DG, DR, and EWR	Virtual 65
3	1/29/2026	**Demand & Technology Assumptions:** load forecasting process, EWR assumptions and sensitivities, and technology assumptions	Virtual 96
4	3/19/2026	**Supporting Models & Analyses:** supporting models (EnCompass, SERVM), resource adequacy, and environmental justice	Virtual 99
5	6/23/2026	**Overview of Key Inputs & Emerging Insights**: transmission planning process and approach (ITC), IRP requested sensitivities, updated technology cost assumptions, and industry and commodity pricing trends overview (Siemens)	Virtual 103

Q150. How did the technical stakeholder feedback impact the IRP process?

A150. Technical stakeholder feedback was incorporated throughout the IRP development process and helped inform several aspects of the Company's planning and analysis, including:

- Identifying topics of interest and questions that helped shape subsequent technical workshop agendas and discussions;

Line
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- Reviewing data inputs presented during technical workshops and providing comments, questions, and feedback that were considered as part of the IRP analysis;
- Supporting the development and evaluation of IRP scenarios and sensitivities. As discussed in the testimony of Witness Manning, stakeholder input was considered together with IRP filing requirements and internal planning considerations, in developing scenarios and sensitivities evaluated as part of the IRP analysis; and
- Providing feedback and recommendations for Company consideration throughout the IRP process, as further described in testimony of Witness Manning.

PART V: IRP MODELING RESULTS & SELECTION OF PCA

IRP Modeling Results

Q151. What are the modeling scenarios the Company evaluated in this IRP?

A151. The Company evaluated three scenarios, including the required MIRPP Scenario 1 and the optional MIRPP Scenario 2 established in Case Nos. U-21570 and U-21867, and one Company-developed scenario referred to as the Reference Case. Table 4 provides a high-level description of each scenario, and Witness Manning explains the scenarios and their use in IRP modeling.

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Table 4 Modeling Scenarios Evaluated

Scenario	Description	Purpose
Reference *(REF26)*	• Based on the Company's internal planning view using Siemens' Fall 2025 Reference Case update • Incorporates announced retirements, approved resource additions through 2030 • Includes Siemens natural gas price forecasts, and Eastern Interconnect market modeling	Primary planning scenario reflecting the Company's internal planning assumptions and used to evaluate resource needs and potential future resource additions
MIRPP1	• Aligned with MISO Future 3 and higher levels of electrification • Assumes achievement of utility and state clean energy goals across the MISO region, accelerated thermal and nuclear retirements • Uses 2025 EIA natural gas forecast	Required MIRPP scenario used to evaluate resource needs under a future with higher electrification and accelerated retirements and clean energy transition assumptions
MIRPP2	• Aligned with MISO Future 1, reflecting a more moderate transition of the generation fleet and energy demand relative to Future 3 • Assumes utility-announced retirements, continued renewable and storage growth consistent with state requirements • Uses 2025 EIA natural gas forecast	Optional MIRPP scenario used to evaluate resource needs under a more moderate transition of the generation fleet and electrification growth

Q152. What are the modeling sensitivities the Company evaluated in this IRP?

A152. The Company modeled several sensitivities including those required in Case Nos. U-21570, U-21867, U-21193, and U-21662, as well as additional sensitivities developed by the Company. These sensitivities were applied across one or more scenarios, with most evaluated under all three scenarios. Table 5 summarizes the

Line
No.

sensitivities evaluated for each scenario. Additional details regarding these sensitivities are provided by Witness Manning.

Table 5 Modeling Sensitivities Evaluated

No.	Sensitivity Description	Reference	MIRPP 1	MIRPP 2
1	Base Case / Starting Point	✓*	✓*	✓
2	Non-Dispatchable Monroe Alternative	✓*	✓	✓
3	Biomass Power Purchase Agreement	✓	✓	✓
4	Biomass Power Purchase Agreement – 5 Year	✓	✓	✓
5	Small Modular Reactors in 2034	✓	✓	✓
6	Long-Duration Energy Storage in 2032	✓	✓	✓
7	No Hydrogen Combustion Turbines	✓	✓	✓
8	No Build – Energy and Capacity Replacement	✓	✓	✓
9	Three-Times Renewable and Storage Build	✓	✓	✓
10	High Extended Power Uprate Costs	✓	✓	✓
11	No Battery Constraint	✓	✓	✓
12	Low Battery Storage Costs	✓	✓	✓
13	Production/Investment Tax Credits Return for Renewables	✓	✓	✓
14	550 MW of New Wind per Year	✓*	✓	✓
15	20% Renewable Reduction for Six Years	✓	✓*	✓
16	Land-Based Renewables Capped at 60%	✓	✓*	✓
17	No Compressed-Air Energy Storage	✓	✓	✓
18	Distribution Connected Solar	✓	✓	✓
19	Virtual Power Plants Optimization	✓	✓	✓
20	Demand-Side Management	✓	✓	✓
21	2.17% Energy Waste Reduction	✓	✓*	✓
22	2.5% Energy Waste Reduction	✓	✓*	✓
23	Optimized Energy Waste Reduction	✓		✓
24	10% Distributed Generation		✓*	
25	15% Distributed Generation		✓*	

No.	Sensitivity Description	Reference	MIRPP 1	MIRPP 2
26	20% Distributed Generation		✓*	
27	Retire Monroe Units 1 and 2 in 2030	✓*	✓	✓
28	Greenwood Retires in 2045	✓	✓	✓
29	Low Load Growth	✓		✓
30	High Load Growth	✓		✓
31	Low Large Load Growth	✓	✓*	✓
32	Low Large Load Growth + 90% Renewables	✓	✓	✓
33	Low Large Load Growth + Energy Purchase	✓	✓	✓
34	Medium Large Load Growth	✓	✓*	✓
35	High Large Load Growth	✓	✓*	✓
36	Customer Choice Return	✓		✓
37	Atypical Weather Conditions	✓	✓*	✓
38	High Natural Gas Price	✓	✓*	✓
39	Combined Cycle Gas Turbine Costs + 10%	✓	✓	✓
40	Without Google	✓*		
41	Without OACS and Google	✓*		
42	2026 Final Proposed Course of Action	✓*	✓*	✓
43	2022 Integrated Resource Plan Portfolio	✓	✓*	✓
	Total Sensitivities	40	37	38

✓ = Sensitivity included in scenario
✓ * = Required sensitivity (regulatory or settlement requirement)

Q153. Do the scenarios and sensitivities evaluate a broad range of planning uncertainties and potential future conditions?

A153. Yes. Taken together, the scenarios and sensitivities test how changes in key planning assumptions could affect future resource needs, portfolio costs, and the resources selected by the model. The Company evaluated uncertainties including:

- **Demand**: various assumptions affecting demand, including higher and lower load growth, electrification, large loads, atypical weather, and customer choice
- **Demand-side resources:** alternative levels and availability of EWR, distributed generation, demand response, and VPPs

Line
No.

- **Commodity prices**: natural gas and energy market prices
- **Policy & regulation**: tax credits, clean energy requirements, and other policy-driven resource constraints and alternatives
- **Technology costs**: changes in the costs of CCGTs, CCS, the Fermi 2 EPU, and energy storage technologies
- **Resource alternatives**: alternative generation, storage, and replacement-resource options, including advanced nuclear, biomass, long-duration energy storage, hydrogen-fueled generation, and alternative approaches to replacing the Monroe Power Plant
- **Resource availability**: renewable siting constraints and storage build constraints
- **Asset lifecycle:** various asset retirement dates and replacement resources
- **Market reliance**: the availability of energy and capacity purchases

Together, these analyses test how materially different assumptions and future conditions could affect resource needs, portfolio costs, and resource selections, and help assess whether key portfolio decisions remain reasonable across a range of possible outcomes.

Witness Manning explains how these scenarios and sensitivities were incorporated into the modeling and used to inform selection of the PCA.

Q154. Did the Company use any tools to compare results of the various sensitivities?

A154. Yes. As further described by Witness Manning, the Company used a portfolio metric evaluation process to compare portfolio results across the metrics identified

Line No.

in Table 6. The process ranked each sensitivity by category and then applied a weighted scoring approach to develop an overall comparison score. This allowed the Company to compare sensitivities consistently and identify which options performed better or worse across cost, environmental, reliability, market risk, flexibility, and resource diversity considerations.

Table 6 Portfolio Evaluation Metrics

Metrics	Description
Cost Differentials	Compares the overall cost performance of each sensitivity
Environmental	Compares emissions reduction and environmental performance
Reliability and Capacity Adequacy	Assesses how well each sensitivity supports system reliability and measures the risk of not meeting customer demand
Market Exposure & Risk	Compares the level of reliance on market purchases
Flexibility & Integration	Evaluates renewable curtailment and overall system flexibility
Resource Diversity	Measures the diversity of the resource mix
Weighted Score	Combines the parameters into one overall comparison result

Further details regarding the portfolio metric evaluation process are provided in Witness Manning's testimony.

Q155. How did the PCA perform when tested under the required scenarios and sensitivities?

A155. The PCA was tested under all required scenarios and sensitivities to evaluate its performance under a range of potential future conditions. The analysis supported the Company's conclusion that the PCA is the most reasonable and prudent plan

Line
No.

under the range of assumptions evaluated and remained reliable, with a diverse resource mix capable of meeting customer demand across changing conditions. As expected in sensitivities and scenarios that assumed higher load growth and the addition of large loads, the model selected additional resources to meet the increased demand. Witness Manning provides detailed modeling results.

Large Load

Q156. Which identified large load customers are reflected in the base load forecast submitted with this IRP?

A156. The base load forecast includes the load associated with both OACS and Google based on the information and assumptions incorporated into the forecast when it was finalized. The customers were treated as contracted large loads in the filed forecast. The base forecast reflects approximately 1.4 GW of maximum load associated with OACS and 1.0 GW associated with Google. Therefore, the base load forecast incorporates the projected energy and peak-demand impacts of these customers. Witness Sirwaitis describes the development of the load forecast in more detail, including the treatment of OACS and Google.

Q157. How did the Company treat other prospective large load customers in the IRP analysis?

A157. The base load forecast submitted with this IRP does not include the load associated with other prospective large load customers that were not reflected as contracted loads in the forecast when it was finalized. Instead, the Company evaluated prospective large load growth through the low, medium, and high large load growth sensitivities discussed below in my testimony and by Witness Manning. Those

Line No.

sensitivities allow the Company to assess how different levels of prospective large load growth could affect resource needs and portfolio outcomes without assuming that each prospective customer is contracted or will ultimately take service. Witness Sirwaitis provides additional information on the base load forecast assumptions.

Q158. Were the resources and other planning assumptions associated with the contracted OACS and Google loads reflected in the 2026 IRP modeling starting point?

A158. Yes. The Company reflected the following resources, contractual arrangements, and other planning assumptions associated with the contracted OACS and Google loads in the IRP modeling starting point:

- OACS
  - 1,383 MW of 4-hour lithium-ion batteries assumed to be in service by 2029; and
  - 1,803 MW of renewables included as a planning assumption associated with the OACS load.
- Google
  - 400 MW of 4-hour lithium-ion batteries and 50 MW of 8-hour lithium-ion batteries assumed to be in service by 2029;
  - 300 MW Zonal Resource Credit (ZRC) contract through May 2033;
  - Short-term DR agreement through May 2033; and
  - 1,600 MW of renewable resources associated with the Google VGP special contract.

Line
No.

Witness Manning describes the IRP modeling starting point and the treatment of these resources, contractual arrangements, and other planning assumptions in the Company's modeling.

Q159. Are there requirements related to large loads in the MPSC's IRP filing requirements?

A159. Yes. The requirements related to large loads were included in the IRP filing requirements adopted by the Commission's December 18, 2025, order in Case Nos. U-21867 and U-21570. Specifically, the IRP filing requirements direct utilities to develop, "a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model" (p. 21). It also states that "utilities must show the relationship between this forecast and what the utility has publicly disclosed about load growth from prospective large load customers" (p. 18).

Q160. How did the Company develop the low, medium, and high large load sensitivity forecasts?

A160. The Company developed the low, medium, and high large load forecasts by evaluating a range of prospective large load growth based on information available when the forecasts were finalized. Consistent with the MIRPP and IRP filing requirements, the Company applied a probabilistic methodology to known interested large load opportunities to develop aggregate forecast levels representing

Line
No.

a reasonable range of potential outcomes. Witness Sirwaitis describes the development of the low, medium, and high large load forecasts in greater detail.

Q161. How do the Company's low, medium, and high large load sensitivity forecasts compare with the Company's publicly disclosed information regarding prospective large load growth?

A161. The low and medium large load sensitivity forecasts are generally consistent with the range of prospective large load opportunities publicly disclosed by the Company when the forecasts were developed. The high sensitivity forecast evaluates a greater level of prospective large load growth and should be viewed as an upper-bound planning sensitivity that does not correspond directly to the publicly disclosed opportunities. In the 2025 year-end earnings call in February 2026, the Company reported 3 GW of data center load in late-stage negotiations (which included the subsequently announced Google agreements) and other opportunities for an additional 3-4 GW of new load.[43] In the 2026 Q1 earnings call in April 2026, the Company announced the execution of the Google agreements while reporting advanced discussions for 2 GW of additional data center load and other opportunities for an additional 3-4 GW of new load.[44]

[43] DTE Energy, Q4 2025 Earnings Conference Call Presentation. February 17, 2026. https://s24.q4cdn.com/970999156/files/doc_financials/2025/q4/Q4-25-presentation-FINAL.pdf. Accessed August 24, 2026.
[44] DTE Energy, Q1 2026 Earnings Conference Call Presentation. April 30, 2026. https://s24.q4cdn.com/970999156/files/doc_financials/2026/q1/Q1-26-presentation-FINAL.pdf. Accessed August 24, 2026.

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Q162. Can you summarize the results of the low, medium, and high large load sensitivity forecasts relative to the resource portfolio reflected in DTE Electric's 2026 IRP PCA?

A162. Yes. The low, medium, and high large load sensitivity forecasts evaluate prospective large load growth outcomes beyond the contracted customer load included in the PCA. For each sensitivity forecast, the Company modeled the resource portfolio that would be needed to serve the assumed additional load and compared that portfolio with the resources reflected in the PCA. Across these low, medium, and high large load growth sensitivity forecasts, the model identified portfolios capable of serving the assumed levels of additional customer demand while satisfying the applicable policy and capacity requirements reflected in the modeling. Witness Manning provides additional detail in her testimony.

Customer Choice Assumptions

Q163. Can you summarize how Customer Choice participation was reflected in the 2026 IRP base load forecast?

A163. Michigan law permits Customer Choice participation up to 10% of the Company's retail sales. Because projected retail sales increase over the planning period, the amount of load eligible to participate in Customer Choice also increases. For purposes of the 2026 IRP, the Company assumed that Customer Choice would remain fully subscribed to the 10% cap throughout the planning period. Witness Sirwaitis provides additional detail regarding the treatment of Customer Choice in the Company's load forecast.

Line
No.

Q164. How does projected retail sales growth affect the Customer Choice assumption in the base load forecast?

A164. Because the Customer Choice cap is based on a percentage of retail sales, projected increases in service area sales result in a corresponding increase in the amount of load eligible to participate in Customer Choice. As a result, additional DTE Electric customers may elect to enroll in Customer Choice up to the increased cap. As described by Witness Sirwaitis, once the OACS and Google loads are fully ramped, total Choice program sales are projected to increase from approximately 4,500 GWh in 2025 to approximately 6,800 GWh in 2046.

Q165. Are there specific resource planning considerations relative to Customer Choice program participation?

A165. Yes. The Company's Customer Choice program is currently fully subscribed and there is a queue for customers. The Company assumes that Customer Choice will remain fully subscribed to the 10% cap, but actual participation may vary over time. Customers currently taking bundled service may not elect Customer Choice service as additional space becomes available under the cap, and existing Customer Choice customers may return to bundled service.

Q166. How did the Company study this Customer Choice enrollment uncertainty in the IRP?

A166. The Company evaluated this uncertainty through an Alternative Customer Choice sensitivity. As described by Witness Sirwaitis, the sensitivity assumes that Customer Choice participation does not continue to increase with projected retail sales but instead remains at the forecasted 2028 level throughout the remainder of

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No.

the planning period. Witness Manning discusses the resulting effects on resource needs and portfolio selection. The Company also evaluated broader uncertainty in future customer demand through its stochastic and resource adequacy analyses, as discussed by Witnesses Busse and Manning.

Capacity and Resource Planning Requirements

Q167. What capacity planning requirement does the Company plan for?

A167. The Company plans to meet the MISO PRMR for each season over the modeled timeframe based on the MISO DLOL construct. This information is shown in Witness Manning's Exhibits A-2.1 and A-2.2 and is based on MISO published forecasts. The PRMRs will vary over time, as will the accreditation of resources as further described in the testimony of Witness Burgdorf. Witness Manning describes the Company's capacity planning process in more detail.

Q168. What is the resource adequacy threshold the Company is planning for?

A168. The resource adequacy threshold the Company is planning for is to meet the federal reliability standard of a loss of load expectation (LOLE) of 0.1 or one day in 10 years. The specific resource adequacy reliability requirements are further discussed by Witnesses Burgdorf and Manning.

Q169. What sensitivities did the Company conduct specifically to support the CON requests, and what did the results of those sensitivities demonstrate?

A169. The Company conducted four sensitivities to support the CON requests, as set forth in Table 7 below. Witness Manning details these sensitivities and the results.

Line
No.

1 **Table 7 Sensitivities Supporting the CON Requests**

Sensitivity	Description	Summary Results
NO_BUILD	Evaluates a constrained-build boundary case that materially limits incremental resource additions relative to the Base Case	This case failed multiple reliability evaluations, demonstrating high levels of unserved energy, an inability to satisfy the Company's PRMR, and overall resource inadequacy
NON_DISPATCH	Evaluates a case in which new dispatchable resources are not available for selection, allowing the model to optimize using other eligible resource options. This sensitivity was included among the Monroe Power Plant Units 1 and 2 replacement resource sensitivities required by the Settlement Agreement in Case No. U-21193.	While this sensitivity meets the PRMR, the Company observes unserved energy and does not satisfy resource adequacy requirements
SMR_34	Evaluates a case in which a SMR is forced into the portfolio in 2034, allowing the Company to assess the impact of adding an SMR resource at that point in time	Due to the gap between the Monroe Power Plant Unit 1 & 2 retirements and the inclusion of the SMR, unserved energy is observed in 2033. This sensitivity is also more costly than alternatives including the PCA
LDES_2032	Evaluates a case in which LDES is forced into the portfolio in 2032 when Monroe Power Plant Units 1 and 2 retire. While LDES was selected in later years in other cases, this sensitivity specifically	This sensitivity still selected 1,400 MW of CCGT with CCS in addition to the LDES, resulting in a higher cost plan

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No.

Sensitivity	Description	Summary Results
	tests the impact of an earlier LDES deployment	

Q170. What were the results of the resource adequacy modeling under a "no build" sensitivity?

A170. As discussed further by Witnesses Manning and Brooks, the Company conducted resource adequacy modeling to understand the capacity needs under a "no-build" sensitivity. The "no-build" sensitivity failed to meet the 0.1 LOLE resource adequacy requirements in 2033. It resulted in a LOLE of 1.12.

Selection of the PCA

Q171. Does the PCA, as presented in Part I, represent the most reasonable and prudent means of meeting DTE Electric customers' energy and capacity needs?

A171. Yes. As summarized in Table 8 below and Exhibit A-1.4, the PCA appropriately meets the criteria identified in MCL 460.6t(8). Based on that record, the PCA represents the most reasonable and prudent means of meeting DTE Electric customers' energy and capacity needs.

Table 8 Reasonable and Prudent PCA

	MCL Statutory Reference & Requirement	PCA Summary (Witness)
1	**460.6t(8)(a)(i)** – Resource adequacy and capacity to serve anticipated peak electric load, applicable	• Meets applicable MISO PRMR (Manning, Burgdorf) • Meets Company's forecasted share of the MISO LRZ 7 summer local clearing

Line No.	MCL Statutory Reference & Requirement	PCA Summary (Witness)
	planning reserve margin, and local clearing requirement	requirement during each of the first five planning years (Burgdorf) • Meets 0.1 LOLE resource adequacy threshold in the modeled 2029 and 2033 study years (Manning, Brooks)
2	**460.6t(8)(a)(ii) –** Compliance with applicable state and federal environmental regulations	• The PCA reflects applicable environmental compliance requirements and includes the investments and compliance pathways necessary for the existing fleet and proposed resource plan to comply with applicable state and federal environmental requirements (Marietta, Manning)
3	**460.6t(8)(a)(iii)** – Competitive pricing	• For requests for relief included in this filing, DTE Electric conducted a competitive solicitation in compliance with the Filing Requirements (Pratt) • The 2025 All-Source RFP provided market-based pricing and evaluated Company-owned and third party resource proposals (Pratt) • Independent Monitor concluded the 2025 All-Source RFP was conducted in accordance with the MPSC Competitive Procurement Guidelines (Pratt)
4	**460.6t(8)(a)(iv)** – Reliability	• There is no unserved energy observed in PCA portfolio analysis (Manning) • ITC evaluated transmission reliability impacts and necessary system upgrades associated with the PCA, and the resulting transmission considerations were incorporated into the IRP analysis (Djordjevic, Manning)
5	**460.6t(8)(a)(v) –** Commodity price risks	• Modeled scenarios and sensitivities for varying natural gas and market prices; under the higher-cost sensitivities, NPVRR increased while the resulting resource portfolios remained mostly unchanged; conducted stochastic economic analysis, which showed that

Line No.	MCL Statutory Reference & Requirement	PCA Summary (Witness)
		the PCA performed well across varied market, fuel price, and operating assumptions and supports the conclusion that the portfolio manages risk (Manning, Busse)
6	**460.6t(8)(a)(vi) –** Diversity of generation supply	• Portfolio metric evaluation included an assessment of resource diversity; Final PCA is diverse and maintains a balanced mix of renewables, energy storage, nuclear, natural gas, and demand-side resources (Manning)
7	**460.6t(8)(a)(vii) –** Whether the proposed levels of peak load reduction and EWR are reasonable and cost effective	• Incorporates EWR savings levels that the Company determined are achievable based on available energy savings potential and program deliverability (Kupser) • Additional EWR savings levels evaluated through IRP modeling and sensitivity analyses; the 2.17% and 2.5% savings levels were determined not feasible (Manning, Kupser) • DR portfolio includes 638 MW of ICAP in summer 2029 and provides accredited capacity and peak demand reduction (Leuker)
8	**460.6t(8)(a)(viii) –** Affordability	• Evaluated PCA rate impacts by customer class and residential affordability impacts through energy burden analysis by income level; the rate analysis shows lower average rates over the study period for all customer classes compared with the 2022 PCA (Machi)
9	**460.6t(8)(a)(ix) –** Overall cost-effectiveness in providing utility service	• Compared portfolio costs and Net Present Value Revenue Requirement across scenarios and sensitivities to evaluate the relative cost-effectiveness of resource portfolios; under current assumptions, the 2026 PCA is approximately $3.5 billion lower in NPVRR than the 2022 PCA (Manning) • Evaluated the least-cost portfolios, which did not satisfy resource adequacy

Line No.	MCL Statutory Reference & Requirement	PCA Summary (Witness)
		requirements, in selecting a PCA that balances cost with reliability and other planning criteria (Hajj, Manning) • Evaluated stochastic financial risk and variability in portfolio costs under uncertain market, fuel price, and operating conditions; the analysis showed that the PCA performed well across the varied assumptions evaluated and manages risk (Busse, Manning) • Customer rate analysis shows lower average rates over the study period for all customer classes compared with the 2022 PCA (Machi)
10	**460.6t(8)(b) –** To the extent practicable, use of a Michigan-resident workforce for construction or investment in capacity resources in this state, subject to the statutory border-county exception	• The Solar PPA is a Michigan-based solar PPA that will be developed with at least 95% of the construction workforce comprised of Michigan residents(Pratt) • Acquisition of Michigan Power Cogeneration preserves continued operation of an existing capacity resource and its workforce in Ludington (Pratt) • Contracting for the Livingston County and Monroe County projects requires use of a Michigan workforce to the extent practicable, and the Company estimates more than 90% of craft labor will be comprised of Michigan residents (Banks)
11	**460.6t(8)(c) –** Applicable apprenticeship, prevailing-wage, and project-labor/collective-bargaining labor standards for new or rehabilitated capacity resources	• Company plans to comply with applicable labor standards under MCL 460.6t(8)(c) for construction of the proposed Livingston County and Monroe County projects (Banks) and the Solar PPA (Pratt)
12	**460.6t(8)(d) –** The plan is consistent with the renewable energy plan requirements and goals of section 28 of…2008 PA 295, MCL 460.1028, the clean energy requirements of section 51 of… 2008 PA	• Complies with the IRP, CEP, and other applicable requirements; See exhibit A-1, A-1.1, and A-1.3 (Hajj) • CEP demonstrates a pathway for the PCA to satisfy Michigan's Clean Energy Standard, including at least 80% clean

Line
No.

	MCL Statutory Reference & Requirement	PCA Summary (Witness)
	295, MCL 460.1051, the energy waste reduction measures in section 77 of… 2008 PA 295, MCL 460.1077, and the energy storage target of section 101 of… 2008 PA 295, MCL 460.1101	energy beginning in 2035 and 100% beginning in 2040 (Hajj, Manning) • PCA incorporates EWR levels consistent with applicable statutory requirements and evaluates additional EWR savings through IRP modeling (Kupser, Manning) • PCA includes the renewable resources necessary to support compliance with the 50% RPS beginning in 2030 and 60% beginning in 2035 (Bilyeu, Manning) • Existing, approved, and planned energy storage resources support compliance with and are expected to exceed DTE Electric's proportional share of the statewide energy storage target (Schroeder, Hajj)
13	**460.6t(8)(e) –** The plan promotes environmental quality and public health and reasonably mitigates adverse effects on human health due to power generation, with a priority on mitigating impacts and prioritizing benefits to communities disproportionately impacted by pollution and other environmental harms	• Retires Monroe Power Plant and Superior Peaking Station, which are located in or near EJ Communities identified through MIEJScreen (Marietta) • PCA reduces emissions, water intake and discharge, and waste generation and disposal (Marietta) • EPA COBRA health-impact assessment indicates an overall public-health benefit associated with the PCA (Marietta)
14	**460.6t(8)(f) –** The plan meets the requirements of subsection (5)	• PCA meets the requirements of MCL 460.6t(5); see Exhibit A-1 of my testimony

Q172. Did the Company consider selecting the least-cost plan for the IRP PCA?

A172. Yes. As described by Witness Manning, the least-cost plans across the three scenarios were evaluated through the portfolio metric evaluation process and resource adequacy. All three least-cost plans were observed to have unserved

Line
No.

energy and failed to meet resource adequacy requirements. The PCA reflects a portfolio that meets resource adequacy requirements so the Company can serve customers reliably.

Q173. What is the Company's current capacity position as reflected in this IRP filing?

A173. The Company has included an updated view of its current capacity position in this filing, as supported by Witness Manning and reflected in Exhibit A-2.1. As reflected in Exhibit A-2.1, the Company does not have a material long-term need for generation capacity during the five-year planning horizon (2027-2031).

Q174. Does the Company still believe a five-year planning horizon, as established by the September 26, 2019 order in Case No. U-18091, is the most appropriate time frame for evaluating capacity needs relative to PURPA?

A174. Yes. A five-year outlook remains the most appropriate timeframe for determining a capacity need under PURPA. A longer planning horizon is not needed to show a long-term need. A five-year outlook is consistent with several relevant regulatory cycles: (1) the IRP cycle in Michigan per State law; (2) the required five-year Power Supply Cost Recovery plan forecast, which is filed annually; and (3) the State requirement in PA 341 section 6v (1) relative to the Commission conducting contested proceedings for reviewing PURPA avoided costs.

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PART VI: REQUESTS FOR COMMISSION APPROVAL

Q175. What is the statutory basis for the Company's cost pre-approval requests for investments and resources planned to commence within three years after approval of the IRP?

A175. MCL 460.6t(11) requires the Commission, when approving an IRP, to specify the costs approved for the construction of or significant investment in an electric generation or energy storage facility, the purchase of an existing electric generation or energy storage facility, the purchase of power under a power purchase or energy storage agreement, and other investments or resources used to meet energy and capacity needs that are included in the IRP. Under MCL 460.6t(11), the approved costs for specifically identified investments or resources included in an approved IRP and commenced within three years after the Commission's order approving the IRP are considered reasonable and prudent for cost recovery purposes.

The Company therefore requests that the Commission approve the PCA including the specifically identified resources discussed below and specify the costs approved for those resources under MCL 460.6t(11).

Q176. What investments and resources are the subject of the Company's cost pre-approval requests that are planned to commence within three years after approval of the IRP (2028-2030)?

A176. The Company is seeking Commission approval of the costs associated with the investments and resources identified in Table 9. These include the planned 2028 through 2030 investments in the existing CoolCurrents DR resource, the Solar PPA, and the acquisition of the Michigan Power Cogeneration project. Witness Leuker

Line No.

supports the CoolCurrents planned investments and associated capital costs, and Witness Pratt supports the other identified resources and costs.

Table 9 Resources Subject to Requested Section 6t(11) Cost Approval

Resource Type	Resource or Project	Owner / Counterparty	Contract Type	MW	Statutory Approval
DR	CoolCurrents	DTE Electric	N/A	30	Other investments or resources used to meet the Company's energy and capacity needs
Solar	[redacted]	[redacted]	PPA	125	Purchase of power under a PPA
Natural Gas Cogeneration	Michigan Power Cogeneration	DTE Sustainable Generation	PSA	138	Purchase of an existing electric generation facility

Each resource is identified in the PCA and is planned to commence within three years after Commission approval of the IRP.

Q177. What costs is the Company requesting the Commission to pre-approve for the resources identified in Table 9?

A177. DTE Electric is requesting that the Commission specify and approve the following costs under MCL 460.6t(11) for the resources identified in Table 9 and further detailed in Exhibit A-1.7:

1. $21.3 million in projected capital costs for the planned CoolCurrents DR program from 2028 through 2030. Witness Leuker describes the planned investments, explains their relationship to the CoolCurrents capacity reflected in the PCA, and supports the associated capital costs and cost pre-approval request;

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2. $130 million in projected capital costs to purchase the Michigan Power Cogeneration project. Witness Pratt describes the facility, the proposed acquisition, and the associated cost pre-approval request; and
3. The [redacted] price under the proposed 20-year Solar PPA with [redacted] for the [redacted]. The Company also requests that the Commission authorize the financial incentive provided by MCL 460.6t(15) for the PPA. Consistent with MCL 460.6t(15), the financial incentive will be calculated annually based on the contract payments made in that year and the Company's applicable pretax weighted average cost of permanent capital established in the Commission's final order in the Company's most recent general rate case, as updated by each succeeding general rate case over the term of the PPA. Witness Pratt describes the proposed PPA and supports the associated cost pre-approval request.

Q178. What Certificate of Necessity approvals is the Company requesting for the proposed Livingston County project and Monroe County project?

A178. DTE Electric requests three Certificates of Necessity for each proposed project under MCL 460.6s, for a total of six CONs. For each project, the Company requests that the Commission issue:

1. **Need for Power:** a certificate under MCL 460.6s(3)(a) determining that the power to be supplied as a result of the proposed construction is needed;

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2. **Resource Selection:** a certificate under MCL 460.6s(3)(b) determining that the project's size, fuel type, and other design characteristics represent the most reasonable and prudent means of meeting that power need; and
3. **Costs and Financing:** a certificate under MCL 460.6s(3)(d) determining that the project's estimated capital costs and financing plan will be recoverable in customer rates, subject to MCL 460.6s(4)(c).

For the certificates requested under MCL 460.6s(3)(d), the Company requests approval of an estimated capital cost of approximately $3.925 billion for the Livingston County project and approximately $2.518 billion for the Monroe County project.

Q179. Which witnesses provide the principal support for the requested CONs?

A179. DTE Electric's requested CONs are supported by several Company witnesses whose testimony addresses complementary subjects:

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Table 10 CON Witness Overview

	Witness	Support for the Requested CONs
1	Manning	Presents the resource planning, portfolio modeling, and resource adequacy analyses supporting the identified need for additional firm, dispatchable generation and the inclusion of the proposed projects in the PCA
2	Pratt	Describes the 2025 All-Source RFP, the evaluation and selection of the proposed projects, the resource alternatives considered, the six requested CONs, and the basis for concluding that the proposed projects represent the most reasonable and prudent means of meeting the identified power need
3	Busse	Supports the resource cost, operating, and other financial assumptions used in the IRP modeling and presents the stochastic economic risk analysis
4	Stansell	Presents the projects' sites, technologies, configurations, operating characteristics, CCS-ready designs, capital cost estimates, and O&M assumptions
5	Banks	Addresses the projects' contracting and execution strategy, major equipment procurement, project controls, schedules, workforce, permitting coordination, and execution risks
6	Lind	Compares the engineering, procurement, and construction portions of the project estimates with costs for other recent utility-sponsored combined cycle projects and addresses whether the estimates fall within a zone of reasonableness
7	Uzenski	Supports the projects' proposed financing plan

Other Company witnesses provide additional evidence concerning transmission, fuel supply, environmental requirements and impacts, customer rate effects, and other subjects relevant to the Commission's review of the requested CONs.

Q180. Can you summarize the Company's requests for Commission action in this proceeding?

A180. Yes. The Company is seeking the following action from the Commission:

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- Determination that the Company complied with the statutory requirements, modeling parameters, filing requirements, and other orders and guidance applicable to the IRP, CEP, and CON;
- Approval of the IRP and determination that the PCA is the most reasonable and prudent means of meeting the Company's energy and capacity needs;
- Determination that the PCA satisfies compliance with the CES requirements;
- Determination that the PCA is consistent with the RPS which is demonstrated through the concurrently filed Amended REP;
- Determination that the PCA supports and meets the Company's portion of the statewide energy storage target;
- Determination that the Company complied with the competitive procurement guidelines;
- Determination that the Company does not have a capacity need in the next five years pursuant to PURPA;
- Pre-approval of capital costs related to the DR CoolCurrents program ($21.3 million) that commences within three years of the Commission's approval of this application;
- Pre-approval related to the Solar PPA, FCM, and associated annual costs that commence in 2030;
- Pre-approval of capital costs related to the Michigan Power Cogeneration project ($130 million) that commence in 2030;
- Approval of three Certificates of Necessity for the Livingston County CCGT project, including the certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed, the

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certificate that the size, fuel type, and other design characteristics of the proposed electric generation facility represent the most reasonable and prudent means of meeting that power need, and the certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c); and

- Approval of three Certificates of Necessity for the Monroe County CCGT project, including the certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed, the certificate that the size, fuel type, and other design characteristics of the proposed electric generation facility represent the most reasonable and prudent means of meeting that power need, and the certificate that the estimated purchase or capital costs of, and the financing plan for, the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers subject to MCL 460.6s(4)(c).

Q181. Has the Company evaluated opportunities to obtain federal financing support for proposed generation investments?

A181. Yes. The Company has evaluated and is actively pursuing opportunities to secure federal financing support for proposed generation and infrastructure investments,

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including funding available through the U.S. DOE's Energy Dominance Financing Program (EDF Program, formerly the Section 1706 loan program), authorized by Title XVII of the Energy Policy Act. The EDF program supports projects that retool, repower, repurpose, or replace existing energy infrastructure and provides access to long-term, federally backed financing at favorable borrowing rates.

Q182. What is the status of the Company's efforts to secure EDF program funding?

A182. In January 2025, the Company reached a conditional commitment with the DOE for up to $7.2 billion in EDF program funding to support infrastructure investments.[45] In December 2025, the Company's conditional commitment was extended through January 2027. As of the date of this filing, the Company and DOE have not executed a final loan agreement. However, the Company and DOE remain in close communication, and DTE Electric is actively pursuing the conditions outlined in the conditional commitment to reach the final loan agreement.

Q183. Does the Company intend to continue pursuing federal financing opportunities applicable to the proposed resource investments?

A183. Yes. The Company intends to continue pursuing federal financing opportunities that may be available and applicable to the proposed resource investments reflected in its 2026 IRP. This includes continued engagement with the DOE's Office of Energy Dominance Financing regarding EDF program funding. The Company

[45] U.S. Department of Energy, Loan Programs Office, "LPO Announces Conditional Commitments to DTE Gas and DTE Electric to Fund Infrastructure Improvements while Maintaining Affordability for Customers." January 15, 2025. https://www.energy.gov/edf/articles/lpo-announces-conditional-commitments-dte-gas-and-dte-electric-fund-infrastructure. Accessed August 24, 2026.

Line No.

continues discussions with the DOE regarding the eligibility of projects for the Energy Dominance Financing Program. Biannually, the Company files an update with the MPSC on its grant and other federal funding activities in Case No. U-21227.

Q184. Would the financing opportunities affect the plan or approvals requested in this proceeding?

A184. No. The availability of federal financing assistance would not affect the resource plan, the proposed investments, or the approvals requested in this proceeding. The Company's request for approval is based on the need for the proposed resources and the reasonableness of the associated investments independent of any particular financing source. However, if the Company ultimately obtains EDF program funding, customers could benefit through reduced financing costs relative to conventional financing alternatives. Such financing would affect how eligible investments are financed, but would not affect the underlying project scope, cost estimates, or need for the proposed resources.

PART VII: IMPLEMENTATION OF THE PCA

Q185. Can you describe the Company's implementation plan of the PCA?

A185. Yes. The Company has developed an implementation plan that identifies the major tasks, schedules, and milestones necessary to implement the PCA, with a focus on the first five years of the PCA (2027-2031). The implementation plan also identifies significant milestones expected in 2032, the first year of the second five-year period. The implementation plan addresses the sequencing of resource additions, program investments, regulatory filings, and planned generation retirements

Line No.

necessary to implement the PCA, maintain reliability and resource adequacy, and support compliance with applicable renewable and clean energy requirements. Key activities and milestones during the first five-year period (2027-2031) include the following:

- Retiring the Monroe Power Plant Units 3 & 4 in 2028, consistent with the Commission-approved Settlement Agreement in Case No. U-21193;
- Building new renewables identified in the PCA, as further discussed by Witness Bilyeu;
- Purchasing power from the Solar PPA project starting in 2030, as described by Witness Pratt;
- Purchasing the Michigan Power Cogeneration facility in 2030, as described by Witness Pratt;
- Developing and constructing the Livingston County project, which has a planned COD in 2031, as described by Witnesses Pratt, Stansell, and Banks;
- Developing and constructing the Monroe County project, which has a COD in 2032, as described by Witnesses Pratt, Stansell, and Banks;
- Implementing the planned 2028-2030 CoolCurrents investments and continuing enrollment and other planned activities for Smart Savers, as described by Witness Leuker;
- Implementing the CVR/VVO program, as described by Witness Singh;
- Pursuing federal support to fund the initial Fermi 2 EPU scoping studies and, if the PCA is approved and the scoping study confirms project feasibility, seeking cost approvals for the EPU in subsequent filings as the project progresses, as discussed by Witness Pratt; and

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- Executing on and complying with key regulatory case proceedings needed to implement the 2026 IRP PCA before filing the next IRP.

Significant milestones expected in 2032, the first year of the second five-year period include:

- Retiring Monroe Power Plant Units 1 and 2, consistent with the Commission-approved Settlement Agreement in Case No. U-21193;
- Retiring the Superior Peaker Station, as described by Witness Pratt; and
- Achieving the planned COD for the Monroe County project, as described by Witnesses Pratt, Stansell, and Banks.

Overall, the Company is effectively positioned to implement the investments and milestones identified for the first five-year period and the significant milestones expected in 2032. Implementation will require the Company to secure the workforce, resources, materials, and contracts needed for the applicable projects and programs. A high-level implementation plan can be found in Exhibit A-1.8, PCA Implementation Schedule: First Five-Year Period and Significant 2032 Milestones.

Q186. Can you describe the Company's schedule and key actions for implementing ongoing and planned demand-side programs during the first five-year PCA period (2027-2031)?

A186. Yes. During 2027-2031, the Company will continue to operate and implement its existing programs and will incorporate the new or expanded programs once approved in this filing or other case proceedings. Specifically, the Company will

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continue to strive for enrollment growth in existing programs and enhance customer outreach and marketing as well as evaluating program performance.

For DR programs, the Company will purchase new CoolCurrents load control devices and replace obsolete or unavailable devices through the planned 2028 through 2030 investments and will continue enrolling new customers in the Smart Savers program as described by Witness Leuker. The CoolCurrents investments are necessary to maintain and achieve the program's forecasted capacity contribution within the aggregate DR portfolio reflected in the PCA. The Company will also evaluate program performance and recommend changes in future rate case proceedings, if necessary, and explore new pilot opportunities and seek Commission approval as needed. Beginning in 2028, the Company plans to develop and implement a battery VPP program. The implementation schedule may be updated to reflect changes in customer participation, market considerations, technological developments, and regulatory requirements while maintaining alignment with the PCA assumptions.

For EWR programs, the Company will continue operating its existing portfolio through the approval of this case proceeding and will incorporate any changes from the approved PCA. Following Commission approval, the Company plans to file its next EWR plan for the 2029-2032 period within eight months of receiving a final order in this case. The plan will be aligned with the PCA approved in this case and will describe the programs, investments, and actions the Company plans to take to achieve future EWR savings targets. The Company will also continue to file annual EWR reconciliation filings to report, verify, and reconcile program performance

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and savings achieved in the year prior. Additional information regarding the implementation of the EWR targets reflected in the PCA is provided in Witness Kupser's testimony.

Q187. Can you describe the Company's principal actions for implementing the supply-side resources and retirements reflected in the PCA during the first five-year period (2027-2031) and the significant milestones expected in 2032?

A187. Yes. The Company's current implementation schedule is summarized in Exhibit A-1.8, PCA Implementation Schedule. During the first five-year period, 2027 through 2031, the Company's principal supply-side implementation activities include renewable resource procurement and development; execution and performance of the Solar PPA; acquisition of the Michigan Power Cogeneration facility; development, permitting, construction, and commissioning activities for the proposed Livingston County and Monroe County projects; development activities for the Fermi EPU; and retirement of the Monroe Power Plant Units 3 and 4. The implementation plan also identifies the planned retirement of the Monroe Power Plant Units 1 and 2 and the Superior Peaking Station, together with the planned COD milestone for the Monroe County project, in 2032, the first year of the second five-year period.

Q188. Will the programs and resource additions contained in the PCA strive to use a Michigan workforce, to the extent practical, as outlined in MCL 460.6t(8)(b) and MCL 460.6s(4)(e)?

A188. Yes. Consistent with the Company's past practices and commitment to support Michigan-based suppliers, the Company will strive to utilize Michigan workers as

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the plan is implemented. In DTE Electric's RFPs and during contracting, the Company has traditionally indicated a preference for suppliers and projects that have Michigan headquarters and that utilize Michigan workers. The Company will continue to do so in future opportunities. Witness Pratt further describes how the Solar PPA project and MI Power Cogeneration facility will continue to support the Michigan workforce. Witness Banks describes how the CCS-ready CCGT projects support Michigan based businesses and workforce.

Q189. Can you describe how the Company plans to implement the PCA during the first five-year period and thereafter to support compliance with the CES and RPS goals established by 2023 PA 235?

A189. The PCA meets the 50% RPS requirement beginning in 2030 and includes additional renewable and clean energy resource additions that continue the Company's progress to the 60% RPS requirement and 80% CES requirement beginning in 2035, and the 100% CES requirement beginning in 2040. To implement this resource plan, the Company's implementation plan includes developing renewable resources with planned commercial operation dates in 2031 and 2032 to meet the requirements as defined in Part II of my testimony. The Company anticipates procuring these resources through future annual competitive solicitations at least three years in advance of the identified COD. Following the competitive solicitation, the Company will work with the selected bidder to develop the project. The Company will continue this renewable resource development and procurement process beyond the first five-year period to support the additional renewable additions reflected in the PCA and continued compliance with the RPS and CES requirements.

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The PCA includes the proposed Livingston County and Monroe County projects, which are designed to be CCS-ready to allow for the future integration of CCS. During the first five-year period, the Company plans to undertake the development, permitting, engineering, procurement, and construction activities for the proposed CCGT facilities necessary to achieve the applicable commercial operation milestones. The PCA reflects the planned future implementation of CCS beginning in 2035 to support compliance with the CES. The Company is not requesting approval in this proceeding of the future CCS systems, CCS implementation costs, or a detailed CCS execution plan. Any future CCS implementation will remain subject to applicable approvals.

The PCA also includes the acquisition of the Michigan Power Cogeneration facility in 2030. The Michigan Power Cogeneration facility is part of an integrated portfolio of generation resources and other actions reflected in the PCA and CEP. That portfolio meets the applicable CES requirements and results in substantial greenhouse gas reductions, as presented by Witness Marietta. The Michigan Power Cogeneration facility possesses the facility characteristics identified in MCL 460.1003(i)(iii), as described by Witness Pratt. The "plan" referenced in that provision is properly considered as the Company's overall CEP. This is consistent with MCL 460.1003(i), which defines a clean energy system to include a "system or set of electricity generation systems," and with MCL 460.1003(i)(iii), which calls for Commission approval of a plan that achieves functional equivalence. Witness Pratt describes the proposed acquisition, the facility's characteristics and operating role, the applicable requirements of MCL 460.1003(i)(iii), and the requested cost preapproval.

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Q190. Can you discuss the role of competitive bidding in the implementation of the PCA?

A190. Yes. Competitive bidding will play an important role in implementing the PCA. The Company intends to issue annual competitive bidding solicitations to select new resources as set forth in the PCA. The Company will continue to use and abide by the competitive procurement guidelines as defined by the Commission in all future generation competitive procurement processes related to this IRP. In addition, the Company will ensure compliance with the requirements of MCL 460.6t(8) including applicable labor-related provisions and all other applicable requirements when conducting competitive solicitations. Following the competitive procurement process, the Company would bring forward specific projects or contracts to the Commission for approval as needed.

Q191. How does the plan mitigate implementation risks?

A191. The plan mitigates implementation risks by sequencing resource additions ahead of planned generation retirements, helping maintain reliability and resource adequacy throughout the transition. The plan also supports a diversified portfolio approach and leverages existing assets, like the Michigan Power Cogeneration facility, to reduce execution risks.

The plan prioritizes commercially available, proven technologies in the near-term, while allowing emerging technologies additional time to mature long-term, improving cost certainty and reducing technology risk. The proposed CON projects are designed to meet the clean energy system definition in 2035, begin providing

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No.

energy and capacity as early as 2031, and support the retirement of Monroe Power Plant Units 1 and 2 to complete the Company's exit of coal-fired generation. Implementation of CCS in 2035 supports the long-term compliance requirements while limiting near-term technology risks.

Witnesses Manning, Pratt, Bilyeu, Schroeder, Stansell, Swiech, and Djordjevic discuss several risks including economic, weather, fuel prices, supply chain, siting, and interconnection delays associated with the implementation of the PCA.

Q192. How will the Company report on the status of an approved plan pursuant to MCL 460.6t(14) and MCL 460.6s(7)?

A192. The Company plans to meet the requirements for reporting annually as defined in MCL 460.6t(14), which states "an electric utility shall annually, or more frequently if required by the commission, file reports to the commission regarding the status of any projects included in the initial 3-year period of an integrated resource plan approved…" and MCL 460.6s(7), which states "the utility shall annually file, or more frequent if required by the commission, reports to the commission regarding the status of any project for which a certificate of necessity has been granted under subsection (4), including an update concerning the cost and schedule of that project." Consistent with past practice, the Company will file annual status reports on the implementation of the PCA, including the investments and resources for which cost pre-approval is sought during the initial three-year period, projects approved through the certificates of necessity, and applicable CEP progress. The Company commits to filing the first annual report one year from the date of a

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Commission order approving this plan with subsequent reports filed annually thereafter.

PART VIII: CONCLUSION

Q193. Why should the IRP, CONs, and CEP be approved?

A193. In summary, DTE Electric's 2026 IRP is the most reasonable and prudent path to reliably and affordably serve customers while continuing the transition to a cleaner and more diverse generation portfolio. The PCA builds on the commitments established in the Company's 2022 IRP, reflects changes in state and federal energy policy, addresses evolving reliability needs, and incorporates a balanced and diverse mix of renewable energy, energy storage, nuclear generation, demand-side resources, and incremental firm dispatchable generation. Based on the analyses, modeling, stakeholder engagement, and supporting testimony presented in this proceeding, the Company requests that the Commission approve the 2026 IRP, including the CEP, the requested CONs, cost pre-approval requests, statewide energy storage target compliance, and all other relief requested in the application.

Q194. Does this complete your direct testimony?

A194. Yes. This completes my direct testimony.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAYLA D. MANNING

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAYLA D. MANNING

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Shayla D. Manning (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science in Business Administration from the University of Detroit Mercy in 2007. I received a Master of Business Administration and a Master of Financial Economics from University of Detroit Mercy in 2009 and 2012, respectively. I have also completed several Company-sponsored courses and attended various seminars to further my professional development.

Q4. What is your professional experience?

A4. After graduating from the University of Detroit Mercy, I began my professional career with DTE Energy in January 2008 as a Business Analyst in the Gas Sales and Marketing department. In that role, I was responsible for the gas consumption and revenue forecast for End User Transportation customers. In 2011, I transitioned to the Integrated Resource Planning group as an Energy Analyst. My responsibilities in this position included performing numerous analyses, modeling the generation asset portfolio of the Company using PROMOD® and other internal models to assess system cost impacts. Two years later, in 2013, I was promoted in the group to Principal Energy Analyst where my responsibilities increased. I led

various special project studies focused on the Company's power plants and I also gained additional model experience utilizing Strategist®. In 2014, I was promoted to Senior Strategist. As Senior Strategist, I was responsible for developing and maintaining a revenue requirement model to evaluate the cost impacts of various long-term plans, proposed plant projects, renewable resources, and demand side management programs. I also organized and managed the development of the Company's 2017 Integrated Resource Plan (IRP) Report. In 2018, I accepted a role as Supervisor within the Corporate Energy Forecasting group, focusing on Long-Term forecasting. In this role, I was responsible for the preparation of long-term sales forecasts (one year or greater) and the development of the electric sales forecasting activities for DTE Electric. These activities included data collection, statistical analysis of data, forecast model building, and interaction with other departments on forecast-related topics. In 2020, I accepted the position as Supervisor within the Integrated Resource Planning group and was promoted to Manager in 2021. In 2024, the IRP team merged with another team to form the Resource Planning and Transmission Modeling (RP&TM) team, which I currently manage.

Q5. What are your current duties and responsibilities?

A5. As the Manager of the RP&TM team, I am responsible for leading the modeling team that conducts capacity expansion and production cost modeling to support integrated resource planning, economic analyses, and long-term strategy. In addition to these responsibilities, I also oversee the team's transmission-related studies and engagements, which support reliability assessment and coordination with external transmission entities.

Line No.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in the following cases:

U-20373	2020-2021 DTE Electric EWR Plan
U-20527	2020 PSCR Plan
U-20373	Amended 2020-2021 DTE Electric EWR Plan
U-20826	2021 PSCR Plan
U-21193	2022 Integrated Resource Plan

Purpose of Testimony

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of my testimony is to describe the resource planning modeling process and support the modeling performed for the 2026 IRP. My testimony is organized into the following nine parts:

Part I	Foundational overview and definitions
Part II	Resource planning and modeling process
Part III	DTE Electric capacity position determination
Part IV	Modeling inputs and assumptions
Part V	Scenarios and sensitivities
Part VI	IRP modeling tools (Aurora and EnCompass)
Part VII	Overview of the IRP analysis results
Part VIII	Synthesis of results and risk assessment
Part IX	2026 IRP proposed course of action (PCA)

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Q8. Are you sponsoring any exhibits?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-2	2026 IRP Executive Summary
A-2.1	Starting Point Projected Capacity Position
A-2.2	PCA Projected Capacity Position
A-2.3	PCA Projected Revenue Requirement
A-2.4	Large Load Projected Revenue Requirement
A-2.5	Clean Energy Plan (Appendix A)
A-2.6	MIRPP Required Scenario and Sensitivity Capacity Credit Graphs
A-2.7	MIRPP Required Scenario and Sensitivity Energy Graphs

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

PART I: Foundational Overview and Definitions

Q10. For purposes of this testimony, what does the term "the team" mean?

A10. For purposes of this testimony, "the team" refers to me and the group of employees under my direction responsible for execution of the IRP modeling and supporting analyses (RP&TM).

Q11. Please provide a general overview of modeling.

A11. In general, utilities use modeling to inform the generation planning process. In the context of an IRP, utilities accomplish this by testing different portfolios across various scenarios and sensitivities.

Line No.

Q12. What is a portfolio?

A12. A portfolio represents a combination of starting point planning resources and model-selected resource changes under a specified set of market assumptions, resource alternatives, and other model inputs and constraints.

Q13. What were the primary modeling tools DTE Electric used in the IRP analysis?

A13. Primarily, the team used EnCompass. The Company also hired a third-party consultant, Siemens, to develop long-term fundamental commodity price projections. Siemens used the modeling tool, Aurora. Additionally, there were other models used by other Company subject matter experts (SMEs) or other third-party consultants. The additional models are shown in Table 1 below.

Table 1 Models used in the IRP process

Model & Description	Run by	Witness(es)
Aurora – market fundamentals	Siemens	Manning
EnCompass	DTE Electric	Manning
SERVM	PowerGem	Brooks
Transmission models	ITC	Djordjevic
Financial analysis	DTE Electric	Machi
EGLE MiEJScreen and EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool	DTE Electric	Marietta

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Q14. What is EnCompass?

A14. EnCompass is a power planning software by YES Energy. The Company utilizes EnCompass for capacity expansion and production cost modeling to develop prudent portfolios that meet customers' forecasted energy and capacity demand. Capacity expansion modeling is when the model optimizes and determines what the least-cost portfolio is based on the economics of alternative resources, market assumptions, existing resources, and load demand. Furthermore, production cost modeling provides additional detail for the least-cost portfolio determined in capacity expansion modeling by simulating how that selected portfolio operates on a more granular level, representing hourly dispatch decisions, energy production and operating costs more precisely.

Q15. How was EnCompass used in the IRP process?

A15. DTE Electric used EnCompass to model the Company's existing resources along with resource alternatives, cost inputs, market assumptions, and the load forecast. The team performed EnCompass's capacity expansion modeling across various scenarios and sensitivities to derive least-cost optimized portfolios. The optimized portfolios were then fed into the EnCompass production cost model to derive more precise portfolio cost estimates due to its hourly dispatch capability.

Q16. What is Aurora?

A16. Aurora is another capacity and production cost modeling tool used in the electric industry for IRP modeling. The software is an Energy Exemplar product.

Q17. How was Aurora used in the IRP process?

A17. As mentioned above, the Company engaged Siemens to develop the fundamental forecast across the Eastern Interconnect.[1] The Company has been working with Siemens since 2014, when it operated as PACE Global, on the fundamental modeling used in its long-term forecasts for integrated resource planning. A fundamental forecast includes modeling assumptions that were developed through a fundamental model across a larger footprint (Eastern Interconnect, or Midcontinent Independent System Operator (MISO)) to establish commodity prices for key commodities such as gas, capacity, and energy. Fundamental models include future retirement and replacement capacity expansion optimizations, capture supply and demand interactions across commodity markets, and provide more accurate projections for long-term analysis when compared to an extrapolation of a forward price curve for 20 years. Siemens' fundamental modeling derived the long-term forecasts for energy, capacity, emissions, and fuel commodity prices for various scenarios that the team used as direct inputs into the EnCompass model.

Q18. How are scenarios and sensitivities defined?

A18. A scenario is a view of the future based on broad market assumptions such as commodity prices, technology prices, load growth, and environmental regulations. A sensitivity is a case that is designed to test the impact of a specific uncertainty or variable. When a sensitivity is applied to each modeled scenario it is considered a

[1] The Eastern Interconnect is one of the two major alternating-current (AC) electrical grids in the North American power transmission grid. The Eastern Interconnection reaches from Central Canada eastward to the Atlantic coast (excluding Quebec), south to Florida, and back to the western Great Plains (excluding most of Texas). All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency. DTE Electric's service territory is in the Eastern Interconnection.

global sensitivity. Sensitivities are applied to the scenario to evaluate how changes to a particular assumption affect portfolio outcomes. For example, a scenario may assume a combination of policy changes, high load growth, and lower technology costs resulting in a distinct future market environment. A sensitivity applied to that scenario would then isolate and evaluate the impact of a single variable, such as higher natural gas prices, while holding the other scenario assumptions constant. This approach allows the Company to assess both the impact of broader future conditions and the effect of specific uncertainties on resultant resource portfolios.

Q19. Does the IRP include scenario analysis and global sensitivity analysis?

A19. Yes. Consistent with the revised Michigan Integrated Resource Planning Parameters (MIRPP) adopted by the Commission's December 18, 2025, order in Case Nos. U-21570 and U-21867, the Company evaluated the required MIRPP Scenario 1, the optional MIRPP Scenario 2, and multiple global sensitivities. For example, the Company evaluated the high gas sensitivity and the atypical weather conditions sensitivity across both MIRPP scenarios as global sensitivities. I discuss the scenarios and sensitivities the team modeled in Part V of my testimony.

Q20. What does the term 'starting point' refer to?

A20. The starting point is a common resource plan to benchmark against, to ensure consistency across all scenarios. I describe details about the resources and retirement assumptions included in the starting point for the IRP modeling in Part III of my testimony.

Q21. What is resource adequacy and why is it an important consideration when developing the Company's resource plan?

A21. Resource adequacy refers to the ability of the electric system to have sufficient resources available to serve customer demand, including periods of system stress. A resource portfolio that is not adequate under the applicable reliability criterion presents a greater risk that available generation and imports will be insufficient to serve customer demand, potentially resulting in firm load shed.

Q22. How did the Company consider resource adequacy in the context of this IRP?

A22. The Company considered resource adequacy through two complementary analyses in its 2026 IRP. First, the Company's EnCompass capacity expansion modeling was structured to develop portfolios that satisfy the applicable MISO Planning Reserve Margin Requirement (PRMR) under the assumptions used in that modeling. The PRMR reflects the amount of accredited capacity that a load-serving entity must demonstrate relative to its forecasted coincident peak demand. Witness Burgdorf discusses the PRMR and the accreditation of the Company's resources, and I discuss the Company's projected capacity position in Part III of my testimony.

Second, the Company retained PowerGEM to perform a probabilistic resource adequacy analysis of selected portfolios using SERVM. That analysis tested the portfolios' ability to serve hourly customer demand under numerous combinations of weather conditions, load uncertainty, and generator performance. PowerGEM evaluated the portfolios against a Loss of Load Expectation (LOLE) criterion of 0.10 event-days per year, commonly described as one day in ten years. Witness Brooks discusses the SERVM methodology and results.

Together, these analyses evaluate whether a portfolio contains sufficient accredited capacity to satisfy the applicable planning requirement and whether selected portfolios are expected to satisfy the LOLE criterion under a range of uncertain system conditions.

Q23. What is the 2026 IRP Executive Summary?

A23. The 2026 IRP Executive Summary, Exhibit A-2, is an overview of the process the Company engaged in throughout development of its IRP, that explains the current resources and circumstances of the Company, the information that underlies the modeling, the outreach process, and the PCA. The 2026 IRP Executive Summary is intended to highlight high-level analytical outcomes and planning insights from the IRP. Detailed modeling inputs, assumptions, scenario and sensitivity results, and supporting analyses are addressed through testimony of the Company's witnesses.

Q24. What is the planning period examined in the IRP analysis?

A24. The planning period, also referred to as the study period, examined in the IRP analysis is 2027 through 2046.

PART II: Resource Planning and Modeling Process

Q25. What are the resource planning and modeling steps associated with conducting DTE Electric's 2026 IRP process?

A25. As introduced by Witness Hajj, there are various steps associated with conducting DTE Electric's IRP process. There are eight steps listed below and my testimony will further detail steps 1, 2, 3, 4, 5, 6a-b, and 7. Additional details regarding step

Line No.

6 are provided by other witnesses. Specifically, Witness Marietta describes the environmental justice (EJ) analysis performed in step 6c, Witness Machi describes the financial analysis conducted in step 6d and Witness Djordjevic describes the grid reliability studies conducted in step 6e.

1. Review planning objectives
2. Develop scenarios and sensitivities
3. Develop inputs and resource alternatives
    a. Determine capacity position
    b. Develop modeling inputs
    c. Develop resource alternatives
4. Conduct and iterate modeling
5. Analyze results
6. Evaluate preliminary PCA and alternative portfolios
    a. Verify through resource adequacy
    b. Conduct risk assessment
    c. Conduct EJ analysis
    d. Conduct financial analysis
    e. Verify through grid reliability studies
7. Confirm final PCA
8. Develop IRP Filing

Q26. How was the first step, "review planning objectives," performed?

A26. As part of the first step, the team reviewed the planning objectives to confirm relevance and ensure they were considered throughout the IRP process. The

planning objectives, Safe, Reliable and Resilient, Affordable, Customer Accessibility, and Clean, are described in more detail by Witness Hajj in her testimony. Aspects of these objectives within the Portfolio Metric Evaluation process, discussed in Part VIII of my testimony, help synthesize scenario and sensitivity modeling results to inform the development of a preliminary PCA.

Q27. How was step two, "develop scenarios and sensitivities" performed?

A27. Scenarios and sensitivities were developed by considering IRP filing requirements, stakeholder input, and internal planning, and are explained in more detail in Part V of my testimony.

Q28. How was the third step, "develop inputs and resource alternatives" performed?

A28. The third step of the planning process involved three main components: (a) identifying the Company's capacity position; (b) developing modeling inputs; and (c) developing resource alternatives. The approach used to identify the capacity position is described in Part III of my testimony. The development of modeling inputs relied on a comprehensive set of data informed by other Company witnesses as well as supplemental modeling support performed by Siemens, as further discussed in Part VI of my testimony.

Lastly, to support the development of a reasonable and prudent plan, the Company evaluated a broad set of feasible resource options to meet customer demand. The team evaluated a multitude of technologies including natural gas with carbon capture and storage (CCS), nuclear, renewable generation, storage with a range of

durations, and demand-side management resources among others. These technologies are referred to as "resource alternatives." Some of the alternatives considered are emerging technologies, which Witness Pratt discusses in more detail. The costs and operating parameters of each alternative were inputs to the analysis. The assumptions were from a variety of sources and are covered in more detail by Witness Busse in his testimony.

Q29. How was the modeling analysis conducted in step four, "conduct and iterate modeling"?

A29. Different steps within the IRP process use various methods of modeling. The modeling conducted in the IRP analysis is an iterative process between the main IRP optimization modeling, resource adequacy modeling, and grid reliability modeling.

The team conducted the IRP optimization modeling using the software tool, EnCompass, explained in additional detail in Part VI of my testimony. The IRP model includes functionality to perform both capacity expansion and production cost modeling. Both functions were used in all EnCompass runs. An EnCompass run is the actual simulation or modeling performed using EnCompass and includes various scenarios and sensitivities, each combination resulting in a different portfolio. A portfolio represents the resource plan the model determines to be the optimal plan based on market assumptions and resource alternatives. For this IRP, under the various scenarios and sensitivities, the modeling team completed over 100 EnCompass runs.

Several resource portfolios were provided to PowerGEM to complete resource adequacy assessments, which are explained in more detail in Part VIII of my testimony and results discussed by Witness Brooks. The portfolios, including the preliminary PCA, were tested under a range of conditions to assess the portfolios' ability to reliably serve customers. Additional discussion regarding the resource adequacy analysis is in Part VIII of my testimony. Grid reliability modeling was performed by the International Transmission Company (ITC) and is explained by Witness Djordjevic in his testimony. ITC performed various transmission analyses on a number of portfolios including the PCA. The results provided valuable insight into the transmission impacts, projected enhancements and associated costs. These considerations informed the Company's selection of the PCA's feasibility, supporting its selection as a prudent plan.

Q30. How were the results analyzed in step five, "analyzing results"?

A30. As mentioned, each EnCompass run resulted in a portfolio. Under each scenario, the Company developed a "base" portfolio, which incorporated the applicable starting point inputs and assumptions and allowed the model to select incremental resources as needed, and was the basis for comparison. All sensitivities under the appropriate scenarios were compared to that respective base portfolio. The optimized resource mix selected in each sensitivity was reviewed to identify commonalities, and trends between different portfolios. This assessment helped identify recurring resource combinations as well as outliers and anomalies.

Additionally, to compare portfolios and synthesize results across scenarios and sensitivities, six main metrics of each portfolio were evaluated:

- Cost differentials

Line No.

- Environmental
- Reliability and capacity adequacy
- Market exposure and risk
- Flexibility and integration
- Resource diversity

The components are all a part of the Portfolio Metric Evaluation and described in more detail in Part VIII of my testimony. Reviewing the comparisons not only derived the least-cost plans across each scenario, but it also provided a quality check of the results within a given portfolio. The results between sensitivities vary due to the changing assumptions and are often not intuitive, requiring further investigation, adjustments, or could prompt additional sensitivities.

After the IRP modeling was completed and the results analyzed, the portfolios were narrowed down and a preliminary PCA was developed for further analysis such as resource adequacy modeling, risk assessment, and environmental justice.

Q31. What aspects of the IRP process are examined in step six, "Evaluate preliminary PCA and alternative portfolios?"

A31. Step six examines the preliminary PCA and alternative portfolios identified in Step five. These portfolios are further evaluated including resource adequacy modeling (step 6a) to confirm if the portfolios are resource adequate as discussed by Witness Brooks; the risk assessment (step 6b) as discussed in my Part VIII; EJ analysis (step 6c) as discussed by Witness Marietta; financial analysis (step 6d) discussed by Witness Machi; and verify grid reliability analysis (step 6e) as explained by Witness Djordjevic.

Line No.

Q32. How was step seven, "confirm the final PCA" completed?

A32. After completing the evaluations described in steps 5 and 6, the Company reviewed the results collectively. Based on those results, the Company confirmed and finalized the PCA as the most prudent plan balancing reliability, cost, and feasibility.

Q33. Which IRP process steps involved stakeholder collaboration and input?

A33. For the purposes of the 2026 IRP, stakeholder collaboration and input played a role throughout each step of the IRP process shown in Table 2. Stakeholder feedback was received through public forums, technical workshops, individual stakeholder discussions, and written comments received through email. Witness Hajj further describes these stakeholder outreach efforts.

Table 2 Stakeholder Collaboration and Input

IRP Process Step	Stakeholder Input
1. Review planning objectives	• Continued to utilize the stakeholder input from the 2019 IRP and feedback on planning objectives during the development of the 2021 Distribution Grid Plan
2. Develop scenarios and sensitivities	• Incorporated modeling inputs, scenarios and multiple sensitivities identified through the Commission order in Case Nos. U-21867 and 21570 resulting from 2025 collaboratives by the MPSC • Reviewed the data inputs at the technical workshops and addressed questions and comments • Evaluated additional sensitivities submitted by different stakeholders

Line No.

IRP Process Step	Stakeholder Input
3. Develop inputs and resource alternatives	• Incorporated resource alternatives from Case No. U-21193 Settlement Agreement (2022 IRP), which included a variety of Energy Waste Reduction (EWR) options and distributed generation (DG) as a resource • Included alternative resource options such as Virtual Power Plants (VPPs) and biomass in IRP modeling • Reviewed and benchmarked cost information provided by stakeholders against publicly available sources and the Company's All Source RFP
4. Conduct and iterate modeling	• Conducted a technical stakeholder session, with a topic specifically focused on modeling DG as a resource • Incorporated feedback from stakeholders and external industry experts related to modeling approaches
5. Analyze results	• Evaluated the performance of stakeholder supported scenarios, sensitivities, and resource alternatives • Considered stakeholder interests related to reliability, affordability, and resource diversity
6. Evaluate preliminary PCA and alternative portfolios	• Incorporation of EGLE's environmental analysis and specific portfolios analyzed • Customer feedback on key concerns including reliability and affordability

Q34. What is the PCA?

A34. The PCA is the Company's proposed resource plan for meeting customers' forecasted energy and capacity needs over the planning period. The PCA builds upon the starting point planning resources described in Part III and incorporates the incremental resource additions, retirements, and other changes identified below. For presentation purposes, the following summary identifies the incremental changes to the starting point. The Company has divided the additions and

retirements into three time periods: the first five years, 2027-2031; years six through ten covering 2032-2036; and the last ten years covering 2037-2046. The last ten years of the plan are more likely to change than the first ten years as emerging technologies develop further, updated information becomes available, market conditions and considerations evolve, and the Company files for future IRPs.

Incremental PCA additions and retirements during 2027-2031:

- Renewables – 1,050 MW of solar and 150 MW of wind
- Thermal –
    - 138 MW Michigan Power Cogeneration Project (Cogen)
    - 1,535 MW retirement of Monroe Units 3 and 4
    - ~1,400 MW Combined Cycle Gas Turbines (CCGT) (Two 1x1 configuration) with CCS installed in 2035
- Virtual Power Plants (VPP) – 22 MW of residential and 1 MW of commercial battery programs
- Conservation Voltage Reduction and Volt Var Optimization (CVR/VVO) – 10 MW

Incremental PCA additions and retirements during 2032-2036:

- Renewables – 4,550 MW of solar and 600 MW of wind
- Thermal –
    - ~700 MW CCGT (One 1x1 configuration) with CCS installed in 2035
    - 177 MW Extended Power Uprate (EPU) at the Fermi Nuclear Power Plant

- 1,531 MW retirement of Monroe Power Plant (Monroe) Units 1 and 2
- 76 MW retirement of Superior Peaking Station Units 1, 2, 3, and 4

- VPP – 14 MW of residential and 1 MW of commercial battery program
- CVR/VVO – 6 MW

Incremental PCA additions and retirements during 2037-2046:

- Thermal –
  - ~1,400 MW hydrogen (H_2) fueled Combustion Turbine (CT)
  - 1,270 MW (summer net capacity with DTE Electric owning 81.39% and Michigan Public Power Agency owning 18.61%) retirement of Belle River Power Plant (Belle River) natural gas peaking Units 1 and 2
- Energy Storage –
  - 1,663 MW compressed air storage
  - 50 MW iron air storage
  - 2,600 MW 4-hour lithium-ion batteries (not considered incremental as it replaces existing and planned batteries that reached end of life during this time period)
- VPP – 35 MW of residential and 1 MW of commercial battery program

While the PCA reflects the most prudent plan under the assumptions evaluated, the Company recognizes that market conditions and planning inputs will continue to evolve over time. As the planning horizon extends into the later years of this portfolio, the optimal resource mix may differ from the portfolio selected in this

IRP. Changes in market conditions, technology performance, policy requirements and other assumptions may influence future resource needs. Through future planning cycles, the Company will continue to refresh assumptions and emerging conditions which may result in changes in resource timing, selection and portfolio outcomes in future IRPs.

PART III: DTE Electric Capacity Position Determination

Starting Point

Q35. How was DTE Electric's starting point capacity position assessed in this IRP analysis?

A35. An assessment of the current state of the Company's capacity position was performed, building off the Company's 2026 capacity demonstration filing. That assessment became the starting point of the IRP optimization modeling.

Q36. How is the capacity position determined?

A36. The capacity position is determined by totaling the existing and approved resources' unforced capacity[2] for planning year (PY) 2027/2028 and resources' direct loss of load (DLOL) accredited capacity for PY 2028/2029 through the remainder of the study period. The capacity position also includes known or projected changes and subtracting from it the sum of the customer peak demand forecast plus MISO's planning reserve margin (PRM)[3] or collectively, the total

[2] Unforced capacity refers to the amount of reliable capacity that can be attributed to each resource that is eligible for the MISO capacity auction, i.e., it attempts to measure how much capacity (MW), adjusted for outages and derates, a resource contributes to system reliability during demand periods.
[3] MISO's planning reserve margin is a percentage set by MISO annually based on its required reserve margin, which is based upon its Loss of Load Expectation study and installed generating capability and projected energy demand in the MISO region. See MISO Tariff, Module E-1, Section 68A.2.1.

Line No.

MISO Planning Reserve Margin Requirement (PRMR).[4] The resultant difference would either be a projected capacity surplus or shortfall.

Q37. Why is the capacity position calculated using the PRMR?

A37. The MISO Tariff[5] requires that each load serving entity (LSE) must meet planning reserve margin requirements that recognize and are complementary to the reliability mechanisms of the State as described in more detail by Witness Burgdorf. MISO is the Planning Coordinator for the Midcontinent ISO region. DTE Electric's service territory is in MISO Zone 7.

Q38. What resource assumptions are included in the starting point?

A38. The starting point is comprised of the following existing resources, approved resources, and other planning assumptions reflected in the Company's IRP modeling:

- Fermi peaker units 3 and 4 retired
- Monroe retirement, Units 3 and 4 on December 31, 2028, and Units 1 and 2 on December 31, 2032
- Superior Peaking Station retirement on December 31, 2032
- Belle River retirement on December 31, 2039
- 5,577 MW of Commission-approved renewable build plan to meet the renewable portfolio standard (RPS)
- 2,961 MW of approved voluntary green pricing (VGP) renewables

[4] See MISO Tariff, Module E-1, Section 68A.7.
[5] MISO Tariff Module E-1 Section 68A, 69A-1 https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/, accessed September 4, 2026

Line No.

- 2% EWR in 2027 through 2028, then 1.5% EWR annual savings to comply with the legislative target, which considers the incremental load from Oracle America Cloud Services LLC (OACS) and Google LLC (Google)
- 636 MW of Demand Response (DR) in 2027 increasing to 638 MW in 2029, including forecasted capacity from the Company's existing CoolCurrents and Smart Savers programs and other DR resources, as described by Witness Leuker
- 1,000 MW of four-hour lithium-ion battery storage approved in the 2022 IRP to come online by 2029
- Existing Purchase Power Agreements (PPAs), peaking facilities not mentioned above, Blue Water Energy Center (BWEC), Ludington Pumped Storage Plant (Ludington), and Fermi 2 Nuclear Plant continue to be operational throughout the study period
- Planning assumptions associated with the contracted OACS and Google loads, including:
    - 1,600 MW of renewable resources associated with the Google VGP special contract
    - 1,803 MW of renewable resources included as a planning assumption associated with the OACS load[6]
    - 1,383 MW of 4-hour lithium-ion batteries for OACS, and 400 MW of 4-hour lithium-ion batteries and 50 MW of 8-hour lithium-ion batteries for Google, assumed to be in service by 2029

[6] The inclusion of the OACS renewable resource quantity in the starting point does not reflect Commission approval of specific renewable projects or a determination that particular projects are directly or exclusively assigned to OACS.

Line No.

- Short-term DR agreement and the contract providing 300 MW of Zonal Resource Credits (ZRC) with Google, each ending in May 2033

Collectively, the existing resources, approved or committed resource additions, and other modeling assumptions identified above comprise the "planning resources" used to assess the Company's starting point capacity position. The proposed resource plan builds upon these planning resources, but their inclusion in the starting point does not alter the regulatory or contractual status of any particular resource or planning assumption or mean that the Company is requesting new or additional Commission approval of each item identified above.

Q39. How are the CoolCurrents resource and associated investments reflected in the PCA?

A39. The PCA builds upon an aggregate starting point DR forecast that remains relatively constant over the planning period but reflects changes in the contributions of individual DR programs. The starting point forecast includes an increased contribution from CoolCurrents that depends on the planned 2028 through 2030 investments described by Witness Leuker. These investments are necessary to maintain and achieve CoolCurrents' forecasted capacity contribution within the Company's existing DR portfolio.

Q40. Was a starting point capacity shortfall identified in the first five years, 2027 - 2031, of the study period?

A40. A capacity shortfall was identified within the first five years of the study period from 2027 to 2031 only for the fall season of the PY 2028-2029. The team

determined the capacity position by subtracting the total starting point planning resources from the projected PRMR. See Witness Burgdorf's testimony for additional details on the determination of the PRMR. Refer to Exhibit A-2.1 Starting Point Projected Capacity Position for the annual detail. As shown in Exhibit A-2.1, the PRMR forecast is 10,151 MW and the projected planning resources total is 9,866 MW, thereby resulting in the projected capacity shortfall of 285 MW (less than 3 percent) in one season, the fall, of the PY 2028-2029. The capacity shortfall is driven by planned outages at Ludington; however, the shortfall does not persist throughout the remaining seasons of the first five-year period.

Q41. What was the starting point capacity shortfall identified in the second five years, 2032 - 2036, of the study period?

A41. The capacity assessment identified persistent, forecasted capacity shortfalls in the second five-year period as shown in Exhibit A-2.1. Following the planned retirement of the Monroe Power Plant Units 1 and 2 on December 31, 2032, the Company is projected to have a capacity shortfall of 213 MW in spring 2033 and increasing to 1,095 MW that summer. Looking further into this five-year period, the summer capacity shortfalls grow to 1,295 MW in 2034, 1,468 MW in 2035, and 1,654 MW in 2036. This increasing need for capacity is driven by the forecasted load growth associated with electrification and the declining accreditation values of resources over the study period. Witness Burgdorf goes into further detail about the DLOL projected capacity accreditation values.

Line No.

PCA

Q42. What is the Company's projected capacity position under the PCA?

A42. Exhibit A-2.2 presents the Company's projected capacity position under the PCA. The exhibit incorporates the incremental PCA additions and retirements identified in Part II of my testimony into the starting point capacity position. The resulting capacity position eliminates the persistent capacity shortfalls identified for 2032 through 2036 and provides sufficient accredited capacity to satisfy the Company's forecasted PRMR during that period.

PART IV: Modeling Inputs and Assumptions

Q43. What technologies and/or resource alternatives did the Company consider and evaluate in the EnCompass model?

A43. As Witness Busse discusses in his testimony, the Company conducted a review of resource alternatives. The resource alternatives included in EnCompass are:

- Natural gas
  - One 1x1 CCGT with CCS
  - Two 1x1 CCGT with CCS
  - Cogen
- Renewable[7]
  - Wind (on and offshore)
  - Utility scale solar
  - Customer owned distributed solar
  - Distribution connected front of meter small scale solar
  - Solar-storage hybrid

[7] Public Act 295 of 2008, available at https://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf, accessed September 4, 2026.

- Wood and biomass
- Storage
  - Lithium-Ion batteries (4-,6-, and 10-hour durations)
  - Compressed air (14-hour duration)
  - Molten Salt (10-hour duration)
  - Iron air (99-hour duration)
  - Residential and commercial battery VPP
- Nuclear
  - Small modular nuclear reactor (SMR)
  - EPU at Fermi Power Plant
  - Light water reactor
- Hydrogen fueled combustion turbine
- EWR (levels described by Witness Kupser)
- DR (programs described by Witness Leuker)
- CVR/VVO (described by Witness Singh)

Q44. How were the resource alternatives evaluated in EnCompass?

A44. The team modeled the alternatives as supply side resources in the EnCompass model with associated capacities, operating parameters, capital expense, and ongoing costs.

Q45. How were distributed energy resources (DER) modeled in the IRP?

A45. DER is considered a source(s) of electric power and associated technologies that are connected to a distribution system. DERs include generation resources, energy storage systems, and energy management programs that can either export power to

the grid or reduce system demand. DER serves as an umbrella category that encompasses distributed generation, VPPs and demand side management (DSM) resources. In the IRP, DERs were modeled by representing these key subcategories.

Q46. How were DG resources modeled in the IRP?

A46. In the context of this IRP, DG is considered a resource that is used by the customer to offset their energy consumption and is connected to the distribution system. The team incorporated the load forecast into EnCompass for each model run, which included an embedded baseline DG adoption forecast. The team also modeled customer-owned residential and commercial distributed solar as supply side resources and offered these resources to the model as capacity expansion project alternatives. Costs were based on utility benchmark incentive programs of $300/kW and energy export costs based on the current tariff. Additionally, there were three sensitivities conducted to evaluate 10%, 15%, and 20% DG adoption, which were provided as alternative load forecasts. The underlying DG assumed in the base load, the potential for the DG projects as alternatives and the sensitivity load forecasts are all described in more detail by Witness Sirwaitis in his testimony. See Part V for more information on the sensitivities.

Q47. How were EWR alternatives evaluated in EnCompass?

A47. As described by Witness Kupser, the Company evaluated various levels of EWR in the IRP: 1.5% (included in the starting point), 2.17%, 2.5%, maximum with 100% incremental cost, maximum with 50% incremental cost, maximum potential through 2032, down to 1.5%, and maximum potential through 2036, down to 1.5%. The seven different levels of EWR consist of different mixes of specific EWR end-

Line No.

uses that were combined to reach each level. The EWR inputs to the IRP include the aggregated end-use load shapes, annual costs, end effects, and avoided transmission & distribution (T&D) benefits for each EWR level. The T&D benefits are supported by Witness Singh's testimony while the remaining EWR inputs are described in more detail by Witness Kupser in his testimony.

First, in EnCompass, the team modeled a resource to represent the embedded EWR in the starting point energy sales and demand forecasts to remove EWR savings. Then the team modeled the seven EWR alternatives as projects with a fixed profile of energy savings derived from the aggregated end-use load shapes. The team modeled the program costs of each EWR alternative or level as fixed costs ($/year). The team also modeled additional benefits to represent avoided T&D benefits and end-effects, which represent the portion of EWR benefits that occur beyond the IRP study period. The team modeled avoided T&D benefits as a negative fixed cost rate in $/kW-year. The net present value (NPV) of end effects for each level of EWR was incorporated into EnCompass as a negative cost adder to reflect the benefit.

In select sensitivities, the EnCompass model could select from the seven levels of EWR as a resource starting in 2027 (first year). It was most efficient to model EWR with this methodology as opposed to the model varying between different levels of EWR between each year of the study period. Modeling the EWR levels with fixed profiles not only aligns with the optimized program mix and associated costs provided by Witness Kupser but also limits the number of projects included in EnCompass. Although EnCompass does not have a theoretical limit on the number of projects that can be included in its optimization, in practice it is limited by

modeling time and the amount of memory available on the computer system. As the number of resources increases, the problem size and modeling time increase as well. To allow the model to vary between the seven different levels of EWR, over the 20-year study period, would have added 140 different resources, which would have significantly increased modeling time.

Q48. How was DR evaluated in EnCompass?

A48. For this IRP, Witness Leuker provided various DR programs from the 2025 Demand Response Statewide Potential Study (DR Statewide Potential Study), along with those programs' respective annual capacities and costs. The Company modeled the incremental DR program alternatives as individual supply-side resources and modeled the cost for each program. The model had the option to select each incremental program between 2028 and the end of the study period in 2046. Separately, the team modeled the Company's existing DR portfolio, including CoolCurrents, on an individual program basis within the starting point. These programs could be dispatched according to constraints provided by Witness Leuker. See Witness Leuker's testimony for further discussion of DR and its role in this IRP.

Q49. What is CVR/VVO and how was it evaluated in EnCompass?

A49. CVR/VVO is a resource that provides benefits mainly to the distribution system by balancing line voltage and system reactive power to reduce system line loss and can also reduce energy and peak demand at the circuit level. The energy and peak demand reductions are highly dependent on the circuit. The team modeled potential CVR/VVO as a supply side resource that represents a range of MWs per circuit

accumulating to approximately 17 MW of peak demand savings. CVR/VVO is further explained by Witness Singh.

Q50. How were market energy purchases and sales evaluated in the IRP?

A50. The model was set up to allow hourly energy spot purchases and sales between DTE Electric and MISO based on economics. The energy sales and purchases were limited based on historical monthly on-and off-peak levels observed from 2018 to 2025. The hourly limits varied from 1,400 to 2,600 MW based on the month and time of day.

Q51. How were recent studies that indicate ways in which the capacity import or export capabilities can be potentially increased considered in the modeling?

A51. From a capacity expansion modeling perspective, studies evaluating future transmission upgrades and expansions, including MISO's Long Range Transmission Planning (LRTP) projects, did not directly impact the inputs used within the model. The modeling framework focuses on the Company's service territory, including its load forecast, existing resources and resource options, whereas the broader MISO market is represented through Siemens' market price forecasts, which model the full Eastern Interconnect as explained in Part I of my testimony. Consistent with this approach, the ability to make energy purchases and sales are represented using historical import and export levels reflecting the typical market participation that was observed between 2018 and 2025 as mentioned above. The model was set up with this approach to represent historical market behavior rather than the physical transfer capability of the transmission system. From a resource adequacy perspective, the transfer capability was modeled directly

by using MISO's reported Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values, which are explained more by Witness Burgdorf. To reflect the expansion of transmission capability, these limits were increased for the resource adequacy analysis, 2033 study year. LRTP is described in more detail by Witness Djordjevic.

Q52. How were market capacity purchases evaluated in EnCompass?

A52. Market capacity purchases represent potential capacity that could be purchased in the annual capacity auction; however, market capacity purchases were not available in IRP runs. This modeling constraint was imposed to ensure the resultant portfolios included enough capacity to meet the Company's customer demand without reliance on the capacity market. However, within EnCompass, the model can elect to have "unserved capacity" while incurring a penalty to defer capacity decisions based on economics that can be considered a market capacity purchase. In the majority of modeled cases, most unserved capacity occurred in a limited number of seasons during the 2040s and the amount was relatively low.

Q53. Does the modeling include any unabated natural gas resources?

A53. No. The modeling does not include any new unabated natural gas resources. While the Cogen facility uses natural gas as its fuel source, it is classified as a clean energy system per MCL 460.1003(i)(iii) as discussed by Witness Pratt. The only other natural gas resource option considered as an alternative in modeling were varying configurations of CCGTs with CCS installed by 2035. Additionally, hydrogen fueled CTs were included in modeling.

Q54. Were any constraints modeled limiting the number of resources that could be selected in the optimization?

A54. Yes. The team modeled different constraints for the various resources included in the optimization, as shown in Table 3.

Table 3 Resource Constraints

Resource Type	Constraint Throughout the Study Period
Cogen	Limited to one project addition in 2030.
Utility-scale Solar	No annual restriction; maximum cumulative additions limited to 59,400[8] MW throughout the study period.
Wind	No annual restriction; maximum cumulative additions limited to 6,300[8] MW throughout the study period.
Nuclear Uprates	Limited to one EPU project throughout the study period.
Light Water Reactor	Limited to one project addition per year starting in 2038.
Storage Resources	Maximum incremental additions are limited to 1,700 MW.
Combined-Cycle with CCS	Combined Cycle (CC) with 45Q is available for selection between 2032 and 2035. CC without 45Q is available beginning in 2036. In addition, CC without 45Q is limited to 1,374 MW, and total additions across CC with 45Q and CC without 45Q are limited to 2,748 MW.

Q55. What is the basis for the constraints listed in Table 3?

A55. The constraints listed in Table 3 were developed using a combination of resource specific considerations leveraging the Company's 2025 All-Source RFP and other analyses conducted to assess the feasibility of incorporating incremental amounts of specific resource types into the portfolio.

[8] Solar and wind constraints from Witness Bilyeu are rounded appropriately to accommodate the modeling set up of 150 MW build increments.

The Cogen facility and nuclear uprate options were limited to one per study period, as they were tied to specific project opportunities rather than generic resource additions. The light water nuclear reactor was also limited to one project per year to reflect the substantial size, complexity and construction time associated with large nuclear facilities. The renewable resource limits were informed by an analysis performed by Atwell, discussed in more detail by Witness Bilyeu. These limits represent an estimate of the amount of wind and solar that could be reasonably sited and developed throughout the study period. The storage constraint was developed through an assessment of the Company's ability to provide sufficient energy to charge additional storage resources while continuing to reliably serve customer demand. This analysis considered existing and planned storage resources, expected renewable generation growth and demand. Lastly, the combined cycles constraints were informed by the quantity of capacity identified in the All-Source RFP process in which this resource type was limited to 2,748 MW. It was also ensured that any combined cycle unit selected prior to the expiration of applicable IRA tax incentives were modeled with CCS technology by 2035, while units potentially selected after the expiration of those incentives were modeled without those tax credits available.

Q56. Why did the Company evaluate a constraint on incremental storage additions?

A56. The Company evaluated a constraint on incremental storage additions to assess how much additional storage could be supported by its generation fleet while maintaining the ability to reliably serve customer demand and provide sufficient energy to charge both existing and planned storage as well as any additional storage selected through capacity expansion modeling. Because energy storage consumes

energy during charging periods, it was important to evaluate the amount of incremental storage that could be supported by the available energy within the Company's system. Absent an appropriate constraint, the capacity expansion model could select an amount of incremental storage that exceeds the amount the system could reasonably charge while also reliably serving customer demand.

The analysis also recognized that the Company already expects approximately 3,000 MW of new battery storage capacity to be online by 2030, including storage resources associated with the 2022 IRP Settlement Agreement in Case No. U-21193 and contracted storage resources supporting OACS, and additional storage quantities included as planning assumptions associated with Google. Witness Schroeder further discusses the storage resources reflected in the Company's starting-point assumptions and PCA.

Combined with approximately 1,100 MW of existing pumped storage capacity, the Company expects more than 4,000 MW of storage resources on its system by 2030, before considering any additional storage selected through the capacity expansion modeling. Accordingly, the incremental storage constraint was intended to reflect the amount of additional storage that the Company's system could support beyond this substantial amount of existing and planned storage.

Q57. How did the Company determine the amount of incremental storage that could be supported by the system?

A57. The Company evaluated the forecasted peak day in 2030, July 18, as a representative day because it occurs after the contracted OACS and Google loads

and the storage resources and other resource assumptions associated with those loads are reflected in the modeling. For the 24-hour period, the Company assessed the total system demand, including both customer load and the charging requirements of the existing and planned storage resources reflected in the modeling. The Company compared that demand profile with the energy available from the Company's generating fleet and a representative level of market energy purchases based on historical import levels. The analysis identified the hours in which sufficient energy was available to serve customer demand and charge storage, as well as hours in which the available energy was insufficient to satisfy both requirements. Because additional renewable resources will be needed after 2030 to satisfy RPS requirements, the Company also considered the additional energy expected to be available from those future renewable additions in its assessment.

Q58. What did the analysis conclude regarding incremental storage additions?

A58. The analysis demonstrated that approximately 1,700 MW of additional storage capacity could be supported on an average 24-hour period of the representative peak day. Based on this result, the capacity expansion model was limited to selecting no more than 1,700 MW of incremental storage beyond the substantial amount of storage already planned for the system. When combined with the Company's existing and planned battery storage resources and Ludington pumped storage facility, total storage capacity exceeds 4 GW. This level of storage represents approximately 30% of the resources currently available on the Company's system.

Line No.

Q59. How were RPS requirements evaluated and incorporated in the IRP modeling?

A59. Modeling the renewable resources needed to support the Company's RPS requirements in the IRP was an iterative process involving coordination between the IRP modeling team and the Renewables team. Renewable resources included in the modeling consisted of approved resources from the 2024 Amended Renewable Energy Plan (REP), Case No. U-21662, as well as renewable resource quantities included as planning assumptions associated with the contracted OACS and Google loads. The Renewables team provided the applicable inputs for inclusion in the model. These resources are discussed in more detail by Witness Bilyeu.

Early in the modeling process, the team conducted an initial capacity expansion run that included a minimum renewable generation requirement designed to reflect the renewable resources expected to be needed to meet the 2035 RPS requirement. The results informed the renewable build assumptions incorporated into subsequent IRP modeling runs. Those assumptions reflected a more gradual annual build plan developed in coordination with the Renewables team.

Following the development of the preliminary PCA, the Renewables team reviewed the renewable resources reflected in the preliminary PCA. Based on that review and continued coordination between the teams, the renewable build assumptions were refined and incorporated into the PCA. Witness Bilyeu explains the renewable

resource assumptions and additions reflected in the PCA and the relationship between the IRP and the Company's concurrently filed Amended REP.

Q60. How did the Company address the Clean Energy Standard (CES) in modeling?

A60. For the CES, a different modeling approach from the RPS was used. Rather than imposing a CES compliance constraint within the capacity expansion model, the model was allowed to optimize resource selections based on economic considerations. This approach was appropriate because the resource alternatives being considered consisted of only clean energy, storage, or non-CO_2 emitting resources. For select portfolios, after the model identified the resource portfolios for various cases, a post modeling evaluation of CES compliance was completed by calculating CES for 2035 and 2040. This approach allowed the team to evaluate the CES performance based on the resources selected through the model's optimization, rather than forcing on an additional constraint, avoiding adding complexity, computational burden and extended run times to the model.

Q61. What resource types were included when calculating CES compliance after the capacity expansion modeling was completed?

A61. The resource types included in the CES compliance calculations are consistent with what are defined as clean energy system per MCL 460.1003(i). The resource types include:

- Renewables
    - Wind
    - Solar

Line No.

- Existing landfill gas and biomass contracts
- Nuclear
  - Light water reactor
  - SMRs
  - EPU
- Combined Cycles
  - CCGT w/CCS (90 percent at minimum)
  - Michigan Cogeneration Plant

PART V: Scenarios and Sensitivities

Q62. What scenarios were developed for this IRP?

A62. The DTE Electric 2026 IRP utilized three scenarios; two that were under the MIRPP, pursuant to the Commission's order implementing section 6t of 2016 PA 341, including MIRPP1 and MIRPP2; and one developed on Company assumptions Reference (REF26). For each of the three IRP scenarios, various sensitivities were run. The sensitivities included those required by Commission order, those requested by stakeholders, and some that the Company utilized to show a robust range of possible future outcomes. For more details specific to the underlying assumptions of each scenario, refer to the testimony of Witness Hajj.

Q63. What specific sensitivities are reflected in the IRP?

A63. The MIRPP, as well as the orders in the settlement agreements in Case No. U-21193 (DTE Electric's 2022 IRP) and Case No. U-21662 (DTE Electric's 2024 Amended REP) provide several required sensitivities, and the Company developed several on its own. Each sensitivity was applied to one or more scenarios. Most sensitivities

were performed under the three scenarios to represent a global sensitivity analysis. An overview of the sensitivities is described below:

Retirements: Also, based on the Case No. U-21193 IRP Settlement, the Company modeled retiring Monroe Units 1 and 2 in 2030 instead of the settled 2032 timeframe. Additionally, the Company modeled a sensitivity that retired the Greenwood Energy Center in 2045.

Resource Alternatives: Based on the U-21193 IRP Settlement, the Company was directed to model sensitivities for the replacement Monroe Units 1 and 2 that have a combination of one or more of the following: renewables, storage, EWR, demand response, distributed generation, and transmission, and without a new SMR, or gas- or hydrogen-fueled "dispatchable" resource.[9] This set of sensitivities also satisfy the Certificate of Necessity (CON) to evaluate the alternative resources that could defer or displace the proposed generation facilities.

Load (supported by Witness Sirwaitis): Several load forecast sensitivities were modeled identified below.

1. Low and high growth
2. Low, medium, and high large load growth
3. Atypical weather
4. 10%, 15%, 20% distributed generation
5. Alternative electric choice

[9] MPSC, Order in Case No. U-21193 Settlement Agreement, July 26, 2023. p 16.

Line No.

Renewables: The team modeled multiple sensitivities related to renewable resources including fixed annual build requirements, potential biomass PPA, and access to out-of-state renewables projects. Consistent with zonal modeling framework, the model does not explicitly differentiate resources based on geographic location. Therefore, out-of-state renewables were represented using assumptions reflecting higher performance characteristics as supported by Witness Bilyeu.

Storage: The team modeled various sensitivities related to energy storage including relaxed storage build constraints and the impact of longer duration technologies.

Energy Waste Reduction (supported by Witness Kupser): Seven levels of EWR were modeled as sensitivities including 1.5%, 2.17%, 2.5%, maximum with 100% incremental cost, maximum with 50% incremental cost, maximum potential through 2032 down to 1.5%, and maximum potential through 2036 down to 1.5%.

Other Demand Side Management (supported by Witness Leuker and Witness Singh): The team conducted sensitivities to evaluate the impact of various Demand Response programs, CVR/VVO, and VPPs on portfolio outcomes.

High Costs: Various sensitivities were modeled to evaluate cost uncertainty including higher natural gas price projections and increased capital cost assumptions for combined cycle and nuclear uprate resources.

Line No.

Q64. Were there any sensitivities submitted by stakeholders and were they included in the IRP analysis?

A64. Yes. Stakeholders submitted several sensitivity requests for consideration in the Company's IRP. Many of the requests received aligned with sensitivities the Company had already planned to perform. Table 4 below summarizes the sensitivities submitted by stakeholders and identifies whether and how they were incorporated into the IRP analysis.

Table 4 External Stakeholder Recommended Sensitivities

Stakeholder	Request No.	Request	Inclusion in IRP
Michigan EIBC, IEI, Advanced Energy United, and CGA	1	Model distribution-connected resources separately from bulk-connected resources: Explicitly model distribution-connected solar, storage, and solar + storage.	Yes, front of the meter, distribution connected small scale solar resources were incorporated into a sensitivity described in the stakeholder's request.
	2	Include a scenario with up to 10% of new solar and storage selected by the model as distribution-connected.	Yes.
	3	Model a Virtual Power Plant (VPP) program: Model a VPP program that is designed to aggregate behind-the-meter distributed energy resources (DERs), including both demand response (DR) resources as well as battery energy storage systems (BESS) to provide grid services and enhance reliability. These programs are often structured as initiatives that leverage customer-sited batteries and various DR resources to reduce	Yes, VPP programs (residential and commercial battery offerings) were modeled as selectable resources in several sensitivities.

Line
No.

Stakeholder	Request No.	Request	Inclusion in IRP
		peak demand, respond to grid emergencies, provide locational value, and improve resiliency.	
Clean Energy Organization	1	Evaluating high load factor customers should include the OACS.	Yes, the contracted OACS and Google LLC loads were incorporated into the base load forecast.
	2	The levels of energy purchase availability should be evaluated in combination with any sensitivities that include assumptions of additional high load factor customers being on DTE's system: Evaluating the energy purchase availability in combination with high load factor customer growth will be important to evaluate market risk around high load factor customers.	Yes, a sensitivity reflecting low data center growth included constrained energy purchase availability.
	3	High load factor customer(s) leaves the system before the end of the planning period: For example, if DTE assumes the high load factor customers are in the load forecast in 2030, then the sensitivity should have that high load factor load removed after 10 years so that the customer(s) are no longer included in the load forecast starting in 2040.	No. The Company did not model the requested sensitivity. The IRP base load forecast includes loads associated with executed, Commission-approved special contracts, consistent with the Company's treatment of other contracted commercial and industrial loads. Those special contracts contain long-term customer obligations, including minimum payment and termination provisions intended to address the financial consequences of early termination or material load underperformance. Based on those executed

Line
No.

Stakeholder	Request No.	Request	Inclusion in IRP
			contractual commitments and the associated contractual allocation of financial risk, the Company did not adopt the suggested modeling assumption that the contracted loads would leave the system after an arbitrary ten-year period. The agreements and Commission order in Case No. U-21990 address the contractual terms and protections applicable to OACS. The agreements and Company proposals pending in Case No. U-22058 address the contractual terms and protections applicable to Google.
5 Lakes Energy	1	Storage Price: Reduce storage price for all storage technologies by 10% increments down to 50% of the prices modeled in DTE's reference scenario. Include no cap on yearly storage build.	Yes, sensitivities were conducted reflecting reduced storage costs at the requested levels and a case with the storage build constraint removed.
	2	Varied Renewable Energy Build Rates Inside MISO Zone 7: In MISO Zone 7 (LRZ7), starting at yearly build rates of 50% of those included in the reference scenario, increase wind, solar, and storage yearly build rates in equal increments until reference scenario build rates are tripled.	Not explicitly as requested, however, multiple sensitivities were performed and included high renewable and storage additions.
	3	Wind Build Outside MISO Zone 7: Holding renewable energy build rates within LRZ7 constant, add the ability for	Not explicitly as requested. Resource location is generally treated as location-agnostic with the

Line
No.

Stakeholder	Request No.	Request	Inclusion in IRP
		DTE to procure 1GW of wind power on a yearly basis outside of LRZ7.	Company's modeling framework. However, there were sensitivities that included renewable resources with characteristics intended to represent out-of-state resources, including a case with 20% out of state renewables and another that required 550 MW of wind build a year.
Clean Grid Alliance	1	Reinstate the federal ITC/PTC for wind and solar by 2030: Re-instatement of clean energy Inflation Reduction Act (IRA) tax credits to evaluate how their near-term return would impact long-term system planning.	Yes, a sensitivity was performed assuming the reinstatement of the ITC/PTCs for wind and solar with continuation throughout the study period.
	2	Remove unabated natural gas options from IRP modeling: Remove unabated gas from the supply-side resource options given the Michigan clean energy standard requires 100% carbon-free generation by 2040, a date which falls within the planning horizon of this IRP.	Yes, in all instances, the supply-side resource options were limited to carbon free generation technologies only including abated gas or alternative fueled resources.
AE Clinic, Sierra Club, Environmental Council, Earth Justice, NRDC, and Troposphere Legal	1	New gas build constraints: do not allow for gas CCS (on new or existing units) and any new gas builds that have to be fully depreciated by 2040.	See above.
	2	Model data center load as 90% VGP or clean self-supply within six years of operation and that capacity needs are met with battery storage.	Yes, this request was conducted on the low data center growth sensitivity.

PART VI: IRP modeling tools (Aurora and EnCompass)

Q65. What models were used by the team in the IRP analysis?

A65. As discussed in Part I, the EnCompass model was the main resource planning tool used by the team for the IRP analysis and Siemens used Aurora to perform the modeling to derive the fundamental forecasts used in EnCompass.

Aurora

Q66. What is a fundamental forecast?

A66. A fundamental forecast includes modeling assumptions that were developed through a fundamental model across a larger footprint (e.g., Eastern Interconnect, or MISO) to establish commodity prices for key commodities such as energy, gas, and capacity. Fundamental models include future retirement and replacement capacity expansion optimizations, capture supply and demand interactions across commodity markets, and provide more robust projections for long-term analysis when compared to an extrapolation of a forward price curve for 20 years.

Q67. How were the energy market prices used in the IRP models determined?

A67. The energy market prices used in the IRP model were determined by blending the energy market forward pricing with the fundamental forecast for 2027-2029 to smoothly shift to the fundamental energy price forecast in 2030. The blending methodology applied a ratable adjustment between the forward prices and the fundamental forecast. The team used this methodology until the end of 2029. For years 2030 to 2046, the Company used the fundamental forecast from Siemens. There were different energy market price fundamental forecasts for each scenario

developed by Siemens. The transition methodology for energy prices was the same across scenarios.

Q68. Did Siemens run the fundamental forecast model for all three scenarios?

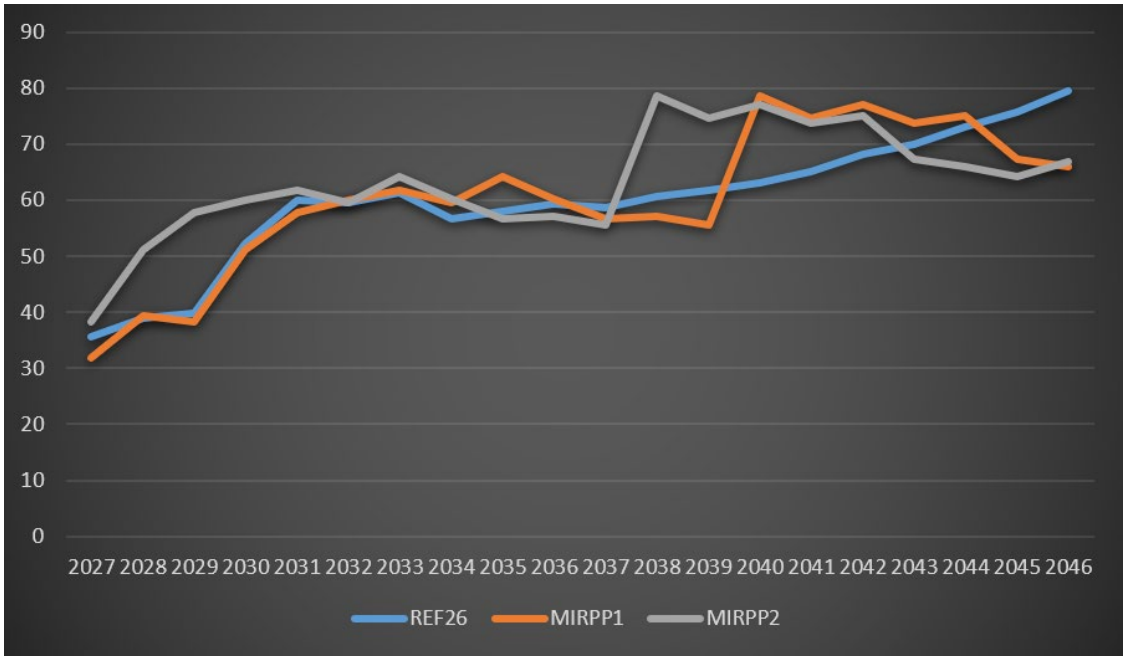
A68. Yes. The Eastern Interconnect fundamental model was run for all three scenarios. For the REF scenario, the Siemens' fundamental supply-and-demand model generated forecasts for gas prices, other fuel prices, and energy prices based on input assumptions including loads, and capacity costs. For the MIRPP1 and 2 scenarios the assumptions were guided by the MIRPP, which directed the incorporation of MISO Future 3 for MIRPP1 and MISO Future 1 for MIRPP2, which was dictated by the capacity additions and demand of those Futures. Both MIRPP1 and 2 scenarios used the 2025 Energy Information Administration's (EIA) natural gas price forecast as inputs as directed by the MIRPP into the fundamental model, which derived correlated market prices. For the high gas sensitivity, the 2025 EIA Annual Energy Outlook (AEO) high gas price was required to be used and input into the fundamental model to derive correlated market prices.

Q69. What was the resultant market price forecast for the three scenarios?

A69. The market price forecast for the three scenarios is shown in Figure 1 below.

Line No.

Figure 1 Annual Average Energy Market Price Forecast $/MWh



Q70. How was the gas price forecast determined for the IRP analysis?

A70. To maintain consistency between the gas prices and energy markets, the team used a methodology similar to the energy price forecast. The team blended forward fuel prices supported by Witness Swiech in all scenarios with the fundamental forecast from Siemens in years 2027-2029. For the years 2030-2046, the team used the fundamental prices for the scenarios. Additionally, the team added the forecasted transportation costs to the forecasted gas supply costs, as applicable, to represent the costs associated with transporting the gas from the relevant hub to the power plant. Transportation costs were based on existing agreements or general service tariff rates, depending on the plant and location, as described in more detail in Witness Swiech's testimony.

Q71. How was the capacity price forecast used in the IRP modeling determined?

A71. The capacity price forecast was part of the market forecasts derived from Siemens. The capacity price forecast was developed using a fundamentals-based approach similar to the design of the MISO Planning Resource Auction and underlying resource adequacy framework. The analysis reflects the relationship between projected supply and demand conditions, PRMR, and cost of new entry (CONE) for capacity resources.

At the MISO level, the forecast considered expected reserve margins over time and applied a downward sloping demand curve framework, where the capacity prices increase as the reserve margins tighten relative to the reserve margin requirements and CONE. This approach reflects the value of capacity needed to maintain reliability as defined by MISO's resource adequacy construct. Additionally, zonal considerations are incorporated to reflect local reliability requirements. When projected resources within Zone 7 are sufficient to meet local clearing requirements, the prices are generally aligned with MISO wide prices. However, if the local capacity becomes tight, Zone 7 prices spreads may occur, resulting in higher capacity values to incent additional local resources.

As mentioned previously in Part IV, market capacity purchases were not available for the model to select in the optimization.

Q72. How were the coal price forecasts determined for the IRP models?

A72. Coal prices were the same across all scenarios. The team added coal commodity costs to the applicable transportation rate to determine the delivered cost of coal,

Line No.

by route, to each generating facility. The team used a methodology that started with forward prices provided by Witness Swiech from 2027-2030. For 2031 and beyond, the Siemens' fundamental forecast inflation associated with coal prices was applied to the last year of the forward pricing.

Q73. Were any environmental allowance adders used in modeling?

A73. Nitrogen Oxide (NO_X) and Sulfur Dioxide (SO_2) adders were modeled to meet the constraints imposed by the Cross State Air Pollution Rule (CSAPR); the same prices were used in all scenarios since the team assumed no change in NO_X and SO_2 policy across scenarios. For Carbon Dioxide (CO_2), there is no CO_2 adder included in the scenarios consistent with the MIRPP requirements. This approach reflects both the absence of a current federal CO_2 market and continued uncertainty surrounding potential future CO_2 policy since a CO_2 pricing mechanism has not materialized in the United States. For the accounting of CO_2, the model calculates both total fleet emissions and the net short approach[10].

EnCompass

Q74. How does the EnCompass capacity expansion model function?

A74. The EnCompass capacity expansion model is an energy market simulation optimization tool that derives a portfolio to meet forecasted energy and capacity needs. To accomplish this, it utilizes the mixed integer programming (MIP) algorithm to minimize the objective value of the capacity expansion run. The team utilizes the typical day of the week construct during the capacity expansion runs

[10] CO_2 Accounting; Breidenich, Clare, Michael Gillenwater, and Wiley Barbour. "Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases." EPRI, March, 2019. https://www.epri.com/research/products/000000003002015044, , accessed September 4, 2026.

within EnCompass to reduce the problem size to one that can be solved. This construct reduces the number of days per month to seven.

Q75. How does the EnCompass production cost modeling function?

A75. After the team performs a capacity expansion run, the team then uses the derived portfolio in the production cost modeling within the same software. In contrast to the typical day of the week construct used in the capacity expansion run, the production cost run dispatches to all days of the year, thus providing more detailed modeling of the operating aspects. This level of granularity is possible because in production cost modeling, the software does not need to make capacity expansion decisions. The results of the production cost run are used for analyzing results and reporting.

Q76. Was the existing generation fleet modeled in EnCompass?

A76. Yes. The team modeled the Company's generation fleet, its costs and other operational parameters within EnCompass. The Company's Generation Optimization group provided operational inputs for the fossil units. The IRP modeling methods were similar to methods used in the Company's Power Supply Cost Recovery (PSCR) forecasts. These inputs include heat rate curves, outage schedules, random outage rates, variable operating and maintenance (VOM) costs used in dispatch, unit capacities, fuel blends, and emission rates. The Renewables organization provided the inputs for the existing and approved renewable projects, which are discussed further in Witness Bilyeu's testimony.

Line No.

Q77. How were the seasonal and operational characteristics of the resource types handled?

A77. The team modeled coal, gas, storage, and landfill gas resources in EnCompass to be economically dispatched. For other resources such as solar, wind, and EWR, the team modeled using the 'Net Dispatch Limit %' to generate at the appropriate net dispatch per year. This limit specifies the percentage of the maximum capacity to generate in each hour. For Fermi, the team used a monthly maximum capacity time series instead of a 'Net Dispatch Limit %', assuming the resource will operate at a constant capacity throughout each month to hit an energy target. This assumption is reasonable since Fermi cannot be turned on and off quickly or easily and is incapable of ramping.

Q78. How does the model consider forced outages?

A78. Within both the capacity expansion and production cost runs, the model takes the random outage rate percentage (ROR %)[11] across all hours of the simulation period.

Q79. How were derates modeled within EnCompass?

A79. The team modeled derates by specifying a percentage of the unit that is available within the 'Net Dispatch Limit %' field under a resource. If a resource was in a derate, the percentage specified was (Max Cap-Derate)/Max Cap*100.

[11] Random outage rate percentage, https://www.eia.gov/tools/glossary, accessed September 4, 2026.- "Forced Outage Rate (FOR) = The percentage of time that was a forced outage (FO) when the plant should have been running. How often is FO occurring when the plant should be running."

Q80. How was seasonal or limited availability of a resource addressed in EnCompass?

A80. Seasonal or limited availability was addressed by specifying maintenance outage dates, MW derates, and random outages rates for existing resources. For new resources, random outage rates were specified by publicly available sources as described by Witness Busse in his testimony.

Q81. How were industry best practices for modeling energy storage incorporated into EnCompass?

A81. Best practices for modeling energy storage are not defined by a single entity but reflect a set of evolving industry methodologies and practices informed through research, development, and practical application. These practices were informed by leading organizations such as the National Renewable Energy Laboratory (NREL) and Electric Power Research Institute (EPRI) as well as the MPSC's *Study of Long-Duration and Multiday Energy Storage* report and methodologies used in other utility IRPs.

Consistent with these practices, energy storage resources were modeled in EnCompass to capture key operational characteristics such as round-trip efficiency, duration, and capacity. Storage resource alternatives were co-optimized to provide multiple revenue streams including energy arbitrage and ancillary service markets. The modeling also incorporated imperfect foresight, as suggested in the *Study of Long-Duration and Multiday Energy Storage* report, to better reflect real world dispatch behavior and market conditions that also have the benefit of reducing production cost run times. In addition, the production cost modeling incorporates

high-resolution temporal inputs such as hourly load, renewable generation, and market price allowing for chronological dispatch of storage and other resources.

Q82. How did the Company evaluate the performance of energy storage under varied weather conditions?

A82. The Company evaluated the performance of energy storage under extreme and varied weather conditions through sensitivities and risk assessments. As identified in Part V of my testimony, the team modeled an atypical weather sensitivity as reflected in the load forecast. The wind and solar profiles provided by Witness Sirwaitis were then used to test performance under stressed and/or varied system conditions. In addition, resource adequacy modeling as explained by Witness Brooks assesses risk by incorporating the contribution of storage to system reliability considering changes in weather conditions and resource availability.

Taken together, this approach helps ensure that energy storage resources are evaluated in a manner that reasonably captures their operational capabilities, economic value, and reliability contributions consistent with current industry best practices.

Q83. What ancillary service products were modeled in EnCompass?

A83. The team modeled two ancillary service products administered by MISO within EnCompass. Spinning reserve and frequency regulation, also known as regulating reserve, were incorporated and allowed eligible resources including both traditional generation resources and storage to provide reliability support and capture additional potential market value.

Q84. What is spinning reserve?

A84. Spinning reserve refers to generating capacity online and available to increase output within a short time period to respond to unexpected system changes such as sudden loss of a generator or transmission outage. Traditional generators must already be operating below their maximum levels to provide spinning reserves, allowing them to quickly ramp up when needed. Several units of the Company's existing dispatchable fleet (Belle River, Monroe, Greenwood, Ludington, and Renaissance) as well as new natural gas and energy storage resources are capable of providing spinning reserves and were modeled as such. Energy storage resources offer operational advantages including the ability to quickly provide power, often within seconds, which enhances the system responsiveness to address system changes and events.

Q85. What is frequency regulation?

A85. Frequency regulation is used to maintain the electric system's operating frequency at a frequency of 60 Hz, which is necessary for reliable grid operation. Imbalances between electricity supply and demand can cause deviations in system frequency. When demand exceeds supply, frequency decreases and when supply exceeds demand, frequency increases. Frequency regulation resources can respond to these fluctuations by adjusting their output up or down to help maintain the balance between supply and demand. The resources capable of providing frequency regulation are similar to those capable of providing spinning reserves, with the exception of the Monroe units. Similar to spinning reserves, energy storage resources have the ability to respond quickly and efficiently to provide these services.

Q86. How were the ancillary service market prices determined?

A86. The team developed ancillary market prices for spinning reserve and frequency regulation by determining a correlative relationship between historical ancillary services and locational market prices (LMPs). This relationship was applied to the hourly LMPs to develop corresponding ancillary service price profiles consistent with changing market conditions. The prices were calibrated to historical revenues by applying a scaling factor to the prices to align with the Company's historical market outcomes. The ancillary service market price forecast is not intended to project future market outcomes or represent a precise market valuation. Ancillary services, particularly in MISO, historically have been relatively shallow and have significant variability. There is limited historical precedent to reliably project their long-term evolution of such a vastly changing market. The resulting ancillary service values should be interpreted as a reasonable proxy for incremental system value rather than a definitive estimate for future revenues. The final calibrated ancillary service profiles were incorporated into the EnCompass model and allowed eligible resources to capture additional revenue streams.

Q87. What level of Public Utility Regulatory Policies Act (PURPA) purchases were assumed?

A87. The Company included unchanged existing PURPA contracts (approximately 50 MW) throughout the study period (2027-2046) in the starting point for all scenarios, representing expected renewal of all existing PURPA contracts.

Q88. Does EnCompass produce revenue requirements for the modeled portfolios?

A88. Yes. EnCompass produces revenue requirement estimates on an annual basis for each modeled portfolio. The model bases the revenue requirements on the input financial assumptions and technology costs described by Witness Busse in his testimony, as well as projected operating costs of both existing and new resources that the team input into the model. The EnCompass revenue requirement component accounts for projected capital investments in the form of annual book depreciation expense and return on capital investment. The operating expenses, fuel purchases, net energy purchases, emission allowance costs, property taxes, and insurance are passed through costs and were included in the overall revenue requirement of the portfolio. The resulting revenue requirement estimates provide a consistent basis for evaluating and comparing relative economic impacts of other resource portfolios.

Q89. How can interested parties obtain copies of the EnCompass model?

A89. Interested parties may contact DTE_Electric_CleanVision@dteenergy.com for details and costs. It should be noted that experience, competency in dispatch/capacity expansion modeling, and/or training are required to properly run and interpret the model results.

PART VII: Overview of the IRP Analysis Results

Q90. How were the various portfolios compared across each scenario?

A90. Each scenario contained several sensitivities, of which the majority resulted in differing portfolios. The Net Present Value Revenue Requirement (NPVRR or NPV Rev Req) of the sensitivities under the same scenario were compared against

that scenario's starting point portfolio or base. For example, the starting point portfolio in the REF26 scenario was compared against the REF26 scenario sensitivity portfolio with an alternative retirement date for Monroe. The team ran the scenarios using a set of assumptions as the starting point. Refer to Part III for the resources included in the starting point. Additionally, for any capacity shortfalls, the model optimized the remaining portfolio with the available resources discussed in Part IV.

Q91. Can you describe the differences between the REF26 and the MIRPP1 scenarios' starting points?

A91. Yes. While the MIRPP1 scenario's starting point is mostly aligned with the REF26 scenario, MIRPP1 incorporates assumptions required by the Michigan Integrated Resource Planning Parameters including:

- A load forecast that reflects significant advancements toward electrification (for additional details, refer to the testimony of Witness Sirwaitis)
- EWR represents maintaining a 2.17%[12] savings level throughout the study period
- Natural gas prices are based on the latest EIA AEO forecast.

Q92. Can you describe the differences between the REF26 and the MIRPP2 scenarios' starting points?

A92. Yes. MIRPP2 uses the same starting point assumptions as the REF26 with the exception of the natural gas prices. Consistent with the Michigan Integrated

[12] Modeled with the 2.5% inputs provided by Witness Kupser as the MIRPP1 Scenario includes a higher load forecast.

Line No.

Resource Planning Parameters, MIRPP2 incorporates natural gas price projections from the latest EIA AEO forecast.

Q93. Can the results of sensitivities evaluated under different scenarios be directly compared to one another?

A93. No. As previously mentioned, scenarios are built upon a unique set of foundational assumptions, and each sensitivity is intended to be evaluated relative to the underlying scenario in which they are performed. This approach allows the Company to isolate and evaluate the effect of the sensitivity without conflating results with broader differences in the underlying or foundational assumptions.

Q94. What were the results of the REF26 Scenario sensitivities?

A94. The results are shown in Table 5. The EnCompass run results are grouped by the common sensitivity category.

Table 5 REF26 Scenario Results

Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
Starting Point	REF26_BASE	Base Case / Starting Point	-
Retirements	REF26_RET_MNR_30	Retire Monroe U1&2 12/31/2030	$280
	REF26_GRNW_45	Retire Greenwood 12/31/2045	$782
Resource Alternatives	REF26_NON_DISPATCH	Dispatchable resources are not selectable	($6,051)
	REF26_NO_H2_CT	Hydrogen fired CTs (H_2 CTS) are not selectable	($305)
	REF26_LDES_2032	LDES resources are fixed into the portfolio in 2032	$655
	REF26_NO_BUILD	Energy and capacity purchases only	$2,065

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Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
	REF26_SMR_34	SMR resources are fixed into the portfolio in 2034	$4,253
Load	REF26_LOW_LOAD	Lower load due to slower EV and electrification growth	($3,404)
	REF26_ATYPICAL_WEATHER	Atypical weather conditions	($978)
	REF26_CHOICE_RETURN	Limited electric choice customer migration	$2,010
	REF26_HI_LOAD	High load growth rate by at least a factor of two above base	$2,942
	REF26_LOW_DC_90P_RENEW	90 percent of the incremental data center load is served by renewables	$9,750
	REF26_LOW_DC	Incremental 2.0 GW of large load customer demand added	$11,776
	REF26_LOW_DC_LOW_PURCHASE	Limited energy purchases available on the LOW_DC sensitivity	$11,861
	REF26_MEDIUM_DC	Incremental 5.9 GW of large load customer demand added	$34,355
	REF26_HIGH_DC	Incremental 9.3 GW of large load customer demand added	$53,420
Renewables	REF26_PTC_RETURN	PTCs are reinstated beginning in 2030 for wind and solar resources	($2,598)
	REF26_RENEW_REDUCTION	Limited ability to procure or construct 20 percent of renewables in Michigan	($84)
	REF26_BIOMASS_PPA_5YR	Fixed in a 5-year biomass PPA	$295
	REF26_BIOMASS_PPA	Fixed in a long-term biomass PPA	$428
	REF26_WIND_550	550 MW of wind fixed into the portfolio every year	$2,710
	REF26_DISTRIBUTION_SOLAR	10 percent of incremental solar is distribution connected front of meter	$310
	REF26_LAND_RENEW_CAPPED	Land based renewables capped at 60%, CES met through other clean energy resources	$6,073
	REF26_3X_RENEW_STORAGE	Tripled the amount of renewables and storage selected in the base	$10,036
Storage	REF26_NO_BAT_CONST	Removed storage constraints	($2,324)
	REF26_STORAGE_LOW_COST	Lowered storage costs by 50 percent	($1,680)
	REF26_NO_COMP_AIR	Limited compressed air storage from being selected in the optimization	($602)
EWR	REF26_EWR_OPT	EWR selectable and optimized between the seven available programs	($1,347)

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Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
	REF26_2_5_EWR	The 2.50% EWR program was fixed into the portfolio	($1,465)
	REF26_2_17_EWR	The 2.17% EWR program was fixed into the portfolio	($1,295)
DSM	REF26_DSM	DR programs and CVR/VVO are selectable	($1,015)
	REF26_VPPS	VPPs are selectable	($192)
High Costs	REF26_CCGT_HI_COST_10p	Increased the cost of the CCGT by 10 percent	$374
	REF26_EPU_HI_COST	EPU costs doubled	$384
	REF26_HI_GAS	Gas prices reflect the EIA high scenario	$4,262

Q95. What key observations can be drawn from the REF26 Scenario sensitivities?

A95. Across the REF26 Scenario sensitivities, the resource portfolio remains generally consistent. In most cases, the model selects two 1x1 CCGT units in 2032 driven by the energy and capacity needs associated with the retirement of the Monroe Units 1 and 2. The optimization also selects a substantial level of long duration energy storage (specifically compressed air storage) in 2037 taking advantage of the IRA tax credits for storage resources prior to expiration. Hydrogen fueled CTs are generally selected to replace capacity associated with the retirement of the Belle River gas units at the end of 2039. Beyond the renewable resources that are needed to satisfy the RPS requirements, the optimization generally does not select additional renewable resources, suggesting that other resources provide a more economic means of meeting system needs under the modeled assumptions in the Reference scenario.

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Q96. Can you provide more detail on the sensitivities that were run on the REF26 Scenario?

A96. Yes. Several observations from the REF26 Scenario sensitivities are explained below:

- Retirements –

Sensitivity	Key Observations
REF26_RET_MNR_30	Early retirement of Monroe Units 1 and 2 is not economic and the portfolio experienced unserved energy and capacity in 2031.
REF26_GRNW_45	Early retirement of Greenwood resulted in higher portfolio costs in comparison to maintaining it through the study period due to the addition of H_2 CTs.

The results of retiring Monroe Units 1 and 2 in 2030 indicate that accelerating the retirement was not an economic option. Because the CCGT resource options were subject to the earliest in-service date of 2032, the model was unable to advance the addition of that resource(s) to replace the retired capacity. Instead, the optimization selected 100 MW of 4-hour batteries in 2031 and relied on the addition of two 1x1 CCGTs in 2032 to meet longer term capacity needs. As a result, the portfolio experienced unserved energy and capacity in 2031 prior to the CCGTs coming online.

Advancing the Greenwood retirement to 2045 resulted in approximately 700 MW of hydrogen fueled CT capacity in 2045, which increased the overall portfolio costs in comparison to maintaining Greenwood through the study period.

Line No.

- Resource alternatives –

Sensitivity	**Key Observations**
REF26_NON_DISPATCH	Without dispatchable replacements, the portfolio had heavy reliance on external markets to meet energy demands.
REF26_NO_H2_CT	Lower cost portfolio replacing H_2 CTs with CCGTs in 2043.
REF26_LDES_2032	Higher cost portfolio and does not eliminate the need for CCGT resources.
REF26_NO_BUILD	Substantial unserved energy and capacity across multiple seasons and years, indicating that replacement resources are necessary to serve customer demand and maintain system reliability.
REF26_SMR_34	Higher cost portfolio due to the addition of SMRs in 2034.

While the non-dispatchable sensitivity resulted in one of the lowest cost portfolios, it achieved this outcome by selecting the maximum level of EWR, DR, VPPs, battery, and LDES (Long-Duration Energy Storage). Despite these additions, unserved energy was observed and the portfolio relied significantly on energy purchases to meet customer demand.

Requiring LDES to come online in 2032, rather than in later years of the study period, did not eliminate the need for dispatchable capacity additions, as the model still selected two CCGTs in 2032.

- Load-

Sensitivity	**Key Observations**
REF26_LOW_LOAD	Lower demand results in lower portfolio costs by decreasing the need for new resources and lowering production costs.

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Sensitivity	**Key Observations**
REF26_ATYPICAL_WEATHER	Selected additional 4-hour battery storage in 2035 and required less LDES than other sensitivities.
REF26_CHOICE_RETURN	Higher cost portfolio driven by accelerated battery storage builds and additional H_2 CTs. There was also unserved energy in 2030.
REF26_HI_LOAD	Higher demand increased portfolio costs due to the need for additional resources and had greater reliance on energy market purchases to meet customer demand.
REF26_LOW_DC_90P_RENEW	Lower portfolio costs relative to REF26_LOW_DC as higher renewable builds displaced CCGTs, however, there was greater dependence on energy market purchases. This portfolio also had unserved energy throughout the study period.
REF26_LOW_DC	Additional large load customer demand drove the need for additional CCGTs in 2032.
REF26_LOW_DC_LOW_PURCHASE	Resulted in the same resource portfolio as REF26_LOW_DC but with higher costs due to reduced availability of market purchases and increased the operations of the generation fleet.
REF26_MEDIUM_DC	Additional large load customer demand required additional resources including DSM, renewables, CCGTs and H_2 CTs.
REF26_HIGH_DC	

Line No.

Across the load growth sensitivities with higher demand relative to the base, the incremental resource additions were generally met through CCGT and hydrogen fueled CT additions. The model also selected incremental demand side management resources including DR, EWR, and VPPs to help meet the assumed demand growth.

The atypical weather sensitivity resulted in a slightly different portfolio in terms of the storage resources selected, this was due to year-to-year fluctuations in energy and peak demand assumptions described by Witness Sirwaitis.

- Renewables –

Sensitivity	**Key Observations**
REF26_PTC_RETURN	Lower overall portfolio costs, however, no additional renewable resources were selected until the last year of study with 6,300 MW of wind added in 2046.
REF26_RENEW_REDUCTION	Lower portfolio costs were driven by higher out-of-state renewable capacity factors; however, the analysis does not capture or quantify the additional procurement and operational risk associated with out-of-state resources.
REF26_BIOMASS_PPA_5YR	Higher portfolio costs with limited change to the resource portfolio. The 5-year PPA defers 100 MW of 4-hour batteries, while the longer PPA displaces the need for a H_2 CT.
REF26_BIOMASS_PPA	
REF26_WIND_550	Adding 550 MW of wind each year increased portfolio costs but replaced CCGTs in the 2040s with H_2 CTs.

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Sensitivity	Key Observations
REF26_DISTRIBUTION_SOLAR	Higher portfolio costs were driven by increased costs and lower capacity factors associated with small scale front of meter distribution connected solar resources.
REF26_LAND_RENEW_CAPPED	No alternative renewable resources were selected, instead, additional CCGTs were added in 2032 and SMRs in the 2040s.
REF26_3X_RENEW_STORAGE	Tripling the renewable and storage builds resulted in the displacement of CCGT and H_2 CT additions but resulted in higher portfolio costs.

In general, the sensitivities that included additional renewable annual builds resulted in higher overall portfolio costs due to the additional capital investment and reduced flexibility in resource optimization. The only exception to this was the sensitivity that assumed out of state renewable resources (REF26_RENEW_REDUCTION). This sensitivity resulted in lower portfolio costs due to the renewables producing additional energy since states such as Arkansas and Wisconsin have higher capacity factors for solar and wind, respectively. However, as mentioned previously, the zonal modeling framework is generally location agnostic and does not capture operational risks such as transmission congestion, availability, and deliverability. These factors could impact the overall portfolio costs and performance of the renewables more generically modeled.

The REF26_DISTRIBUTION_SOLAR sensitivity tested the cost of meeting RPS targets with front of meter distribution connected resources. Although these resources can provide benefits such as avoided transmission

Line No.

and distribution savings, the resulting portfolio was not cost effective as small scale projects generally lack the economies of scale relative to utility sized renewable resources.

In the REF26_LAND_RENEW_CAPPED sensitivity, in addition to land based renewables, storage and hydrogen fueled resources were also restricted as they do not qualify as clean energy resources for CES compliance purposes. Under these constraints, the model did not select other renewable options such as offshore wind or biomass. Instead, the optimization selected additional CCGTs and 2,400 MW of SMRs in the later years of the study period, resulting in a higher cost portfolio.

- Storage –

Sensitivity	**Key Observations**
REF26_NO_BAT_CONST	The model accelerated 4-hour battery storage into the early 2030s and deferred the CCGTs to the 2040s. Additional LDES was selected in 2037. While the portfolio resulted in lower costs, it had unserved energy and relied on energy market purchases to meet customer demand.
REF26_STORAGE_LOW_COST	Lower storage costs resulted in the selection of 6-hour battery storage in 2037 instead of LDES, leading to a lower portfolio cost.
REF26_NO_COMP_AIR	In not allowing compressed air storage in the optimization, the model selected additional 4-hour battery storage as a replacement, indicating that compressed air is the optimal LDES technology among the options in the model.

Line No.

As mentioned previously, the model includes a storage build constraint that limits the cumulative storage additions to 1,700 MW. When this constraint was removed in REF26_NO_BAT_CONST, the model accelerated the timing of the 4-hour to earlier years of the planning horizon rather than being added later to replace batteries reaching end of their useful lives. This sensitivity also resulted in additional LDES in 2037, increasing from approximately 1,600 MW to 2,300 MW. The resulting storage builds deferred the CCGT additions in 2032 to 2043. While the portfolio costs were lower overall, unserved energy was observed and there was greater reliance on the energy market to serve customer demand.

- EWR –

Sensitivity	**Key Observations**
REF26_EWR_OPT	Of all the seven EWR levels provided by Witness Kupser and described in Part V of my testimony, the maximum with 50% incremental cost was selected.
REF26_2_5_EWR	While both sensitivities resulted in lower overall NPVRRs through 2046, those savings did not materialize until after 2040 due to differences in resources selections in the outer years. As discussed by Witness Kupser, the Company's review of program deliverability indicated that achieving savings levels of 2.17% and 2.5% is not feasible, as the necessary energy savings potential does not exist.
REF26_2_17_EWR	

All three EWR sensitivities (e.g. 2.17%, 2.5%, and optimized EWR levels) resulted in unserved energy, increased reliance on energy market purchases and higher levels of renewable curtailment relative to the base.

Line No.

- DSM –

Sensitivity	**Key Observations**
REF26_DSM	The model selected the CVR/VVO and DSM options available resulting in reduced portfolio costs driven by the deferral of 100 MW of 4-hour battery storage and replaced the CCGTs in 2040 with H_2 CTs.
REF26_VPPs	The inclusion of VPPs lowered costs by deferring 100 MW of 4-hour battery storage and displacing a H_2 CT.

The DSM and VPP sensitivities demonstrated the value of demand-side management resources in lowering portfolio costs, reducing and deferring future capacity additions.

- High costs –

Sensitivity	**Key Observations**
REF26_CCGT_HI_COST_10p	The resulting resource portfolios remained aligned with the base through the 2030s despite the higher costs. Differences between these portfolios did not emerge until the 2040s.
REF26_HI_GAS	
REF26_EPU_HI_COST	Delayed selection of the EPU from 2036 to 2040.

As expected, all sensitivities resulted in higher NPVRRs relative to the REF26_BASE, as a specific assumption of the optimization became more expensive. In all cases, the portfolios remained mostly unchanged, which demonstrates that the resources selected in the base are optimal and cost-effective options even under higher cost assumptions.

Line No.

Q97. What is the least-cost portfolio of the REF26 Scenario?

A97. The least-cost portfolio in the REF26 Scenario is the REF26_NON_DISPATCH sensitivity, which is $6,051 million less than the base. This outcome is driven by the increase in demand side management resources selected in this sensitivity which reduces the need for additional resources relative to the base. However, as mentioned previously, unserved energy is observed and there is a significant increase in energy market purchases.

Q98. What were the results of the MIRPP1 Scenario?

A98. The results of the MIRPP1 Scenario are shown below:

Table 6 MIRPP1 Scenario Sensitivity Results

Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
Starting Point	MIRPP1_BASE	Base Case / Starting Point	-
Retirements	MIRPP1_RET_MNR_30	Retire Monroe U1&2 12/31/2030	$351
	MIRPP1_GRNW_45	Retire Greenwood 12/31/2045	$943
Resource Alternatives	MIRPP1_NON_DISPATCH	Dispatchable resources are not selectable	($6,198)
	MIRPP1_NO_H2_CT	Hydrogen fired CTs are not selectable	$119
	MIRPP1_LDES_2032	LDES resources are fixed into the portfolio in 2032	$815
	MIRPP1_NO_BUILD	Energy and capacity purchases only	$21,085
	MIRPP1_SMR_34	SMR resources are fixed into the portfolio in 2034	$3,245
Load	MIRPP1_ATYPICAL_WEATHER	Atypical weather conditions	($455)
	MIRPP1_LOW_DC_90P_RENEW	90 percent of the incremental data center load is served by renewables	$14,370
	MIRPP1_LOW_DC	Incremental 2.0 GW of large load customer demand added	$13,856

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Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
	MIRPP1_LOW_DC_LOW_PURCHASE	Limited energy purchases available on the LOW_DC sensitivity	$13,840
	MIRPP1_MEDIUM_DC	Incremental 5.9 GW of large load customer demand added	$38,774
	MIRPP1_HIGH_DC	Incremental 9.3 GW of large load customer demand added	$60,593
Renewables	MIRPP1_PTC_RETURN	PTCs are reinstated beginning in 2030 for wind and solar resources	($2,502)
	MIRPP1_RENEW_REDUCTION	Limited ability to procure or construct 20 percent of renewables in Michigan	($137)
	MIRPP1_BIOMASS_PPA_5YR	Fixed in a 5-year biomass PPA	$846
	MIRPP1_BIOMASS_PPA	Fixed in a long-term biomass PPA	$849
	MIRPP1_10_DG	DG resources at 10 percent of load	$373
	MIRPP1_15_DG	DG resources at 15 percent of load	$1,206
	MIRPP1_20_DG	DG resources at 20 percent of load	$1,996
	MIRPP1_WIND_550	550 MW of wind fixed into the portfolio every year	($1,601)
	MIRPP1_DISTRIBUTION_SOLAR	10 percent of incremental solar is distribution connected front of meter	$252
	MIRPP1_LAND_RENEW_CAPPED	Land based renewables capped at 60%, CES met through other clean energy resources	$7,487
	MIRPP1_3X_RENEW_STORAGE	Tripled the amount of storage selected in the base	$8,696
Storage	MIRPP1_NO_BAT_CONST	Removed storage constraints	($2,473)
	MIRPP1_STORAGE_LOW_COST	Lowered storage costs by 50 percent	($1,381)
	MIRPP1_NO_COMP_AIR	Limited compressed air storage from being selected in the optimization	($402)
DSM	MIRPP1_DSM	DR programs and CVR/VVO are selectable	($661)
	MIRPP1_VPPS	VPPs are selectable	($144)

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Line No.

Theme	Sensitivity Name	Description	
High Costs	MIRPP1_CCGT_HI_COST_10p	Increased the cost of the CCGT by 10 percent	($1,712)
	MIRPP1_EPU_HI_COST	EPU costs doubled	$426
	MIRPP1_HI_GAS	Gas prices reflect the EIA high scenario	$158

Q99. Are there any key observations taken from the MIRPP1 Scenario sensitivities?

A99. Yes. The results are very similar to the REF26 Scenario, although as mentioned previously there are some key assumptions that are different. The MIRPP1 Scenario has a higher load forecast as described by Witness Sirwaitis which drives the need for additional renewable resources to meet RPS. In addition, the EWR level is set to a higher savings level and includes the EIA AEO natural gas price.

Q100. Can you provide more detail on the sensitivities that were run on MIRPP Scenario 1?

A100. Yes. Several observations from the MIRPP1 Scenario sensitivities are explained below:

- Retirements –

Sensitivity	Key Observations
MIRPP1_RET_MNR_30	The higher EWR savings assumption in the MIRPP1 Scenario reduced the capacity need avoiding new resource additions in 2031. However, the portfolio had heavy reliance on energy market purchases in the early 2030s.
MIRPP1_GRNW_45	Retirement of Greenwood resulted in the addition of approximately 700 MW of H_2 CTs, increasing the portfolio costs.

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- Resource Alternatives –

Sensitivity	Key Observations
MIRPP1_NON_DISPATCH	The model selected the maximum with 50% incremental cost EWR program. Additionally, 1,500 MW of wind was added between 2043 and 2046, however, unserved energy was observed throughout the study period.
MIRPP1_NO_H2_CT	The resource portfolio remained consistent with the base, but portfolio costs increased due to higher reliance on energy market purchases in 2042.
MIRPP1_LDES_2032	Fixing LDES into 2032 did not eliminate the need for the CCGTs but increased the portfolio costs.
MIRPP1_NO_BUILD	Substantial unserved energy and capacity across multiple seasons and years, indicating that replacement resources are necessary to serve customer demand and maintain system reliability.
MIRPP1_SMR_34	The inclusion of approximately 1,400 MW of SMR resources in 2034 shifted later builds, replacing CCGT additions with H_2 CTs resulting in a higher cost portfolio.

- Load –

Sensitivity	Key Observations
MIRPP1_ATYPICAL_WEATHER	Increased variability in energy and peak demand accelerated storage into 2035.
MIRPP1_LOW_DC_90P_RENEW	Fixed renewable and storage additions displace CCGTs and H_2 CTs. Although more than 4,500 MW of incremental storage and 6,500 MW of incremental renewable resources were added relative to the LOW_DC sensitivity, unserved energy was observed throughout the

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Sensitivity	Key Observations
	study period. The portfolio also relied heavily on energy market purchases to meet customer demand.
MIRPP1_LOW_DC_LOW_PURCHASE	The resource portfolio remained consistent with the LOW_DC sensitivity until the 2040s with different CCGT timing and H_2 CT additions.
MIRPP1_LOW_DC	Additional large load customer demand drove the need for additional CCGTs in 2032 and approximately 1,400 MW of H_2 CTs in the early 2040s.
MIRPP1_MEDIUM_DC	Higher large load customer demand required additional resources including DSM, renewables, CCGTs and H_2 CTs.
MIRPP1_HIGH_DC	

The load sensitivities under the MIRPP1 Scenario primarily focus on the impacts of large load customer growth. Consistent with the Reference Scenario results, the additional demand from these high load factor customers requires incremental capacity. In these sensitivities, this additional demand is served by more CCGTs and hydrogen fueled CTs. It is important to note that these sensitivities are intended to solely evaluate the resources selected in a portfolio and were developed as directed by the MIRPP. Under all Scenarios, these sensitivities do not incorporate assumptions regarding customer specific contractual arrangements, tariffs, other cost recovery mechanisms, or other commercial structures that may dictate how the data center customers contribute to the cost of the resources needed to serve this additional load. This set of sensitivities should be

Line No.

viewed as a planning exercise designed to assess resources needs under higher load conditions.

- Renewables –

Sensitivity	**Key Observations**
MIRPP1_PTC_RETURN	Exploring the potential reinstatement of renewable tax credits decreases portfolio costs due to the tax benefits. No additional renewable resources were selected until 2046 when 5,400 MW of wind was added.
MIRPP1_RENEW_REDUCTION	The resource portfolio remained consistent with the MIRPP1_BASE, except for the iron air storage being accelerated to 2044. While portfolio costs decreased, the analysis does not capture or quantify the additional procurement and operational risk associated with out-of-state resources.
MIRPP1_BIOMASS_PPA_5YR	Higher portfolio costs resulted from additional biomass resources with CCS in the 2040s displacing CCGT additions during that period.
MIRPP1_BIOMASS_PPA_20YR	
MIRPP1_10_DG	Increased distributed generation resulted in higher portfolio costs due to additional incentives needed to drive higher levels of customer adoption.
MIRPP1_15_DG	
MIRPP1_20_DG	
MIRPP1_WIND_550	Annual wind additions deferred the CCGTs from 2032 to 2044. To fill the capacity need in 2033, approximately 600 MW of 4-hour battery storage was selected in 2033.
MIRPP1_DISTRIBUTION_SOLAR	Allocating 10 percent of the solar additions as front of meter distribution connected resources resulted in only minor changes in the resource portfolio.

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Sensitivity	Key Observations
MIRPP1_LAND_RENEW_CAPPED	Limiting resource options to clean energy resources and non-land-based renewables results in a portfolio with approximately 2,700 MW of CCGTs in 2032 and nearly 2,900 MW of SMRs in the 2040s.
MIRPP1_3X_RENEW_STORAGE	Tripling renewable and storage additions from the REF26_BASE displaced CCGTs and H_2 CTs, however the resulting portfolio was higher in costs.

Under this MIRPP1 Scenario, different DG assumptions are assessed through sensitivities that are consistent with the MIRPP requirements. These sensitivities consider DG penetration levels of 10%, 15%, and 20% of load. To support these higher levels of DG, additional costs are assumed associated with incentive costs to drive increases in DG participation as discussed by Witness Sirwaitis.

- Storage –

Sensitivity	Key Observations
MIRPP1_NO_BAT_CONST	Removing the storage constraint accelerated 800 MW of 4-hour battery storage in 2034 and 2035 and 3,400 MW of LDES was added in 2037. The increased storage additions deferred CCGTs from 2032 to 2043 and 2044. Although portfolio costs were lower, unserved energy was observed.
MIRPP1_STORAGE_LOW_COST	Lower storage costs accelerated 4-hour battery storage to 2035 and 2036, displacing some LDES capacity relative to the base. Other resource selections were

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Sensitivity	Key Observations
	consistent with the MIRPP1_BASE.
MIRPP1_NO_COMP_AIR	Excluding compressed air storage from the optimization resulted in 1,700 MW of 4-hour battery storage being selected in 2037. No alternative LDES technologies were selected.

- DSM –

Sensitivity	Key Observations
MIRPP1_DSM	Additional DSM resources changed the resource mix in the 2040s. The CCGT additions in that timeframe were replaced with H_2 CTs. Other resource additions remained consistent with the MIRPP1_BASE.
MIRPP1_VPPS	Allowing VPPs into the optimization displaced a H_2 CT in the 2040s. Other resource additions remained consistent with the MIRPP1_BASE.

While these portfolios resulted in lower NPVRRs, the higher levels of DR resulted in higher energy purchases reflecting greater reliance on the energy market.

- High Costs –

Sensitivity	Key Observations
MIRPP1_CCGT_HI_COST_10p	Higher CCGT costs delayed the selection of the CCGTs from 2032 to 2044. In 2033, approximately 600 MW of LDES and 100 MW of 4-hour battery storage was selected. Although the portfolio costs were lower, unserved energy was observed.

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Sensitivity	Key Observations
MIRPP1_HI_GAS	Although higher CCGT costs were included, the resource portfolio remained mostly consistent with MIRPP1_BASE. The higher costs drove the replacement of the 2044 CCGTs to H_2 CTs.
MIRPP1_EPU_HI_COST	Higher EPU costs delayed the selection from 2036 to 2042. Other resource additions remained consistent with the MIRPP1_BASE.

Q101. What is the least-cost portfolio of the MIRPP1 Scenario?

A101. The least-cost portfolio in the MIRPP1 Scenario is the MIRPP1_NON_DISPATCH sensitivity, which is $6,198 million less than the MIRPP1_BASE. This outcome is driven by the increase in DSM resources selected in this sensitivity, which reduces the need for additional resources relative to the base. However, as mentioned previously, unserved energy is observed and there is a significant increase in energy market purchases.

Q102. What were the results of the MIRPP2 Scenario?

A102. The results of the MIRPP2 Scenario are shown below

Table 7 MIRPP2 Scenario Sensitivity Results

Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
Starting Point	MIRPP2_BASE	Base Case / Starting Point	-
Retirements	MIRPP2_RET_MNR_30	Retire Monroe U1&2 12/31/2030	$313
	MIRPP2_GRNW_45	Retire Greenwood 12/31/2045	$942
Resource Alternatives	MIRPP2_NON_DISPATCH	Dispatchable resources are not selectable	($6,965)

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Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
	MIRPP2_NO_H2_CT	Hydrogen fired CTs are not selectable	($439)
	MIRPP2_LDES_2032	LDES resources are fixed into the portfolio in 2032	$668
	MIRPP2_NO_BUILD	Energy and capacity purchases only	$867
	MIRPP2_SMR_34	SMR resources are fixed into the portfolio in 2034	$2,587
Load	MIRPP2_LOW_LOAD	Lower load due to slower EV and electrification growth	($3,387)
	MIRPP2_ATYPICAL_WEATHER	Atypical weather conditions	($1,235)
	MIRPP2_CHOICE_RETURN	Limited electric choice customer migration	$2,399
	MIRPP2_HI_LOAD	Load growth rate by at least a factor of two above base	$3,413
	MIRPP2_LOW_DC_90P_RENEW	90 percent of the incremental data center load is served by renewables	$9,344
	MIRPP2_LOW_DC	Incremental 2.0 GW of large load customer added	$9,901
	MIRPP2_LOW_DC_LOW_PURCHASE	Limited energy purchases available on the LOW_DC sensitivity	$13,878
	MIRPP2_MEDIUM_DC	Incremental 5.9 GW of large load customer demand added	$38,619
	MIRPP2_HIGH_DC	Incremental 9.3 GW of large load customer demand added	$57,203
Renewables	MIRPP2_PTC_RETURN	PTCs are reinstated beginning in 2030 for wind and solar resources	($2,572)
	MIRPP2_RENEW_REDUCTION	Limited ability to procure or construct 20 percent of renewables in Michigan	($292)
	MIRPP2_BIOMASS_PPA_5YR	Fixed in a 5-year biomass PPA	$484
	MIRPP2_BIOMASS_PPA	Fixed in a long-term biomass PPA	$661
	MIRPP2_WIND_550	550 MW of wind fixed into the portfolio every year	$2,159
	MIRPP2_DISTRIBUTION_SOLAR	10 percent of incremental solar is distribution connected front of meter	$85
	MIRPP2_LAND_RENEW_CAPPED	Land based renewables capped at 60%, CES met through other clean energy resources	$6,770
	MIRPP2_3X_RENEW_STORAGE	Tripled the amount of storage selected in the base	$8,240
Storage	MIRPP2_NO_BAT_CONST	Removed storage constraints	($3,264)

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Theme	Sensitivity Name	Description	NPV Rev Req Delta ($M)
	MIRPP2_STORAGE_LOW_COST	Lowered storage costs by 50 percent	($1,884)
	MIRPP2_NO_COMP_AIR	Limited compressed air storage from being selected in the optimization	($750)
EWR	MIRPP2_EWR_OPT	EWR selectable and optimized between the seven available programs	($4,899)
	MIRPP2_2_5_EWR	The 2.50% EWR program was fixed into the portfolio	($2,642)
	MIRPP2_2_17_EWR	The 2.17% EWR program was fixed into the portfolio	($2,446)
DSM	MIRPP2_DSM	DR programs and CVR/VVO are selectable	($1,034)
	MIRPP2_VPPS	VPPs are selectable	($30)
High Costs	MIRPP2_CCGT_HI_COST_10p	Increased the cost of the CCGT by 10 percent	$638
	MIRPP2_EPU_HI_COST	EPU costs doubled	$472
	MIRPP2_HI_GAS	Gas prices reflect the EIA high scenario	$833

Q103. Are there any key observations taken from the MIRPP2 Scenario sensitivities?

A103. Yes. Similar to the Reference and MIRPP1 Scenarios, the majority of the resource portfolios developed under the MIRPP2 Scenario include the Michigan Power Cogeneration plant in 2030, approximately 1,400 MW of CCGT in 2032 (with CCS installed in 2035), the EPU in 2036, approximately 1,700 MW of LDES in 2037, and either an additional 1,300 MW CCGT in 2044 or more than 1,000 MW of hydrogen fueled CTs during that same timeframe. As mentioned previously, the hydrogen fueled CTs are mainly selected to provide capacity and do not generate, producing no energy in the model. Additionally, most sensitivities do not result in the selection of renewable resources beyond those included in the plan to meet RPS requirements. The consistent selection of the resources across multiple scenarios

and sensitivities suggest they are cost effective and provide value under a wide range of assumptions.

Q104. Can you provide more details on the sensitivities that were run on MIRPP2 Scenario?

A104. Yes. The other sensitivity observations are detailed below:

- Retirements –

Sensitivity	**Key Observations**
MIRPP2_RET_MNR_30	Early retirement of Monroe Units 1 and 2 is not economic. The model selects 100 MW of 4-hour batteries in 2031 but the portfolio experiences unserved energy and relied on capacity purchases.
MIRPP2_GRNW_45	Early retirement of Greenwood resulted in higher portfolio costs in comparison to maintaining it through the study period, model selects approximately 700 MW of H_2 CTs to replace the plant.

- Resource Alternatives –

Sensitivity	**Key Observations**
MIRPP2_NON_DISPATCH	Excluding dispatchable resources resulted in a resource portfolio that relied heavily on energy market purchases and unserved energy was observed.
MIRPP2_NO_H2_CT	Excluding H_2 CTs from the optimization resulted in the selection of approximately 1,300 MW of CCGTs in 2043 resulting in a lower cost portfolio.
MIRPP2_LDES_2032	Accelerating LDES additions to 2032 increased the portfolio costs and did not eliminate the need for CCGT additions during that timeframe.

Line
No.

Sensitivity	Key Observations
MIRPP2_NO_BUILD	Significant unserved energy and capacity across multiple seasons and years, indicating that replacement resources are necessary to meet customer demand and maintain system reliability.
MIRPP2_SMR_34	Higher portfolio costs driven by SMR additions in 2034. Observed unserved energy in 2033 due to the absence of resource additions in that year.

- Load –

Sensitivity	Key Observations
MIRPP2_LOW_LOAD	Lower load growth resulted in fewer capacity additions, including approximately 1,400 MW of H_2 CT additions relative to the MIRPP2_BASE in the 2040s.
MIRPP2_ATYPICAL_ WEATHER	Increased weather driven variability resulted in the addition of 4-hour battery storage in 2035 and lower LDES additions in 2037.
MIRPP2_CHOICE_RETURN	Reduced choice customer migration modeled resulted in additional H_2 CT builds in the 2040s and higher energy purchases resulting in a higher cost portfolio.
MIRPP2_HI_LOAD	Higher load growth accelerated 100 MW of 4-hour battery storage to 2037 and added approximately 1,300 MW of CCGTs in 2044.
MIRPP2_LOW_DC_90P_RENEW	Fixing in renewables and storage to serve increased large load customer demand lowered the portfolio costs relative to the MIRPP2_LOW_DC. These resources displaced the 2032 CCGT additions and avoided more than 1,800 MW of H_2 CT additions in the 2040s.

Line
No.

Sensitivity	Key Observations
MIRPP2_LOW_DC	Increased large load customer growth required additional resources including a shift of 900 MW of 4-hour battery storage into 2033 and 2034. In 2044, approximately 1,300 MW of CCGTs were added, displacing more than 1,800 MW of H_2 CTs.
MIRPP2_LOW_DC_LOW_PURCHASE	Lower energy market availability drives the selection of additional CCGTs in 2032. It also causes other generation fleet to increase operations, increasing portfolio costs.
MIRPP2_MEDIUM_DC	Higher large load customer demand required additional resources including DSM, renewables, CCGTs and H_2 CTs.
MIRPP2_HIGH_DC	

In the atypical weather sensitivity, the optimization shifted between storage technologies. Specifically, the portfolio resulted in 900 MW of 4-hour batteries in 2035 and approximately 800 MW of LDES in 2037. The atypical weather portfolio also included nearly 1,400 MW of hydrogen fueled CTs in 2044 and approximately 1,300 MW of CCGTs with CCS in 2046.

- Renewables

Sensitivity	Key Observations
MIRPP2_PTC_RETURN	The modeled potential reinstatement of renewable tax credits reduced the portfolio costs, however, the resource portfolio remained mostly unchanged throughout the study period. No additional renewable resources were selected until

Line
No.

Sensitivity	Key Observations
	2046, when approximately 6,300 MW of wind was added.
MIRPP2_RENEW_REDUCTION	Higher capacity factors of out-of-state renewable resources reduced the portfolio costs. However, this analysis does not capture or quantify the additional procurement and operational risk associated with out-of-state resources.
MIRPP2_BIOMASS_PPA_5YR	Higher portfolio costs resulted from additional biomass resources with CCS in the 2040s, displacing H_2 CT additions during that period.
MIRPP2_BIOMASS_PPA_20YR	
MIRPP2_WIND_550	Annual wind addition reduced the need for approximately 1,400 MW of H_2 CT additions in the 2040s.
MIRPP2_DISTRIBUTION_SOLAR	Modeling 10 percent of renewable additions as front of meter distribution connected solar resulting in an unchanged resource portfolio from the MIRPP2_BASE with modest increases in costs.
MIRPP2_LAND_RENEW_CAPPED	Limiting options to clean energy and non-land-based renewables resulted in additional CCGTs in 2032 and approximately 2,400 MW of SMRs in the 2040s.

In MIRPP2_RENEW_REDUCTION where 20% of the planned renewable additions were assumed to be located outside of Michigan, the overall portfolio costs decreased. The lower costs were primarily driven by higher capacity factor out of state renewable resources, which reduced the energy market purchases within the portfolio. While this sensitivity assumed the generation from these resources could be delivered without limitation, there

Line No.

are potential risks associated with over relying on out-of-state resources including weather variability, transmission congestion and curtailment. All these risk factors could impact the ability of that energy to transfer into Michigan.

MIRPP2_LAND_RENEW_CAPPED resulted in higher portfolio costs as it selected approximately 2,700 MW of CCGT with CCS in 2032 and 2,400 MW of SMRs in the 2040s. The optimization did not select the other renewable resources available, such as offshore wind, as the land-based resources were considered capped as described in the MIRPP.

- Storage –

Sensitivity	**Key Observations**
MIRPP2_NO_BAT_CONST	The removal of storage constraints resulted in heavy reliance on energy market purchases but delays the selection of CCGTs until the 2040s. There was unserved energy observed.
MIRPP2_STORAGE_LOW_COST	Lower storage costs shifted the resource selection toward 6-hour battery storage and away from LDES resources. Due to reduced storage costs, the portfolio resulted in a lower cost portfolio.
MIRPP2_NO_COMP_AIR	Without compressed air storage as an option in the optimization, more 4-hour battery storage was selected. No other LDES technologies were included in the portfolio.

Line No.

The storage sensitivities generally result in lower NPVRRs relative to the MIRPP2_BASE.

In MIRPP2_NO_BAT_CONST the resource portfolio heavily relies on storage and delays the addition of CCGT with CCS resources until 2043 and 2044 with approximately 2,600 MW selected at that time. Under this sensitivity, 800 MW of 4-hour batteries are selected in 2032 followed by an additional 500 MW through the next five years. The portfolio also includes more than 2,300 MW of LDES in 2037. Although this portfolio results in lower cost, it also includes unserved energy and increased reliance on energy market purchases.

In MIRPP2_STORAGE_LOW_COST, for storage, LDES resources are not selected and the portfolio shifts to 6-hour batteries including a significant addition of 1,700 MW by 2037.

- EWR –

Sensitivity	**Key Observations**
MIRPP2_EWR_OPT	Of all the seven EWR levels provided by Witness Kupser and described in Part V of my testimony, the maximum with 50% incremental cost was selected. As a result, the 2032 CCGT additions were deferred to 2044 while 600 MW of 4-hour battery storage was added in 2033, however unserved energy was observed.

Line
No.

Sensitivity	Key Observations
MIRPP2_2_17_EWR	The higher EWR savings level resulted in a displacement of CCGT additions, however over 1,600 MW of H_2 CTs were added in the 2040s. Approximately 200 MW of storage resources were added in 2033, however, there was unserved energy observed and greater reliance on energy market purchases.
MIRPP2_2_50_EWR	The resource portfolio results were similar to the MIRPP2_2_17_EWR sensitivity, however, selects approximately 1,400 MW of H2 CTs in the 2040s.

Both EWR sensitivities resulted in lower NPVRRs relative to the base, mainly driven by the avoidance of the CCGTs with CCS in the portfolios. While the higher EWR savings levels reduced the NPVRRs, both sensitivities included unserved energy and relied heavily on energy market purchases throughout the study period.

- DSM –

Sensitivity	Key Observations
MIRPP2_DSM	The inclusion of DSM options reduced the H_2 CT additions to 900 MW in the 2040s, lowering the portfolio costs.
MIRPP2_VPPS	The inclusion of VPP resources resulted in slightly lower portfolio costs than the MIRPP2_BASE. The resource portfolio remained mostly unchanged with the exception of approximately 200 MW less H_2 CT additions in the 2040s.

- High Costs –

Sensitivity	Key Observations
MIRPP2_CCGT_HI_COST_10p	Both resulting resource portfolios were consistent with MIRPP2_BASE. Due to higher costs with natural gas prices and cost of CCGT being explored in the sensitivities, the portfolio costs were higher.
MIRPP2_HI_GAS	
MIRPP2_EPU_HI_COST	Although the EPU costs were doubled, the resource continued to be selected in the optimization. However, timing of the resource was delayed from 2036 to 2040.

Q105. What is the least-cost portfolio of the MIRPP2 Scenario?

A105. The least-cost portfolio in the MIRPP2 Scenario is the MIRPP2_NON_DISPATCH sensitivity, which is $6,965 million less than the base. This outcome is driven by the increase in DSM resources selected in this sensitivity, which reduces the need for additional resources relative to the MIRPP2_BASE. However, as mentioned previously, unserved energy is observed and there is a significant increase in energy market purchases.

Q106. Can you summarize the least-cost portfolios across the scenarios and sensitivities?

A106. Yes. Across each scenario, the least cost portfolio was the one resulting from the non-dispatchable sensitivity. While this portfolio produced the lowest NPVRR, it failed to provide an adequate balance between cost, reliability and performance. Specifically, the portfolio resulted in unserved energy, high reliance on energy market purchases, and lower resource diversity.

Q107. After the least-cost portfolios are determined, what is the next step in the IRP process?

A107. After analyzing the EnCompass model results and identifying the least-cost portfolios, the Company performed additional evaluations consistent with the IRP filing requirements. The least-cost portfolios, along with other portfolios, were advanced for further assessment through a series of risk analyses designed to evaluate the portfolio performance under a range of future uncertainties. These risk analyses provide additional insight into how the portfolios perform beyond the capacity expansion modeling and discussed in more detail in Part VIII of my testimony.

PART VIII: Synthesis of results and Risk Assessment

Q108. How was the preliminary PCA developed and evaluated?

A108. The preliminary PCA was developed through a comprehensive synthesis or review of results from the Company's scenario and sensitivity analyses (also considered part of the risk assessment explained later in this part of my testimony). The preliminary PCA incorporates favorable elements observed across the resultant portfolios. The Company did not assume the preliminary PCA was preferred without further evaluation. The preliminary PCA was evaluated alongside other selected portfolios within the full risk assessment framework. Through this process, the Company confirmed that the preliminary PCA performs competitively across the various aspects tested including cost, reliability, and exposure to uncertainty, supporting its identification as a reasonable and prudent portfolio for further consideration.

Q109. Did the Company evaluate the preliminary PCA and alternative resource portfolios on a consistent and reasoned basis?

A109. Yes. In developing the preliminary PCA, the Company conducted capacity expansion and production cost modeling across the scenarios and sensitivities described in my testimony. That modeling produced a range of portfolios reflecting different resource combinations, operating characteristics, and planning assumptions. The Company reviewed and compared those portfolios using the applicable assumptions and evaluation criteria for each scenario and stage of the IRP process.

The Company's evaluation included the applicable load forecasts, planning requirements, resource assumptions, clean energy requirements, and methods for evaluating cost, reliability, and other portfolio attributes described in my testimony. The Company also considered whether the resources included in the portfolios under consideration could reasonably be developed in the required timeframe and whether each portfolio would provide the capacity, energy, resource adequacy, and other system attributes needed to serve customers.

The evaluation considered portfolio cost, resource diversity, emissions and other available environmental information, and the operating characteristics of the resources included in each portfolio. Based on those modeling results and comparisons, the Company narrowed the portfolios and developed a preliminary PCA. As described later in my testimony, the Company then subjected the preliminary PCA and selected alternative portfolios to additional analyses, including resource adequacy, risk, environmental justice, financial, and

transmission analyses. The Company considered these modeling and analytical results collectively in confirming the final PCA.

Q110. Why is risk assessment important in the IRP process?

A110. Risk assessment is an important component of the IRP process as it ensures that the PCA represents the most reasonable and prudent plan considering the uncertainty of the future. The energy industry is continuously evolving with dynamic market conditions, technology advancements, changing regulatory requirements and operational risks. There is no single set of assumptions that can fully capture future conditions. Risk assessment addresses this uncertainty by evaluating performances of potential portfolios across a wide range of different futures. This process supports the identification and verification of a portfolio that is not only cost-effective under normal conditions, but also flexible and reliable under various levels of future uncertainty.

Q111. What are the filing requirements for a utility IRP related to risk assessment?

A111. The IRP filing requirements were established in Case Nos. U-21867 and U-21570 and require utilities to include a robust risk assessment as part of the IRP filing. Specifically, it states "[a]cceptable forms of risk assessment include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent-based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation."[13]

[13] MPSC, Order in Case Nos. U-21570 and U-21867, December 18, 2025, pp 6-7.

Q112. Which form(s) of risk assessment did the Company perform?

A112. The five forms of risk assessment the Company conducted were:

1. Scenario analysis
2. Global sensitivity analysis
3. Portfolio metric evaluation
4. Stochastic economic risk analysis
5. Stochastic reliability analysis (resource adequacy)

Q113. Why did the Company choose to perform these IRP risk assessment approaches?

A113. The Company selected the five risk assessment approaches to ensure compliance with the filing requirements, alignment with industry best practices, and continuity with prior risk assessment efforts. Scenario and global sensitivity analyses, discussed in Part V of my testimony, are foundational in the development of an IRP and are explicitly required by the filing requirements and MIRPP. The portfolio metric evaluation builds upon the methodology used in the Company's 2022 IRP (Case No. U-21193) with refinements to enhance the transparency and quantitative approach and evaluates the performance of all portfolios across a defined set of key metrics. The Company also incorporated stochastic analysis as a best-in-class approach to assessing uncertainty based on benchmarking other utility IRPs and the Company's prior experience applying stochastic methods in IRP and Certificate of Necessity proceedings. There were two forms of stochastic analyses performed: (1) an economic stochastic risk analysis, which evaluates variability in portfolio costs, and (2) a resource adequacy risk analysis, which tests system performance under uncertain operating and external conditions.

Q114. How does the Company's risk assessment structure evaluate and refine the resource portfolios?

A114. The Company's risk assessment structure connects all the five approaches to each other. Scenario and sensitivity analyses were conducted initially producing a varying set of resultant portfolios (see Part VII of my testimony for detailed results, including the NPVRR outcomes). Each portfolio was then evaluated using the portfolio metric approach, which assesses performance across the six key metrics identified in Part II of my testimony. Based on this evaluation, portfolios were selected for further analyses based on the overall weighted portfolio metric scores in addition to the least cost portfolios under each scenario. These selected portfolios were then evaluated through both stochastic economic and stochastic reliability analyses.

Portfolio metric evaluation

Q115. What portfolio evaluation metrics were used to assess and compare resource portfolios across sensitivity analyses?

A115. To evaluate and compare resource portfolios across sensitivities, an evaluation framework was developed using several key metrics including:

1. **Cost differentials.** A "delta" (change) analysis was performed comparing both the annual and net present value revenue requirement between the sensitivity and the base portfolio. Within each scenario, the resultant sensitivities' revenue requirements were ranked lowest to highest to highlight the least cost portfolio outcomes.

Line No.

2. **Environmental.** As part of the EJ incorporation into the analysis, CO_2 tons emitted were evaluated to confirm alignment with the Company's target of a 90% reduction in carbon emissions by 2040. Within each scenario, the resultant sensitivities' 2040 CO_2 emission reductions were ranked highest to lowest.

3. **Reliability and capacity adequacy.** Reliability and capacity were assessed using the MISO PRMR standard by reviewing the resulting reserve margins in 2040. This evaluation measured if portfolios maintained an appropriate balance of capacity, avoiding both under-building and over-building of resources. In addition, the reliability of the resource portfolio was evaluated by reviewing instances of unserved energy, which indicate periods when available resources could not meet customer demand. Together, these metrics provide insight into the reliability of each portfolio.

4. **Market exposure and risk.** Market risk was evaluated by reviewing average energy market purchases to assess whether a given portfolio exhibited a higher reliance on market energy purchases to meet customer demand.

5. **Flexibility and integration.** System flexibility was evaluated by examining renewable curtailment expressed as a percentage of total renewable capacity. This metric provided insight into how effectively renewable generation was integrated with storage.

6. **Resource diversity.** Resource diversity was quantified using the Shannon Index applied to the portfolio mix, providing a measure of the balance and

Line No.

concentration of resource types within each portfolio. The Shannon Index is used to measure the diversity of generation resources in different portfolios. This helps present a comparison between the relative risks associated with greater concentrations of resources in singular categories. It emphasizes variety and balance, while giving greater weight to the existence of small contributors, when compared to other diversity metrics. The Shannon Index is given by:

$$H = -\Sigma\, p_i \ln(p_i)$$

The "p" represents the share of generation from technology "I". A higher entropy value (H) indicates greater diversity and lower concentration risk, and a lower entropy value indicates lower diversity and higher concentration risk.[14]

Q116. How were the six metrics considered in the portfolio metric evaluation?

A116. Each portfolio resulting from the sensitivity analysis was evaluated across the six metrics discussed above. For each metric category, the portfolios were assigned a score based on their performance and the scores were combined using a weighted evaluation structure to develop an overall portfolio score.

The weighting structure was intentionally designed to reflect the Company's planning objectives and stakeholder feedback discussed by Witness Hajj. Reliability and costs received the greatest weighting reflecting the importance of maintaining reliable electric service and affordability for customers while also considering a broader set of planning objectives. The remaining metrics were

[14] Quantifying Diversity of Electricity Generation in the U.S., https://energy.utexas.edu/sites/default/files/UTAustin_FCe_Quantifying_Diversity_2018_Feb.pdf, accessed on September 4, 2026.

weighted evenly, with the exception of integration and flexibility, which received a lower weighing.

The evaluation was not intended to identify a single preferred portfolio but to provide a framework to compare portfolios across identified metrics. The team reviewed the portfolio performance across all the metrics and considered the weighted results collectively. Generally, resources associated with portfolios that achieved stronger overall performance than the base portfolio were identified and considered for inclusion in the preliminary PCA.

Q117. How was the preliminary PCA developed from the portfolio metric evaluation results?

A117. The portfolio metric evaluation results were reviewed, and portfolios were identified that performed better than the base portfolio in terms of the total weighted score. Generally, resources associated with portfolios that demonstrated higher performance over the various categories were incorporated into the preliminary PCA. For example, the sensitivity that included VPPs resulted in lower NPVRRs and improved resource diversity relative to the base portfolio. As a result, those resources were included in the preliminary PCA.

Q118. What was the resultant preliminary PCA?

A118. The preliminary PCA is built upon the starting point planning resources and includes the incremental capacity additions shown in Table 8 below:

Table 8 Preliminary PCA Incremental Capacity Additions

Resource Type	Model Year	Capacity Added Nameplate (MW)
CVR/VVO	2027-2036	17
VPPs	2028-2046	73
Cogen	2030	138
Solar	2031-2036	5,600
Wind	2031-2035	750
CCGT w/CCS	2032, 2044	2,694
EPU	2036	177
4-Hr Lithium Ion	2037	100
Compressed Air	2037	1,591
H_2 fueled CT	2040,2041	466
Total Capacity Added 2027-2046		**11,606**

Q119. What is a stochastic analysis?

A119. A stochastic analysis is an advanced modeling technique that incorporates uncertainty by assigning probability distributions to key input variables. Building upon the deterministic set of assumptions, stochastic analysis or modeling is performed repetitively from hundreds to thousands of times, with each iteration drawing different values from these distributions. Each iteration is referred to as a "draw." This process produces a distribution of possible outcomes, creating a more robust understanding of potential variability and risk. Applying the stochastic analysis to evaluate both economic outcomes and system reliability provides insight into the likelihood and range of potential performance under uncertain future conditions.

Line No.

Q120. How were the portfolios selected for the inclusion in the stochastic analyses?

A120. The portfolios included in the stochastic analyses were selected primarily based on the IRP filing requirements. As noted in the IRP filing requirements, a comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios, the proposed resource plan, and any alternative resource plans presented by the utility[15]. Consistent with this guidance, the least cost portfolios from each scenario and the Company's preliminary PCA were selected for the stochastic analyses. The preliminary PCA was the Company's proposed resource plan at that stage of the IRP process and was subsequently refined based on the stochastic analyses and other evaluations described later in my testimony.

Additional portfolios were evaluated to meet the commitments made in Case No. U-21193, 2022 Settlement Agreement, including sensitivities related to Monroe replacement options. Other portfolios were selected as exploratory tests based on observations from the initial capacity expansion modeling results. Lastly, the Company modeled a "no-build" portfolio specified in the CON requirements. Although, the "no-build" portfolio was not explicitly required for the risk assessment or resource adequacy analysis, it was selected as a bookend to further evaluate the implications of that alternative. The portfolios included in the stochastic risk analyses are identified in Table 9 below:

[15] Page 18 of the December 18, 2025 order in Case Nos. U-21570 and U-21867

Line No.

Table 9 List of portfolios selected for stochastic risk analyses

No.	Case Name
1	REF26_BASE
2	REF26_NON_DISPATCH[16]
3	REF26_NO_BAT_CONST
4	REF26_NO_BUILD
5	REF26_PRELIM_PCA

Stochastic economic risk analysis

Q121. Can you describe the stochastic economic risk analysis?

A121. The stochastic economic risk analysis was conducted using the EnCompass model and applied to the selected portfolios identified in Table 9 above. This analysis evaluates the variability of portfolio costs under uncertain market, fuel price, and operational conditions. Additional detail regarding the methodology and results of this analysis is provided in the testimony of Witness Busse. These same portfolios were evaluated in stochastic reliability analysis as well.

Q122. How were the results of the stochastic economic risk analysis used?

A122. As Witness Busse explains in his testimony, the stochastic economic risk analysis results provided additional insights into how the cost of each portfolio varied based on the varied conditions and assumptions explored. The preliminary PCA performed well across the varied assumptions, demonstrating that it is a balanced set of resources that performs reliably and manages risk. Overall, the analysis

[16] The NON_DISPATCH sensitivity was the least cost portfolio across the three scenarios. Included the REF26_NON_DISPATCH in the risk analyses as the representative portfolio.

supports the preliminary PCA as a prudent portfolio for consideration under this IRP.

Stochastic reliability analysis

Q123. What is the purpose of the stochastic reliability analysis and how was it performed?

A123. The stochastic reliability (i.e., resource adequacy) analysis was performed by PowerGEM. As discussed by Witness Brooks, this analysis evaluates the selected portfolios' ability to reliably meet hourly customer demand under a range of uncertain conditions, including variability in load, resource availability, and weather. The same set of portfolios evaluated in the stochastic economic analysis was used in this assessment to ensure consistent and comprehensive evaluation of both cost and reliability risks.

Q124. How were the results of the stochastic reliability or resource adequacy analysis considered in the risk assessment process?

A124. The resource adequacy analysis performed by PowerGEM evaluated each portfolio's ability to meet resource adequacy standards in 2029 and 2033 study years using the MISO requirement of 0.1 LOLE as explained in Part I of my testimony. Each of the five portfolios identified in Table 9 were analyzed under a wide range of varying operating conditions to assess the probability of unserved energy periods occurring. While the preliminary PCA was the primary focus of the analysis and demonstrated the strongest reliability performance, the results of the other portfolios provided additional insight into how different resource mixes affected reliability outcomes. The results were considered as the Company refined

the portfolio and confirmed that the final PCA ensured a balance of reliability, affordability and portfolio diversity.

Q125. Why was there a focus on 2029 and 2033 in the resource adequacy analysis?

A125. The resource adequacy analysis focused on 2029 and 2033 as study years because they align with the significant transition periods in the generation fleet due to the planned retirement of the Monroe Power Plant. Two Monroe units are planned to retire at the end of 2028 and the remaining two units planned to retire at the end of 2032. By evaluating resource adequacy following these major fleet transitions, the effectiveness of the replacement resources selected in the capacity expansion model would identify reliability risks and concerns associated with each of the portfolios assessed.

Q126. What were the results of the resource adequacy analysis for the five portfolios evaluated?

A126. Table 10 below summarizes the resource adequacy analysis results for each portfolio in the 2029 and 2033 study years based on the MISO 0.1 LOLE planning standard. If the portfolio achieved a LOLE of 0.1 or lower, it is identified as "Pass" below and if the LOLE was greater than 0.1, the portfolio was identified as "Fail." As shown below, all portfolios satisfied the LOLE standard in 2029 but failed to meet the 0.1 standard in the 2033 study year. For additional details, refer to the testimony of Witness Brooks.

Line No.

Table 10 Resource Adequacy Analysis Results

Case Name	2029 Study Year	2033 Study Year
REF26_BASE	PASS	FAIL
REF26_NON_DISPATCH	PASS	FAIL
REF26_NO_BAT_CONSTRAINT	PASS	FAIL
REF26_NO_BUILD	PASS	FAIL
REF26_PRELIM_PCA	PASS	FAIL

Q127. How did the preliminary PCA perform relative to the other portfolios evaluated?

A127. Although none of the portfolios achieved the MISO 0.1 LOLE standard in the 2033 study year, the preliminary PCA demonstrated the strongest resource adequacy performance among the portfolios evaluated. The results indicate that the preliminary PCA was closer to achieving the 0.1 LOLE standard than the other alternative portfolios, potentially requiring the least incremental capacity to close the resource adequacy gap as detailed in the testimony of Witness Brooks. This also indicates that portfolios containing higher levels of dispatchable and flexible capacity exhibited better reliability performance.

Q128. What considerations were made given that the preliminary PCA did not meet the standard in 2033?

A128. Since the preliminary PCA did not fully satisfy the 0.1 LOLE standard in 2033, additional analysis was performed to determine the amount of incremental capacity required to reach the standard. PowerGEM performed an analysis that identified how much "perfect capacity" was needed for the portfolio to achieve a 0.1 LOLE.

As Witness Brooks explains in his testimony, perfect capacity is a hypothetical resource with 100 percent availability and no outage risk that is used as a communication tool. This analysis determined that approximately 600 MW of perfect capacity would be needed for the preliminary PCA to achieve the resource adequacy standard.

Q129. How was the identified capacity need addressed?

A129. After identifying the approximately 600 MW of additional capacity needed to meet the resource adequacy standard, the Company considered several approaches to address the need while remaining generally consistent with the preliminary PCA. A range of factors considered include market availability, energy market risk, portfolio diversity, and operational characteristics. Based on these considerations and discussed further below, it was determined that accelerating the addition of a 1x1 CCGT from its originally projected in-service date in 2044 to 2033 represented the most prudent approach to address the identified resource adequacy need.

Q130. Did the Company consider LDES to meet the identified capacity need?

A130. Yes. When evaluating alternatives to address the identified capacity need, LDES, specifically compressed air energy storage, was considered as a potential option to address this need. While compressed air energy storage was selected in the preliminary PCA, it was not selected until a later point in the study period. As explained by Witnesses Pratt and Schroeder, the Company had not received bids from LDES developers through its recent RFP processes, indicating limited market availability within the timeframe needed to address the resource adequacy gap. In addition, while there are several LDES technologies under development, they are

currently being deployed at limited scale. Based on these considerations, compressed air energy storage was not identified as a prudent option to meet the resource adequacy need in 2033.

Q131. What did the capacity expansion modeling indicate regarding the accelerated deployment of LDES?

A131. As noted across the capacity expansion modeled sensitivities as discussed in Part VII, the optimization generally did not economically select LDES technologies other than compressed air energy storage. Even when compressed air energy storage was selected, it was, as noted above, not selected until 2037, indicating that the model did not identify an economic need for this technology earlier in the study period. Additionally, a sensitivity was evaluated that accelerated compressed air storage into 2032. Under the Reference Scenario, that sensitivity resulted in an increased NPVRR of approximately $655 million relative to the REF26_BASE. This indicates that accelerating compressed air energy storage would not be a cost-effective approach. While compressed air energy storage and other LDES technologies remain potential future resource options, the modeling results did not support them as a near-term solution for the identified capacity need.

Q132. How did the Company evaluate energy market risk to meet the identified capacity need?

A132. Reducing energy market risk was an important consideration in determining the resources needed to meet the identified capacity need. It is not prudent to rely on energy market purchases to satisfy customer demand, especially during periods of high system demand and stress. During tight market conditions, the availability of

energy imports may be constrained, and if there is availability, the market prices could be significantly higher. As demonstrated in the capacity expansion sensitivities presented in Part VII, portfolios that included larger amounts of 4-hour storage generally had greater reliance on the energy market to serve load. The CCGT acceleration option provides additional dispatchable generation capabilities and energy production, reducing the reliance on market purchases and providing protection against market price volatility.

Q133. How was portfolio diversity considered?

A133. Portfolio diversity was also an important consideration in selecting the resources needed to fill the resource adequacy gap. By 2030, the Company expects to have approximately 3,000 MW of 4-hour lithium-ion batteries online. When combined with the approximately 1,100 MW of storage provided by Ludington, the Company will already have more than 4,000 MW of storage resources within its fleet. Relative to the projected 2033 peak demand of approximately 12,000 MW, these storage resources represent roughly one third of the expected peak load. While energy storage will continue to play an important role in the Company's portfolio mix, an overreliance on a resource that cannot produce energy and can only discharge four hours during a day can increase operational risk. A more balanced portfolio that complements storage and incorporates additional dispatchable generation provides a more balanced resource mix and reduces dependence on a single resource type to meet customer needs.

Q134. How were operational characteristics considered?

A134. Operational characteristics were an important consideration in the evaluation of alternatives to address the identified resource adequacy need. The retirement of the Monroe Power Plant represents a loss of over 3,000 MW of dispatchable baseload generation that has historically provided reliable, available energy throughout the years to serve customer demand. As the Company transitions to a cleaner generation portfolio, it is important to consider the ability of the system to produce energy during extended periods of high load, low renewable generation output, or a combination of both. Unlike thermal generation resources, 4-hour lithium-ion batteries do not produce energy, instead storing energy generated from other resources and shifting that energy to periods when it is needed or economical to do so. Because of this, energy storage is dependent upon having energy available for charging.

In contrast, a CCGT resource provides operational capabilities that are materially different from storage and other limited-duration resources. Because a CCGT produces energy, is dispatchable, and can be operated for sustained periods of time, it can serve customer load during extended conditions when storage resources may be constrained by state of charge, charging-energy availability, or duration limits. The ability to produce dispatchable energy for longer periods of time becomes increasingly important as the Company retires large amounts of baseload generation and customer demand grows, especially when those customers have high load factors that require energy across all hours of the day rather than primarily in peak periods. Overall, the accelerated CCGT represents the most prudent and balanced alternative because it provides dispatchable energy and operational

flexibility to address the identified resource adequacy need to serve customers under a wide range of operating conditions.

Q135. What was the impact of adding the accelerated 1x1 CCGT on the resource adequacy results?

A135. To evaluate the impact of accelerating the 1x1 CCGT, the Company provided PowerGEM with a revised preliminary PCA that included this resource in the 2033 study year. The results demonstrated a material improvement in the reliability performance. The revised portfolio resulted in a LOLE of 0.09 (LOLE of 0.20 prior to revision), satisfying the resource adequacy standard. Additionally, the other reliability metrics evaluated by PowerGEM improved substantially. For example, the projected unserved energy hours were reduced from 141 to 53 hours. Refer to the testimony of Witness Brooks for more detail. These results demonstrate that including the additional CCGT strengthens the portfolio's ability to reliably serve customers.

Q136. Were any additional sensitivities performed for the resource adequacy analysis?

A136. Yes. In addition to the resource adequacy analysis conducted as described above, the revised preliminary PCA was evaluated under extreme weather conditions designed to test the portfolio reliability during periods of elevated system risk. Additional details regarding the methodology and results of these sensitivities are provided in the testimony of Witness Brooks. The revised preliminary PCA portfolio was evaluated under both hotter than normal and colder than normal weather conditions to better understand the impact of additional stress on the

system and resources. The results demonstrated that the revised preliminary PCA remained reliable under a range of extreme weather conditions. Reliability was more challenged under the hotter than normal than under the extreme colder than normal weather conditions. Overall, the analysis provided additional confidence that the portfolio consists of an appropriate mix of resources.

Q137. Was any additional analysis performed before finalizing the PCA?

A137. Yes. Before finalizing the PCA, additional analyses were performed including transmission impact studies conducted by ITC and EJ analyses. These analyses are discussed in more detail in the testimonies of Witnesses Djordjevic and Marietta. These studies were completed to evaluate whether the revised preliminary PCA remained a prudent plan when these additional factors were considered. As discussed further below, both analyses helped confirm that the portfolio could be reasonably implemented from a transmission standpoint while also considering potential impacts on EJ communities. The results of these evaluations provided additional support for the Company's determination that the revised preliminary PCA is appropriate to be selected as the Company's finalized PCA.

Q138. How were the transmission impact studies considered in the finalization of the PCA?

A138. ITC evaluated the revised preliminary PCA to assess potential transmission impacts associated with the projected resource additions and retirements. The transmission impact studies were considered as a key planning input in finalizing the PCA. ITC's analyses showed that the revised preliminary PCA was supported from a transmission planning perspective and produced favorable results compared to the

initial scenario analyses, including CIL performance and transmission cost impacts. The revised preliminary PCA also reflected lessons from the sensitivity studies, including the value of strategically located dispatchable generation, the benefits of planned transmission expansion, and the importance of coordinating resource additions with transmission system capability. Overall, the study results supported the revised preliminary PCA from a transmission feasibility, reliability, and cost perspective, subject to future transmission planning, generator interconnection, and other project-specific reliability studies. The Company concluded that the revised preliminary PCA remained a reasonable and prudent portfolio from a transmission perspective. For additional details regarding the studies, refer to the testimony of Witness Djordjevic.

Q139. How were the EJ analysis results considered in the finalization of the PCA?

A139. The EJ analysis considers both emission projections as well as an analysis using the EJ screening tool. As described in the IRP filing requirements, four portfolios were required to be incorporated into a comprehensive health and environmental impact analysis. It was also directed that the portfolio be run under the MIRPP1 Scenario. The portfolios include:

1. Portfolio 1: Previously approved portfolio (MIRPP1_2022_IRP_PCA)
2. Portfolio 2: Utility PCA portfolio (MIRPP1_2026_IRP_PCA)
3. Portfolio 3: Optimized portfolio in MIRPP Scenario 1 (MIRPP1_BASE)
4. Portfolio 4: Optimized portfolio in MIRPP Scenario 1 with high load sensitivity (MIRPP1_LOW_DC)

The results of the EJ analysis are further discussed by Witness Marietta in his testimony. The analysis showed that all four portfolios produce similar impact to EJ communities and comparable environmental outcomes. The revised preliminary PCA demonstrated significant emission reductions and did not result in materially different EJ impacts relative to the other portfolios evaluated. This analysis, from an environmental perspective, supports the resource plan presented in the revised preliminary PCA.

Q140. What was the resultant revised preliminary PCA and how did it compare to the preliminary PCA?

A140. The revised preliminary PCA included the following incremental resources (relative to the starting point) shown in Table 11 below and shows the preliminary PCA for comparison purposes. Throughout the remainder of this testimony, the finalized PCA is referred to as the "PCA."

Table 11 Preliminary PCA vs. Revised Preliminary PCA Incremental Capacity Additions

	Preliminary PCA		PCA (Revised Preliminary PCA)	
Resource Type	**Model Year**	**Capacity Added Nameplate (MW)**	**Model Year**	**Capacity Added Nameplate (MW)**
CVR/VVO	2027-2036	17	2027-2036	17
VPPs	2028-2046	73	2028-2046	73
Cogen	2030	138	2030	138
Solar	2031-2036	5,600	2031-2036	5,600
Wind	2031-2035	750	2031-2035	750
CCGT w/CCS	2032, 2044	2,694	2032, 2033[17]	2,061
EPU	2036	177	2036	177

[17] Resource addition start dates are modeled as January 1st of a given year. The proposed CCGT plants have commercial operation dates of 2031 and 2032 as described by Witness Hajj.

Line No.

	Preliminary PCA		PCA (Revised Preliminary PCA)	
4-Hr Lithium Ion	2037	100	-	-
Compressed Air	2037	1,591	2037	1,663
H2 fueled CT	2040,2041	466	2043-2046	1,398
Iron Air	-	-	2044	50
Total Capacity Added 2027-2046		**11,606**		**11,927**

Q141. Does the PCA comply with the CES?

A141. Yes. The PCA complies with the CES. In 2035, the total clean energy generation represents 104% of the retail sales and 106% in 2040. For more detail, see Exhibit A-2.5 Clean Energy Plan (Appendix A).

Q142. What impact does the CES or CEP have on the diversity of the Company's PCA?

A142. The CES influenced the development of the PCA by ensuring a balanced portfolio capable of complying with the clean energy requirements while maintaining reliability and resource diversity. Throughout the portfolio metric evaluation process, diversity was assessed using the Shannon Index, which measures how diverse a portfolio is based on its resource types included. Portfolios with lower diversity scores generally had greater reliance on renewable generation and storage resources. While renewables and storage still play a significant role in the Company's PCA, a portfolio heavily concentrated in a limited number of technology types, those portfolios may be more exposed to variations in weather, resource availability, and operational performance.

As noted, the PCA maintains significant investments in renewable and storage resources, with renewable resources representing 56 percent of the total projected installed nameplate capacity in 2040 and storage resources representing 18 percent. However, storage resources do not qualify as clean energy resources, increasing the need for additional clean, dispatchable resources to provide sufficient clean energy generation to support compliance with the CES.

Q143. Were the benefits of resource diversity quantified or monetized in the Company's evaluation?

A143. No. Resource diversity benefits were considered in the evaluation, but they were not directly quantified or monetized because it is difficult to isolate economic value attributable solely to resource diversity. In some instances, portfolios with lower diversity indices resulted in lower revenue requirements as they avoided investment in clean dispatchable resources. However, those portfolios often relied more heavily on market purchases to meet customer demand. High dependence on the energy market exposes customers to market price volatility, changing market conditions, and energy availability risks. By maintaining a more diverse portfolio with a broader mix of resources that can meet customer demands, the PCA can reduce reliance on the market and provide greater protection against future uncertainty. The Company believes a more diverse PCA can mitigate risk and provide economic value by providing flexibility and reducing customer exposure to potential volatile future market outcomes, which are likely with the changing energy environment, more weather dependent resources, and high load factor customer growth nationwide.

Line No.

Overall, the PCA portfolio provides a balanced and diverse resource mix that is not overly dependent on any single technology type or fuel sources. This diversity improves the Company's ability to remain flexible in changing system conditions, weather variability, market volatility, and resource performance while supporting resource adequacy needs, and compliance with Michigan's 2023 energy laws.

PART IX: 2026 IRP Proposed Course of Action

Q144. Was the PCA modeled through EnCompass?

A144. Yes. The team modeled the PCA through EnCompass under the required scenario and sensitivities. The results are displayed in Table 12. Additionally, the annual revenue requirement impact of the PCA is detailed in Exhibit A-2.3.

Table 12 PCA in Required Scenarios and Sensitivities

Scenario	Case Name	NPVRR Delta
MIRPP Scenario 1	MIRPP1_2026_PCA	-
	MIRPP1_HI_GAS_2026_PCA	$309
	MIRPP1_RENEW_REDUCTION_2026_PCA	($217)
	MIRPP1_LOW_DC_2026_PCA	$18,057
	MIRPP1_MEDIUM_DC_2026_PCA	$47,969
	MIRPP1_HIGH_DC_2026_PCA	$65,745
	MIRPP1_LAND_RENEW_CAPPED_2026_PCA	($235)
	MIRPP1_10_DG_2026_PCA	$827
	MIRPP1_15_DG_2026_PCA	$1,501
	MIRPP1_20_DG_2026_PCA	$2,288
	MIRPP1_ATYPICAL_WEATHER_2026_PCA	$271

Q145. What is the key takeaway from modeling the PCA across the required scenario and sensitivities?

A145. The key takeaway is that the PCA is a cost-effective and reliable resource portfolio that provides a balance of diverse resources capable of performing well across a wide range of future uncertainties. It is important to note that while the 2026 PCA is modeled under the MIRPP1 Scenario, it differs from the REF26 Scenario portfolio. Those differences are driven by the underlying assumptions associated with the load forecast. As described by Witness Sirwaitis, the MIRPP1 Scenario incorporates higher levels of electrification and electric vehicle adoption growth resulting in higher projected demand. To meet this increased demand, the optimized portfolios generally include additional resources compared to the PCA. This impact is particularly evident in the sensitivities that assume additional large load growth of the low, medium, and high cases described in the MIRPP1 Scenario.

Despite these base assumption differences, the 2026 PCA is a prudent portfolio that meets customer demand with a combination of diverse resources. Exhibit A-2.6 MIRPP Required Scenario and Sensitivity Capacity Credit Graphs includes a graph of all existing resources and PCA resource additions that will serve demand in each year for all planning years. Exhibit A-2.7 MIRPP Required Scenario and Sensitivity Energy Graphs includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon.

Q146. Why is the PCA the most reasonable and prudent plan?

A146. After completing the evaluations described in Steps 5 and 6, the Company reviewed the modeling results, resource adequacy analysis, risk assessment, EJ review, financial analysis, and grid reliability analysis, collectively. Based on that integrated review, the Company confirmed the PCA as the most reasonable and prudent plan because it addresses the identified capacity need, satisfies applicable PRMR, supports clean energy compliance, and balances reliability, cost, feasibility, resource diversity, and implementation risk. The PCA was not selected based solely on the lowest modeled cost in any individual scenario or sensitivity, but rather on the Company's overall assessment of portfolio performance across the full IRP record.

Q147. How did the PCA compare to the 2022 PCA?

A147. When considering a direct comparison between the PCA and the PCA approved in the 2022 IRP Settlement, it should be viewed in the context and awareness that there are significantly different assumptions underlying each resultant portfolio. Since the 2022 IRP, key inputs have materially changed including the Company's load forecast, which now includes significant growth from large load customers. In 2022, federal tax incentives for renewable resources were in place. In addition, since 2022, pricing for commodities and technology capital cost assumptions have increased. Because the 2022 PCA was optimized based on the set of assumptions that were available at the time the modeling was performed, changes to those assumptions are going to naturally result in changes to the overall resource plan.

Line No.

Resource additions between 2027 and 2029 in the 2022 IRP were updated to align with the latest assumptions and project execution status. Consistent with the 2022 PCA, the resources additions in that portfolio between 2030 and 2042 were fixed into the model. However, beyond those fixed resources, the model optimized additional resources to meet the higher projected load and associated capacity needs. As a result, the 2022 PCA optimization selected additional resources including the Michigan Power Cogeneration plant in 2030, the EPU in 2036, approximately 1,700 MW of compressed air energy storage in 2037, and over 2,300 MW of hydrogen fueled CTs in the 2040s.

Under current assumptions, the PCA results in approximately $3.5 billion lower NPVRR than the 2022 PCA. Annual revenue requirements are presented in Exhibit A-2.3, and the corresponding rate impact and energy burden analyses are discussed by Witness Machi. While EnCompass is a robust and appropriate planning tool for resource optimization and dispatch simulation, it is not designed to be a replacement for the Company's regulatory accounting treatments and rate making processes. The revenue requirements produced by the model are intended to provide a reasonable approximation of costs as an analytical basis for comparing the economic performance of other resource portfolios under a common set of assumptions. The modeled revenue requirement results should be interpreted as directional and informative estimates rather than an official mechanism for the projection of the Company's actual revenue requirement and accounting practices.

Q148. Were there sensitivities conducted to assess the PCA without the OACS and Google load additions and associated costs?

A148. Yes. The Company conducted two sensitivities that excluded the OACS and Google load additions and associated costs. The first excluded the Google load addition and associated costs, consistent with the Company's filing and commitments in pending Case No. U-22058. The second excluded both the Google and OACS load additions and associated costs, including the with-and-without analysis required by the Commission's December 18, 2025 Order in Case No. U-21990, as further discussed by Witness Hajj. These sensitivities are used by Witness Machi to develop the rate impact and energy burden analyses required as part of the IRP filing.

Q149. How were the sensitivities without the OACS and Google load additions modeled?

A149. The first sensitivity removed the projected Google load from the forecast, as provided by Witness Sirwaitis. The team also removed the resources and other planning assumptions associated with the Google load, including 400 MW of 4-hour batteries, 50 MW of 8-hour batteries, and 1,600 MW of renewables. The associated temporary resources, including the ZRC contract and DR, were also removed. In alignment with the lower load forecast, Witness Kupser provided an updated EWR forecast reflecting a 1.5% savings level without Google. The portfolio was then reoptimized in EnCompass using the lower load forecast and revised resource assumptions.

Line No.

The second sensitivity removed both Google and OACS loads, as provided by Witness Sirwaitis. In addition to the changes described for the without Google sensitivity, this sensitivity also removed approximately 1,400 MW of 4-hour batteries and 1,800 MW of renewables associated with the OACS load. Witness Kupser also provided a revised EWR forecast reflecting a 1.5% savings level without the Google and OACS loads. The portfolio was then reoptimized in EnCompass using the lower load forecast and revised resource assumptions. The resulting revenue requirements, shown in Exhibit A-2.4, were provided to Witness Machi for use in the rate impact and energy burden analyses.

Q150. Does this complete your direct testimony?

A150. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JASON T. BUSSE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JASON T. BUSSE

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Jason Busse (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company) with the position of Supervisor – Program Management in the Resource Planning and Transmission Modeling (RP&TM) group.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from the University of Toledo, with a Bachelor of Science in Civil Engineering in 2000.

Q4. What is your professional experience?

A4. I held various positions in construction management from 2000 to 2008 in the areas of project management, contract administration, and cost controls. In 2008, while working for Administration Controls Management, Inc. I was assigned to the Fermi 1 Power Plant decommissioning project as a Cost Engineer. In 2012, I transitioned to the Fermi 2 Nuclear Power Plant as a contract employee supporting the Business Operations Group. My duties included the set up and close out of capital accounts, preparing project budgets for approval and contract administration support.

In 2015, I joined DTE Electric as a Principal Financial Analyst where I was responsible for the financial close out of capital projects at the Fermi 2 Nuclear Power Plant. My duties also included budget and forecast development of capital

spend at the plant, along with refueling outage budgeting and cost controls. In 2022, I was promoted to Senior Strategist in the Integrated Resource Planning group. In this role, I supported the Company's 2022 Integrated Resource Plan (IRP) filing by preparing levelized cost of energy evaluations for potential new resources to be used in the modeling, along with contract administration of vendors used in preparing the IRP report.

Q5. What are your current duties and responsibilities?

A5. In 2024, I was promoted to Supervisor – Program Management in the Resource Planning & Transmission Modeling group. In this role, I lead the financial analysis and evaluation of potential resources for consideration in IRP modeling. I work closely with the Company's internal subject matter experts to obtain and validate inputs for the RP&TM team to use in modeling. In addition, I assist with the preparation and review of exhibits for witnesses in rate case hearings regarding asset revenue requirements.

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. Yes. I am a registered Professional Engineer in Michigan.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to:

- Support the financial, cost, and operational assumptions for select resources utilized in the 2026 IRP modeling, including impacts from the enacted One Big Beautiful Bill Act (OBBBA)
- Support the economic analysis of selected peaker units as part of a broader analysis in which those units are considered for potential retirement
- Describe and support the risk analysis that was completed, specifically the stochastic economic risk assessment and an evaluation of key inputs

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-3	Model Data Assumptions – General Detail and References
A-3.1	Peaker Units – Economic Analysis – LCOC Results

Q10. Were these exhibits created by you or at your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following three parts:

Part I	Model Assumptions
Part II	Economic Analysis of Peaker Units
Part III	Stochastic Analysis

Line No.

PART I: MODEL ASSUMPTIONS

Q12. The Company's IRP capacity expansion and production cost modeling includes inputs for several different financial, cost, and operating parameter assumptions. Are you sponsoring any of the inputs used in this IRP?

A12. Yes. I am supporting the assumptions regarding financial data, capital and operations and maintenance (O&M) costs, and operating parameters for a specific set of new alternative resources being considered in the IRP optimization modeling, which uses EnCompass as the modeling tool. As mentioned by Witness Manning, there are various steps associated with conducting the Company's IRP process. Among the eight steps listed and expanded in her testimony, the development of the modeling inputs sponsored in this section is included as part of step 3b.

Q13. Can you describe the financial data assumptions included in EnCompass?

A13. Yes. The financial assumptions embedded in the modeling process are detailed in Table 1 below.

Table 1 Financial Assumptions

Financial Assumptions	Case No. U-21860
Long-Term Debt	50.00%
Common Equity	50.00%
Cost of Debt	4.27%
Cost of Equity	9.90%
Cost of Capital	5.64%
Discount Rate	7.00%
Tax Rate	25.91%

The Company used the debt/equity ratios, cost of debt, cost of equity and cost of capital as approved in DTE Electric's most recent general rate Case No. U-21860.[1] The pre-tax marginal cost of capital was used to calculate the return on rate base. The capital pre-tax weighted cost was used as the discount rate in calculating the annual revenue requirement streams' net present value. The capital after-tax weighted cost was used to calculate the Allowance for Funds Used During Construction (AFUDC).

Q14. In addition to the financial data assumptions described above, what is the general rate of inflation assumed in the IRP modeling?

A14. The IRP modeling uses a deflator series based on the Unadjusted Consumer Price Index (CPI) as published in September, 2025[2]. This deflator series represents an inflation rate that is used throughout the IRP modeling process and is tied to the sales forecast developed by the load forecasting group. Based on the deflator series, the annualized simple average inflation rate for the 2027-2046 period yields 2.36%.

Q15. What technologies are you sponsoring cost and operational assumptions for?

A15. I am supporting the inputs and assumptions for the natural gas, renewable, energy storage, nuclear, and hydrogen fueled technologies that are included in the EnCompass model.

Q16. What are the cost and operational assumptions used for resources included as alternatives in the EnCompass model?

[1] MPSC, Order in Case No. U-21860, February 19, 2026, p 290.
[2] S&P Global US Economic Outlook September 2025

A16. Exhibit A-3 provides the capital and O&M cost estimates, and operating performance characteristics used for the various technology resources included in the modeling. Witness Manning further describes how these assumptions are incorporated into modeling.

Q17. What sources did the Company use as the basis for determining cost and operating parameter inputs for the various technology resources?

A17. The Company used six sources as primary sources to determine inputs for the various technology resources incorporated into the modeling.

- The first source is the bid responses to the 2025 All-Source Request for Proposal (RFP) as described by Witness Pratt, which was used as the basis for determining inputs for the carbon capture and storage (CCS) ready combined cycle gas turbine (CCGT) plants, Michigan Power Cogeneration gas facility, and four (4) hour lithium ion batteries.
- The second source is the results from the 2025 All-Source Renewable Energy RFP for renewable energy resources as described by Witness Bilyeu, which was used as the basis for determining inputs for solar and wind technologies.
- The third source is technology-specific summary reports produced by the Electric Power Research Institute's (EPRI) TAGWeb software. The TAGWeb software is a planning tool that incorporates conventions from EPRI's Technical Assessment Guide and is updated with DTE Electric-specific financial information to produce cost information for technologies such as small modular reactors, advanced nuclear plants, and long-duration

Line No.

energy storage (compressed air, iron air and molten salt storage technologies).

- The fourth source is Idaho Power's 2025 IRP, used as the basis for iron air long duration storage technology capital costs.
- The fifth source is the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2026,[3] which was used as a basis for determining inputs for mostly dispatchable resources such as gas-fueled and nuclear technologies. The technologies considered included hydrogen-fueled combustion turbines, biomass with carbon capture and storage, and projections for the cost curves for nuclear technologies.
- The sixth source is the National Lab of the Rockies (NLR), formerly National Renewable Energy Laboratory's (NREL), 2024 Annual Technology Baseline (ATB) report.[4] The latest NLR published report of technology-projected operating parameters and cost forecasts was in 2024 at the start of the modeling process. This report includes a full narrative on the underlying assumptions, sources, and justifications for the forecasts provided. The technologies considered for the modeling include renewables and carbon-free options such as solar, wind, storage, and solar plus storage. The operational characteristics of the Lithium-Ion storage for 4, 6 and 10 hour durations are also obtained from the ATB, including assumptions on battery life of 15 years and the O&M costs associated with augmentation. The NLR data was used for projecting the future year cost curves of the technologies.

[3] The general publicly available source EIA can be found at https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf , accessed April 16, 2026.
[4] The report is publicly available on NREL's website at Data | Electricity | 2024b | ATB | NLR, accessed May 14, 2026.

For further detail on the assumptions from the respective sources of information, RFP results, EPRI, EIA and NLR, refer to Exhibit A-3. The Company started the IRP modeling process in 2026 using the latest available information from sources.

Q18. Do the technology cost sources used in the EnCompass model meet the IRP filing requirements?

A18. Yes. The thermal and wind costs were based on RFP responses, which reflect the current industry expectations. Additionally, solar and energy storage costs reflect the declining cost curves published in the 2024 ATB. Finally, the resource prices and costs are presented in nominal dollars.

Tax Credit Considerations Inclusive of the OBBBA

Q19. What assumptions did the Company incorporate related to the effects of tax credits for certain technologies in the inputs?

A19. The federal Production Tax Credit (PTC), Investment Tax Credit (ITC), and Carbon Oxide Sequestration Credit (CCS) are federal income tax incentives designed to encourage investment in and production of clean energy and carbon management technologies. The PTC is codified in Section 45 of the Internal Revenue Code (IRC), 26 USC Sec. 45, the ITC is codified at Section 48 of the IRC and the CCS credit is codified under Section 45Q. The tax credits are applied to various resources to reduce the revenue requirements of the portfolios where they are applied.

Q20. Are the assumptions on tax credits inclusive of the changes from the One Big Beautiful Bill Act (OBBBA)?

A20. Yes. As Witness Hajj discusses in her testimony, the OBBBA modified the availability and timing of certain federal clean energy tax credits, which are reflected in the assumptions used in the model input.

Q21. What resource types were assumed to qualify for the PTC in the modeling?

A21. Nuclear technologies, both new facilities and additional capacity for the Fermi 2 Nuclear Plant are considered to qualify for the PTC. For purposes of the model, the applicable credit rate is assumed to be $30 per megawatt-hour for projects placed in service after 2021, adjusted for inflation.[5] The PTC is assumed to be available for new nuclear projects the 10-year period beginning on the date the facility is placed in service. Additionally, for modeling purposes, nuclear facilities placed in service on or before 2036 are assumed to satisfy the applicable begin-construction requirements through application of a four-year safe harbor period.

Q22. Are wind and solar resources assumed to qualify for the PTC or ITC in the modeling?

A22. No. The OBBBA modified the availability and timing of certain IRA clean energy tax credits. In particular, OBBBA accelerated the termination of the Section 45Y production tax credit and Section 48E investment tax credit for certain wind and solar facilities. For applicable wind and solar facilities, the OBBBA generally terminates these credits for facilities placed in service after December 31, 2027, if construction begins after July 4, 2026. Although wind and solar facilities placed in service by the end of 2027 (or later, if qualifying under the applicable safe harbor rules) may be eligible for the PTC or ITC, the first year in which wind and solar

[5] Federal Register/Vol. 90, No. 100

resources could be selected in the model of 2028 would not meet the safe harbor requirement for start of construction prior to July 4, 2026.

Q23. What resource types were assumed to qualify for the ITC in the modeling?

A23. The Company assumed that battery energy storage systems, including lithium-ion battery projects, long duration energy storage (LDES) and solar plus storage projects qualified for the ITC. The ITC is equal to a specified percentage of the eligible tax basis of the energy property and is claimed in the taxable year in which the property is placed in service. For purposes of the model, the ITC is assumed to equal: (i) 30% for projects commencing construction before 2034, and are placed in service before 2038, (ii) 22.5% for projects commencing construction before 2035, and are placed in service before 2039, and (iii) 15% for projects commencing construction before 2036 but placed in service before 2040.

Q24. What other resources qualify for tax credits in the modeling?

A24. The Company assumed carbon capture and storage projects qualify for the carbon oxide sequestration tax credit under Section 45Q of the IRC. For modeling purposes, eligible projects receive a tax credit of $85 per metric tonne of qualified carbon oxide that is captured and permanently sequestered, subject to inflation adjustments for a 12-year period beginning on the date the carbon capture equipment is placed in service. The model assumes the tax credit is applied to projects that achieve CCS operation by 2036.

Q25. What tax credit assumptions were used in modeling?

A25. For purposes of modeling, the Company used the following set of assumptions:

1. Utility Storage Projects: ITC equivalent to 30% of capital costs[6];
2. Utility Solar Plus Storage Projects: ITC equivalent to 30% of capital costs of the storage equipment only. As previously mentioned, solar did not receive a credit because start of construction requirements for safe harboring for new resources have expired;
3. CCS-ready CCGT: Specific CCS tax credit equivalent to $85 in 2026 and inflation adjusted thereafter per permanently captured and sequestered tonnes of CO_2. Projects must be started by 2032 and placed in service on or before the end of 2036. This aligns with projects that bid into the All-source RFP that are CCS ready by the end of 2035 and would therefore be eligible for the tax credit. The credit is available for a period of 12 years from the in-service date; and
4. Small Modular and Advanced Nuclear Reactors: PTC equivalent to $30/MWh from 2026 and then adjusted for inflation, for a period of 10 years from in-service date.

Q26. What did the Company assume for a time limit or phase out of the tax credits due to the OBBBA?

A26. The Company incorporated the tax credit eligibility timelines established under the OBBBA into its modeling assumptions. Consistent with this, resource additions placed in service beginning in 2038 received reduced ITC tax credits and were phased out by 2040. Therefore the model reflects tax credits only for projects that meet the applicable eligibility and timing requirements as discussed above.

[6] For modeling purposes the ITC is applied to full capital costs without addition of AFUDC. The ultimate tax credit values are determined through a cost segregation analysis conducted by an independent accountant during project execution.

PART II: ECONOMIC ANALYSIS OF PEAKER UNITS

Q27. Witness Pratt discusses the Company's analysis to evaluate certain peaking units. Can you describe your role in this peaker analysis?

A27. Yes. As described by Witness Pratt, the Company performed an analysis of certain peaking generation units within its fleet in response to the 2022 IRP Settlement Agreement in Case No. U-21193. As part of the analysis, my role was to perform an economic analysis as it relates to the capacity value of these peakers.

Q28. What was the objective of the economic analysis of peakers?

A28. The Company performed an analysis to economically value the units between two options: 1) retain operations, or 2) retire. Under the retire option, it may be necessary to replace the retiring units with distribution solutions in order to maintain grid reliability.

Q29. What is the comparable metric used in the economic analysis?

A29. The Company performed an economic analysis that resulted in a determined levelized cost of capacity (LCOC) for each option (retain or retire). The LCOC is a metric or measure expressed in $/kW-yr of the average net present cost of available or installed capacity for a unit or set of generation units over an estimated operational time. Specifically, this metric is a reasonable estimate of the economic value of a peaker unit to the extent that the main benefit from its operations is to quickly start up to meet peak demand.

Q30. Are there limitations in the use of the LCOC to comprehensively evaluate options for peaker units?

A30. Yes. The main limitation is that the LCOC, as an individual metric, considers capacity as the only benefit, and disregards other benefits that could be gained from the resource. For instance, LCOC does not adequately represent the use of those peaking units as support for the distribution system as Witness Singh describes in more detail.

Q31. What inputs were considered to complete the economic analysis?

A31. The Company relied on different sources of information to populate the calculation that determines the LCOC. For the retain option, estimates of capital and O&M costs were incorporated as provided by Witness Guillaumin. For the retirement option, estimates of upgrades on the distribution and subtransmission systems as provided by the Distribution Operations (DO) team and forecasted annual capacity pricing were incorporated, along with the peaker retirement costs as described by Witness Pratt.

Q32. What forecasted annual capacity pricing was assumed in the economic analysis?

A32. The Company used the Siemens Capacity Price Forecast as the assumed cost of replacing capacity from retired units.

Q33. What were the results of the economic analysis?

A33. Exhibit A-3.1 shows the resulting calculated LCOC metric of both the retain and retire options for each set of peaking units that were analyzed. The list of units and their recommended best option are shown in Table 2 below.

Line No.

Table 2 Peaker Units – Economic Analysis – Recommended Options

Peaker Units	Annual Capacity *(MW - 2027)*	Economic Screening Results Retain or Retire
Northeast	99	Retain
Delray	118	Retain
Hancock 11	27	Retain
Colfax	12	Retain
Oliver	10	Retain
Wilmot	11	Retain
Subtotal Retain	**277**	
Superior	52	Retire w/ DO Upgrade
Subtotal Retire/Upgrades	**52**	
Total	**329**	

Q34. What factors did the Company consider in the retirement of generation units, including peakers?

A34. The Company considered an economic analysis to provide a general guideline for the reasonableness and prudency of continued operations of a generating unit. However, in addition to economics, there are other factors that need to be considered when a generation unit is being considered for retirement. See Witness Pratt for other factors that were considered.

PART III: STOCHASTIC ANALYSIS

Q35. What is a stochastic analysis?

A35. A stochastic analysis is an advanced modeling technique that incorporates uncertainty over time by assigning time-indexed probability distributions to key input variables. Building upon the deterministic set of assumptions, stochastic

analysis or modeling is performed repetitively from hundreds to thousands of times, with each iteration drawing different values from these distributions. Each iteration is referred to as a "draw." This process produces a distribution of possible outcomes, creating a more robust understanding of potential variability and risk. The stochastic analysis used in the IRP being applied to evaluate both economic outcomes and system reliability provides insight into the likelihood and range of potential performance under uncertain future conditions.

Q36. Can you describe the stochastic economic risk analysis?

A36. Yes. The stochastic economic risk analysis was conducted using the EnCompass software and applied to the selected portfolios identified in the portfolio metric evaluation. This analysis evaluates the variability of portfolio costs under uncertain market, fuel price, and operational conditions. Probability distributions were applied to key drivers including load growth, natural gas prices, electricity market prices, and generating technology costs.

Q37. What variability was applied to the key drivers?

A37. For the electricity market and natural gas prices, the Company used three years of historical monthly data to develop the variability parameters, which gives sufficient data for estimating volatility while capturing the most recent market trends. This variation was applied across 100 stochastic draws for each portfolio, consistent with other benchmarked utilities. The use of Latin hypercube to generate the 100 draws supports achieving the desired distribution. The resulting price variability is shown in Figures 1-3:

Line
No.

Figure 1 – Market Prices

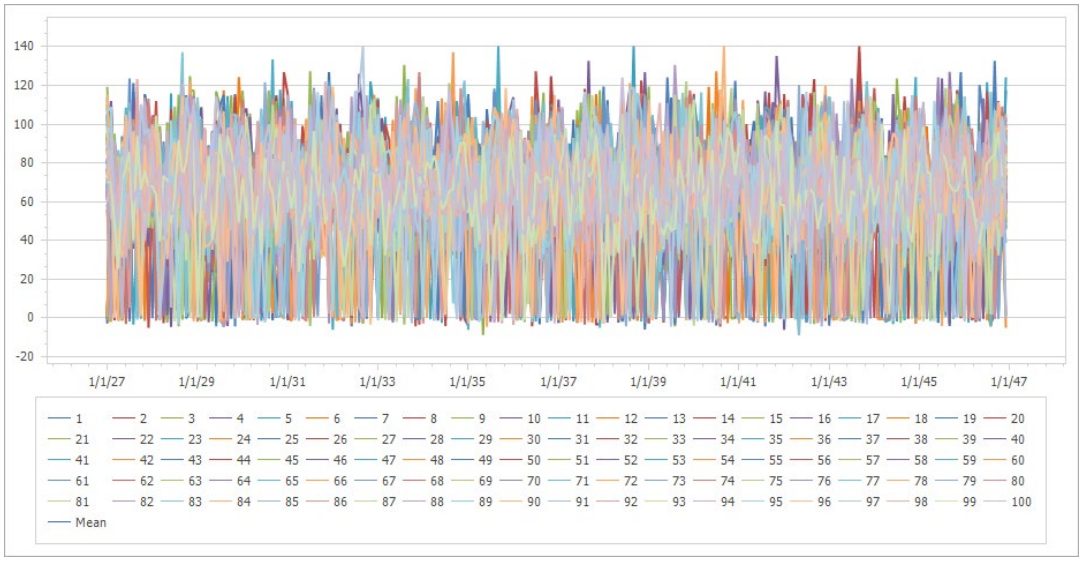
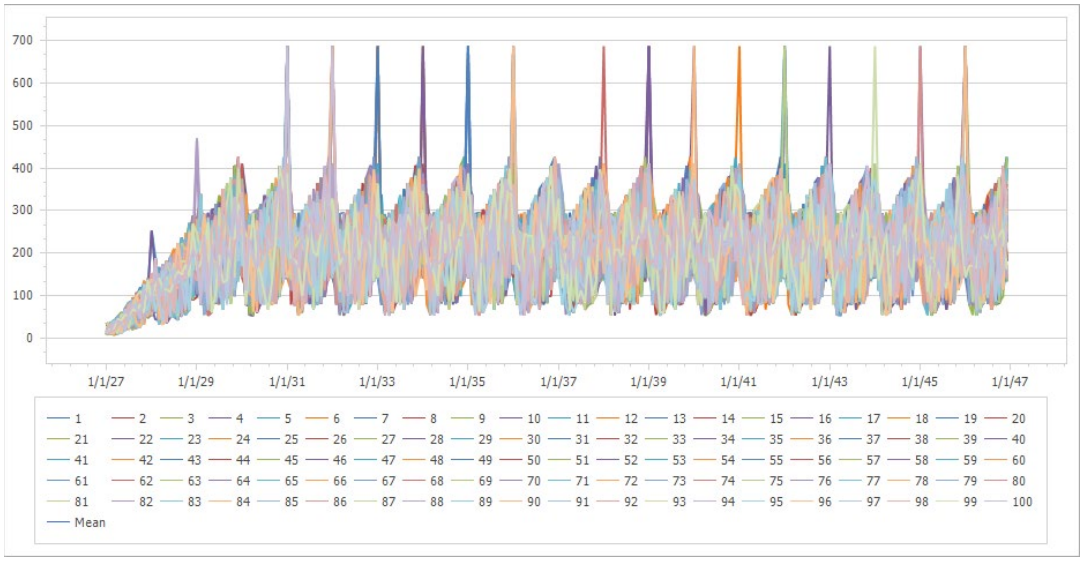
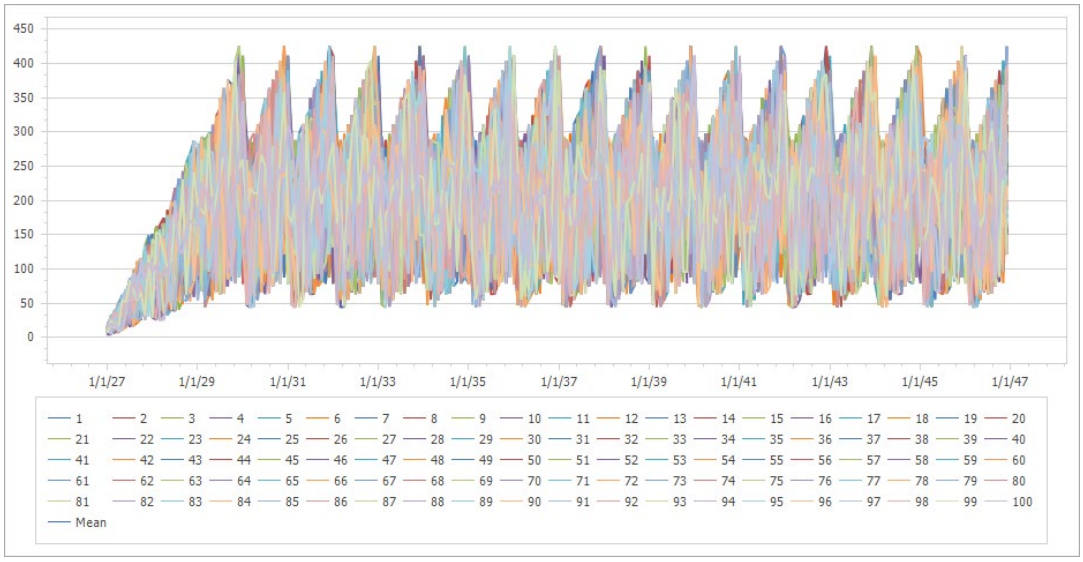


Figure 2 – Dawn Gas Prices



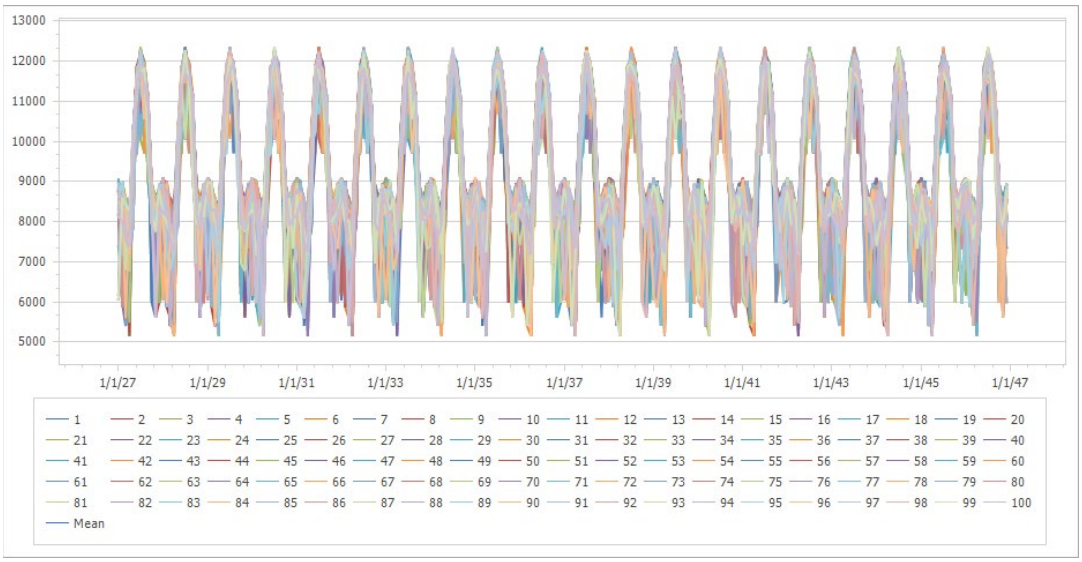
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No.

Figure 3 – Michcon Gas Prices



For the load growth, five years of historical annual peak data was used to establish the variation parameters that established the variable peak loads as inputs. The variability in peak load is shown in Figure 4:

Figure 4 – Bundled Peak



Line No.

For the technology costs, four years of historic annual price projections were used to establish the variation parameters that established the variable costs as inputs. The variability in costs are show in Figures 5-8:

Figure 5 – Solar Cap Ex

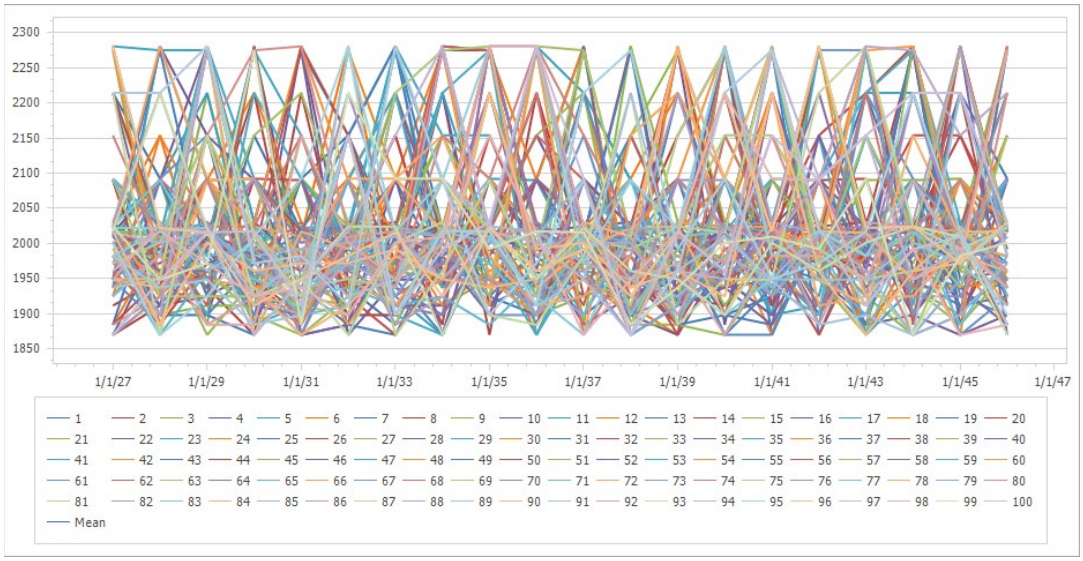
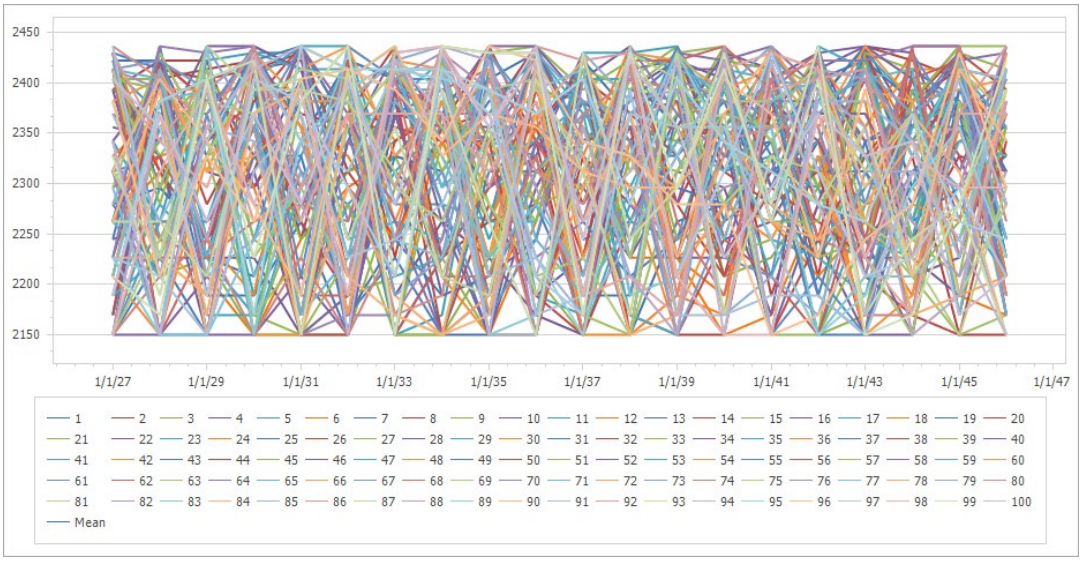


Figure 6 – 4hr Lithium Ion Cap Ex



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Figure 7 – Combined Cycle Cap Ex

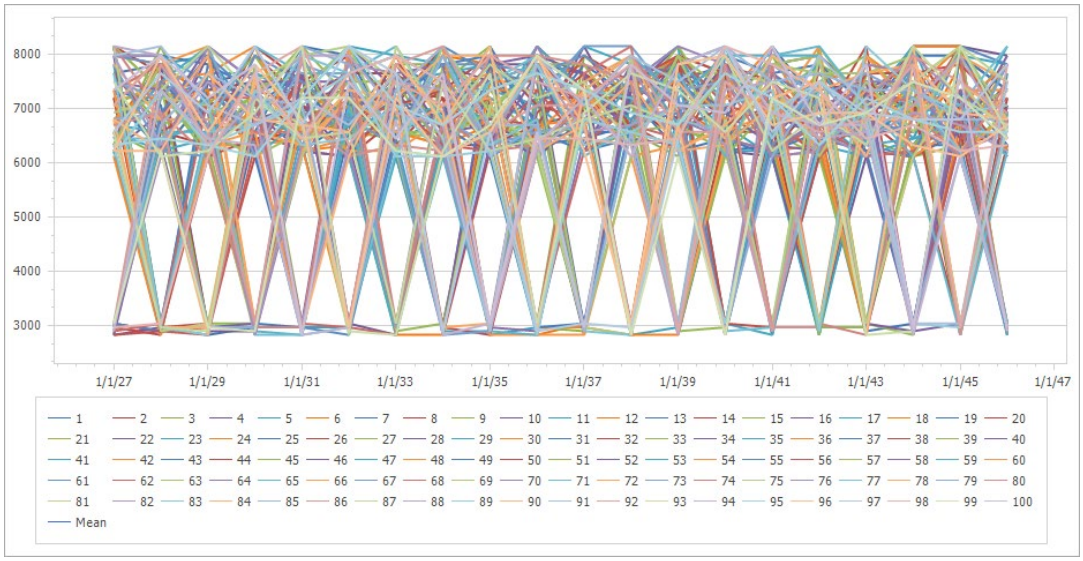
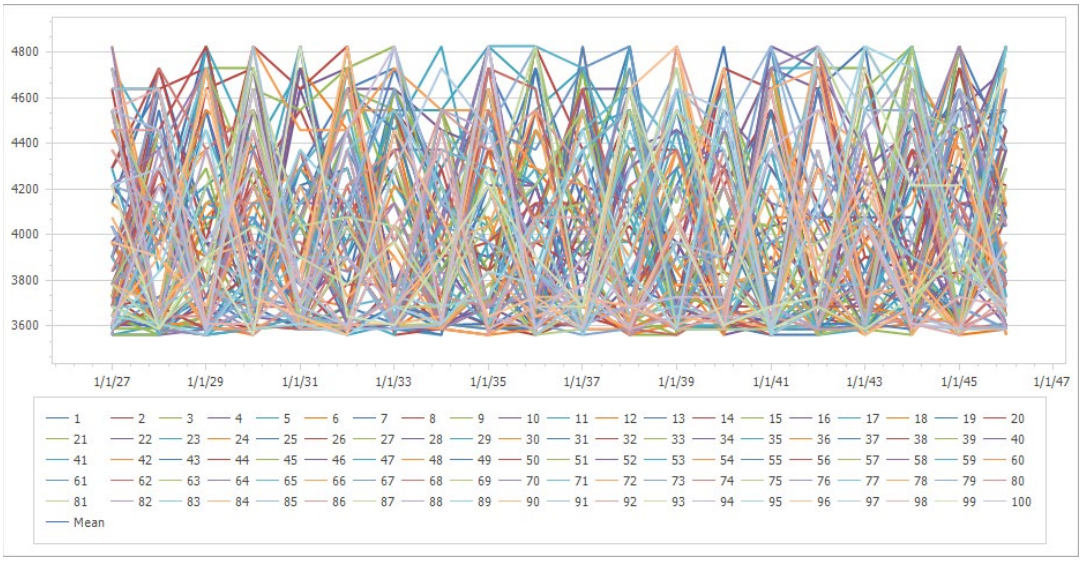


Figure 8 – Hydrogen Combustion Turbine Cap Ex



Q38. What portfolios did you evaluate in the stochastic economic risk analysis?

A38. A total of five portfolios were evaluated in the stochastic economic risk analysis, as described by Witness Manning. The list of portfolios included in the analyses are identified in Table 3.

Line No.

Table 3 – List of Portfolios Selected for Stochastic Risk Analyses

No.	Case Name
1	REF26_BASE
2	REF26_ NON_DISPATCH
3	REF26_NO_BAT_CONSTRAINT
4	REF26_NO_BUILD
5	REF26_PRELIM_PCA

Q39. How are the results of the stochastic economic risk analysis shown?

A39. The results of the stochastic economic risk analysis are presented with graphics and data that illustrate the probability distributions clearly defined along with relative positions of the distributions, so that plans can be directly compared on a single graph. This is shown with use of a box and whisker plot, which displays the portfolio cost variation. The "X" within the box represents the mean portfolio NPV, while the line represents the median. The box itself represents the 25^{th} to 75^{th} percentile bands of the portfolio NPV, while the whiskers extend to the most extreme observations within 1.5 times the interquartile range. Points beyond the whiskers are shown individually as outliers of the portfolio costs that are unlikely to occur, but not impossible given the parameters of the analysis.

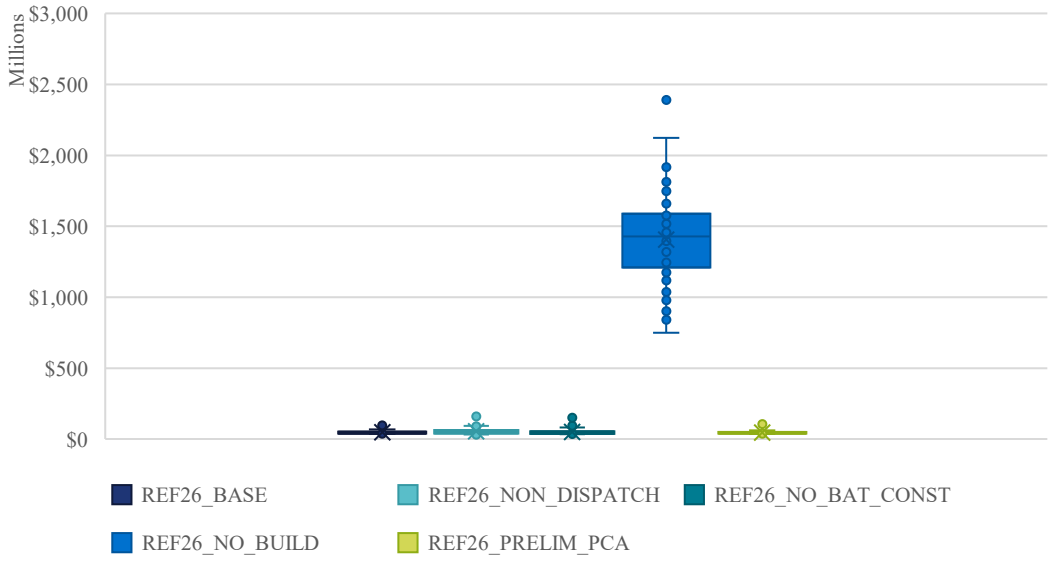
Q40. What were the results of the stochastic analysis?

A40. The results are shown in Figure 9. The REF26_NO_BUILD Portfolio represents the highest revenue requirement and greatest risk distribution of all plans. The NPV

Line No.

results of the revenue requirement for the REF26_NO_BUILD portfolio exceeded the other portfolios to the extent that made further comparisons difficult to decipher.

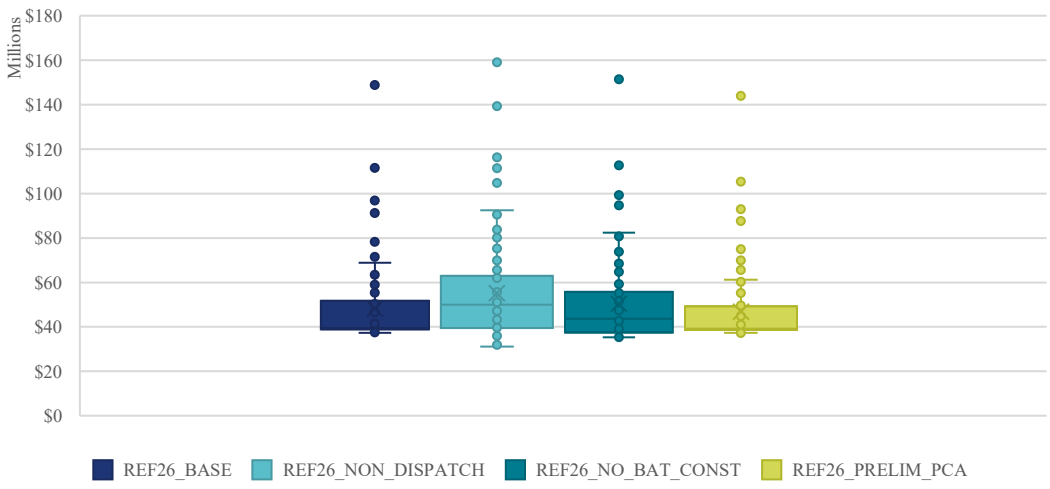
Figure 9 – Revenue Requirement Distribution of All Plans Analyzed



To compare the other portfolios, the REF26_NO_BUILD was removed in Figure 10. The REF26_PRELIM_PCA represents the most narrow stochastic economic cost distribution among the five portfolios that were evaluated. The smaller the range between the 5th and 95th percentiles represents the lower amount of risk.

Line
No.

Figure 10 – Revenue Requirement Distribution of Plans Without the REF26_NO_BUILD



Q41. Does this conclude your testimony?

A41. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

PUBLIC DIRECT TESTIMONY OF

RYAN C. PRATT

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF RYAN C. PRATT

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Ryan C. Pratt. My position is Manager – Long-Term Generation Strategy. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Nuclear Engineering from Purdue University in 2010.

Q4. What is your professional experience?

A4. During the summers of 2008 and 2009, I was employed with DTE Energy as a summer intern. During those periods, I worked in the Major Enterprise Projects (MEP) department supporting the Fermi 3 Combined License Application project. In 2010, I was hired by DTE Energy as an Associate Engineer and continued to work in MEP on the Fermi 3 project in positions of increasing responsibility until 2013.

In 2013, I transferred to the Generation Optimization department as a Principal Market Engineer. In that role, I supported the optimization of the Company's generation assets within the wholesale power market, including fuel blending, emissions management, fuel inventory management, and other strategies intended to reduce power supply cost recovery (PSCR) costs.

In 2015, I transferred to the Fuel Supply department of DTE Electric as Supervisor, Planning and Procurement and was later promoted to the role of Manager, Procurement. In those roles, my responsibilities included procuring and planning the procurement of the fuels consumed by the Company's fossil generation assets, including coal, oil, natural gas, petroleum coke (petcoke), and the transportation associated with each of those fuels. I was also responsible for planning the delivery of those fuels to the Company's power plants and forecasting fuel costs and transactions. Much of my time in Fuel Supply was focused on natural gas procurement, including developing the fuel supply strategy for the Blue Water Energy Center (BWEC), the Company's combined-cycle gas turbine (CCGT) plant that was put in service in 2022.

In 2024, I transferred to the Strategy & Corporate Development department of DTE Electric in my current role as Manager – Long-Term Generation Strategy.

Q5. What are your current duties and responsibilities?

A5. My current responsibilities include developing the long-term strategy for the Company's generation resources, including the development of the Integrated Resource Plan (IRP). My team develops strategies and plans related to the retirement of the Company's remaining coal-fired generation assets and evaluates new and existing generation technologies to replace retiring resources, meet renewable and clean energy requirements, and provide reliable and affordable energy for the Company's customers. I am also responsible for the Company's longer-term capacity procurement, including the 2025 All-Source Request for Proposals (RFP). Additionally, I am responsible for the Company's transmission

and interconnection strategies, including supporting policy development with the Midcontinent Independent System Operator (MISO).

Q6. Have you previously provided testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in the following cases:

U-17920	DTE Electric's 2016 PSCR Plan
U-17680-R	DTE Electric's 2015 PSCR Reconciliation
U-18143	DTE Electric's 2017 PSCR Plan
U-17920-R	DTE Electric's 2016 PSCR Reconciliation
U-18403	DTE Electric's 2018 PSCR Plan
U-20203	DTE Electric's 2018 PSCR Reconciliation
U-20221	DTE Electric's 2019 PSCR Plan
U-20223	DTE Electric's 2019 PSCR Reconciliation
U-20471	DTE Electric's 2019 IRP
U-20527	DTE Electric's 2020 PSCR Plan
U-20528	DTE Electric's 2020 PSCR Reconciliation
U-20826	DTE Electric's 2021 PSCR Plan
U-20827	DTE Electric's 2021 PSCR Reconciliation
U-21193	DTE Electric's 2022 IRP
U-21050	DTE Electric's 2022 PSCR Plan
U-21051	DTE Electric's 2022 PSCR Reconciliation
U-21259	DTE Electric's 2023 PSCR Plan
U-21260	DTE Electric's 2023 PSCR Reconciliation
U-21425	DTE Electric's 2024 PSCR Plan

Line No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Summarize the Company's peaker analysis presented in this IRP, including the factors considered and findings of the retirement evaluation;
- Describe the Monroe Power Plant (MNPP) natural gas conversion study conducted by the Company and present the results;
- Provide an overview of the emerging technologies considered in this IRP, including the Black & Veatch emerging technology report;
- Describe the Company's long-term nuclear generation strategy, including the continued operation of its Fermi 2 plant, the inclusion of the Fermi 2 Extended Power Uprate (EPU) project in the Proposed Course of Action (PCA), and the Company's plan to continue evaluating the development of new nuclear projects;
- Describe the Company's 2025 All-Source RFP, including the Company's evaluation, shortlisting, and selection process as well as the compliance with the MPSC's Competitive Procurement Guidelines;
- Describe the resources selected through the 2025 All-Source RFP and the resources for which the Company seeks cost pre-approval in the three years following a final order approving this IRP (2028-2030), including the [redacted] solar project and the Michigan Power Cogeneration facility; and
- Describe the Company's requests for Certificates of Necessity (CONs) under MCL 460.6s, including determinations concerning the need for power; whether the size, fuel type, and other design characteristics of each

project represent the most reasonable and prudent means of meeting that need; and the estimated capital costs for the projects.[1]

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-4	NDA_Monroe Natural Gas Conversion Study – Burns & McDonnell
A-4.1	Updated Emerging Generation Technologies Study – Black & Veatch
A-4.2	Fermi SMR Feasibility Study – Black & Veatch
A-4.3	2025 All-Source RFP – Independent Monitor Report
A-4.4	Alignment with the Competitive Procurement Guidelines
A-4.5	RFP Development Meeting Materials
A-4.6	RFP Development Meeting Feedback
A-4.7	RFP Draft Materials
A-4.8	Pre-RFP Meeting Materials
A-4.9	Pre-RFP Meeting Feedback
A-4.10	RFP Draft Materials Feedback
A-4.11	RFP Final Materials
A-4.12	2025 All-Source RFP Results
A-4.13	NDA_2025 All-Source RFP Third-Party Assessment
A-4.14	NDA_Solar Project Proposal

[1] Certificates of necessity granted under MCL 460.6s(3)(d) also include approval of financing plans for the proposed projects. Witness Uzenski supports the Company's proposed financing plans and associated financing costs for the proposed projects.

	A-4.15	NDA_Solar PPA Cost Pre-Approval Supporting Data
	A-4.16	NDA_DTESG – Michigan Power Cogeneration Proposal
	A-4.17	NDA_Purchase and Sale Agreement – Michigan Power Cogeneration
	A-4.18	MI Power Cogeneration Cost Pre-Approval Supporting Data
	A-4.19	MI Power Cogeneration Net Book Value Support
	A-4.20	NDA_DTE Electric – Livingston County and Monroe County Proposal

Q9. Were these exhibits prepared by you or under your direction?

A9. Several of these exhibits were prepared by me or under my direction. Other exhibits were prepared by third-party consultants, independent monitors, or bidders participating in the Company's 2025 All-Source RFP. I have reviewed those exhibits, relied upon them in developing my testimony, and am sponsoring them because they support the analyses, evaluations, and conclusions discussed in my testimony.

Q10. How is your testimony organized?

A10. My testimony consists of the following seven parts:

Part I	Peaker Retirement Analysis
Part II	Monroe Power Plant Natural Gas Conversion Study
Part III	Emerging Technology Overview
Part IV	Long-term Nuclear Strategy
Part V	2025 All-Source RFP Process and Results

Part VI MCL 460.6t(11) Cost Preapproval Requests for RFP Selected Resources

Part VII Certificate of Necessity Requests

PART I – PEAKER RETIREMENT ANALYSIS

Q11. What are peakers?

A11. Peakers, or peaking plants, are generation resources that typically operate during periods of high demand (i.e., during the load "peaks"). Peakers are a critical component of the generation mix, ensuring grid reliability when other resources alone cannot meet demand. As intermittent renewables increase in the generation mix, peakers are a resource that can fill in gaps when renewables are not generating and storage or other resources are not available. Peakers can typically start up quickly and have high ramp rates to meet sudden changes in demand. Peakers are typically less efficient, resulting in less frequent operation compared to baseload plants. Most peaker plants utilize technologies including simple-cycle natural gas-fired combustion turbines (CTs) or diesel engines because they are utilized less frequently than baseload plants.

Q12. What are the general characteristics of the DTE Electric peaker fleet?

A12. As discussed by Witness Guillaumin, DTE Electric has 1,928 MW of peaker generating capability in operation based on the summer capacity ratings of these units. DTE Electric has 68 natural gas and oil-fueled peakers located at 17 different sites.

Q13. What changes have occurred in DTE Electric's peaker fleet since the Company's 2022 IRP (Case No. U-21193)?

A13. The Northeast 11-1 peaker was retired in 2023 after a component failure. As recommended in the 2022 IRP, the River Rouge peakers and the St. Clair 12 diesel peakers were retired in 2024. Additionally, Fermi Units 11-3 and 11-4 operations were suspended in 2025. The Slocum peakers were retired in 2023 to support construction of the Slocum Battery Energy Storage System (BESS) project, which was commissioned in 2025.

Q14. What are the typical operating characteristics of the Company's peaker fleet?

A14. The Company's peaker fleet can be grouped into four major classes: Large Gas Turbines, Small Gas Turbines, Oil-Fired Turbines, and Diesel Engines. Table 1 summarizes the operating characteristics of the peakers, including capacity factors and energy dispatch costs of the various types of peakers.

Table 1 Peaker Operating Characteristics

Type	# of Units	Summer Capacity[2] (MW)	Capacity Factor (%)	Approximate Cost ($/MWh)	Gross Heat Rate (btu/kWh)	Approximate Fuel Cost ($/MBTU)
Large Gas Turbines	16	1,539	17.1%	$47	11,659	$4.01
Small Gas Turbines	9	174	1.7%	$98	14,532	$6.75
Oil-Fired Turbines	8	117	0.1%	$248	14,798	$16.74
Diesel Engines	35	98	0.1%	$179	10,768	$16.67
TOTAL	**68**	**1,928**				

Q15. What benefits do the peakers provide to DTE Electric's overall generation portfolio?

[2] Summer capacity as described in Witness Guillaumin's Table 1

A15. DTE Electric's peakers are a critical component of the overall generation portfolio. As firm, dispatchable resources, peakers are a key contributor to DTE Electric's ability to provide sufficient capacity resources to meet demand and ensure resource adequacy. During periods of high demand, DTE Electric's peakers provide a reliable source of energy supply, insulating customers from costly market purchases. As intermittent renewable resources continue to be added to the generation mix, peakers will continue to play an important role in ensuring reliability and balancing energy supplies. In addition, peakers also provide significant value to the grid and can support the distribution and transmission systems during stressed grid conditions.

Q16. Do DTE Electric's existing peakers contribute to the Company's clean energy portfolio?

A16. No. As noted above and described further below, although the peakers provide reliability benefits, they are not clean energy systems and do not contribute to the Company's clean energy portfolio. In addition, the Company's natural gas peakers are not equipped with carbon capture and storage (CCS) systems. While CCS technology on peakers is technically feasible, these investments would not be cost-effective given the peakers' lower capacity factors. Looking ahead, some peakers may be capable of burning hydrogen and natural gas blends with potential upgrades to burners, fuel systems, and control systems. However, because these systems blend natural gas and hydrogen fuels and continue to emit greenhouse gases, they would not be considered clean energy systems under MCL 460.1003(i).

Q17. What are clean energy systems?

A17. Per MCL 460.1003(i), clean energy systems are defined as "an electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:

i. Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

ii. Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of environment, Great Lakes, and energy determines, through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

iii. Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best

available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

iv. Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision."

Q18. What requirements related to peakers were included in the Company's 2022 IRP settlement agreement?

A18. DTE Electric's 2022 IRP Settlement Agreement in Case No. U-21193 (2022 IRP Settlement Agreement) stipulated that DTE Electric would retire the River Rouge peakers and St. Clair diesel peakers in 2024. Additionally, the Settlement Agreement[3] required that DTE Electric "provide an updated peaker analysis that includes a study of the potential retirement dates, replacement cost of capacity and other peaker functionality, non-wire alternatives, and the impacts of peakers located near environmental justice (EJ) communities (i.e., Delray, Northeast, and Superior) on those communities."

Q19. Do any other IRP statutory or IRP filing requirements apply to peakers?

A19. Yes. MCL 460.6t(5)(p) requires that IRPs include a review of reasonably anticipated EJ impacts for each fossil fuel peaking facility if the plan proposes retiring or retaining one or more peaking plants. Further, the IRP filing requirements established in Case No. U-21570 and U-21867 include additional directives relevant to peakers located near EJ communities. Under Section XXIII of the IRP filing requirements, utilities must:

[3] Settlement Agreement in DTE Electric's 2022 IRP (U-21193), p. 17

- Identify, for each portfolio, existing facilities and potential future facilities with known locations, including peaking units, that are within 3 miles of communities specified for the Environmental Justice Analysis; and
- Analyze all portfolios to quantitatively assess the projected emissions of identified facilities for each respective portfolio, and the differences in each portfolio's projected emissions for that unit relative to Portfolio 2. [4]

Q20. What analyses did the Company undertake to meet the 2022 IRP Settlement Agreement and IRP filing requirements related to peakers?

A20. Prior to filing this IRP, DTE Electric undertook a peaker retirement analysis to assess the impact of accelerated retirement dates for the peakers located near EJ communities as well as several peaker sites that are not near EJ communities. As a result of the peaker retirement analysis, the Company is recommending accelerated retirement for one of the sites located near an EJ community.

Q21. Which of the Company's peakers are located near EJ communities?

A21. As noted in the 2022 IRP Settlement Agreement, the Company's Delray, Northeast, and Superior peakers are located near EJ communities. The most recent IRP requirements revised the minimum MiEJScreen composite score that defines an EJ community from the 80th percentile to the 75th percentile; however, this change did not result in any additional DTE Electric peaker sites being identified as located near EJ communities. Delray is located in Detroit, MI, and EJ communities within 3 miles include Detroit, River Rouge, Ecorse, Melvindale, and Dearborn. Northeast is located in Warren, MI, and EJ communities within three

[4] Per Section XXIII of the IRP requirements, portfolio #2 is the utility PC portfolio run in MIRPP Scenario 1

miles include Warren, Detroit, Hazel Park, Center Line, Eastpointe, and Hamtramck. Superior is located in Superior Township, MI, with Ypsilanti identified as an EJ community within 3 miles.

Q22. Did DTE Electric analyze other peakers in addition to those located near EJ communities?

A22. Yes. DTE Electric also analyzed peaker retirements at four other sites in addition to the three peaker sites near EJ communities. The Company identified these sites based on the prioritization of smaller, less efficient peaker units. The four additional sites that were analyzed were Oliver, Wilmot, Colfax, and Hancock 11. Table 2 summarizes the seven total peaker sites that DTE Electric analyzed for the 2026 IRP.

Table 2 Peaker Sites Analyzed for the 2026 IRP

Site	City	Nearby EJ Community?	# of Units	Annual Capacity[5] (MW)	Type
Delray	Detroit	Yes	2	118	Large Gas Turbine
Northeast	Warren	Yes	6	99	Small GT & Oil Turbine
Superior	Superior Twp	Yes	4	52	Oil Fired Turbine
Oliver	Pigeon	No	5	10	Diesel Engine
Wilmot	Kingston	No	5	11	Diesel Engine
Colfax	Fowlerville	No	5	12	Diesel Engine
Hancock 11	Commerce Twp	No	2	27	Small Gas Turbine

Q23. What factors and inputs were considered in the peaker retirement analyses?

A23. There are many factors that must be considered when analyzing accelerated peaker retirement dates. To the extent possible, the Company quantified the various

[5] Annual Capacity represents the average seasonal 2027 accredited capacity

factors and utilized those inputs to perform an economic analysis comparing the retention of each peaker versus accelerated retirement of that site. The economic analysis for the peaker retirement analysis is described in more detail by Witness Busse. The factors considered in the peaker retirement analysis include:

- The generation, capacity, and resource adequacy benefits provided by the peakers when they are operating;
- The operations and maintenance (O&M) and capital costs to continue reliable operations of the peakers;
- The benefits that the peakers provide to the distribution and transmission systems and the impacts to those systems if peakers are retired; and
- The costs to decommission retired peaker sites.

Q24. How were the generation, capacity, and resource adequacy benefits provided by the peakers considered in the peaker retirement analysis?

A24. As described above, the peakers provide many benefits as part of the overall DTE Electric generation portfolio. For the purposes of the economic analysis, the primary consideration is the value of the accredited capacity provided by the peakers compared to replacement capacity cost. The capacity considerations for the economic analysis are described in more detail by Witness Busse. Because the sites included in the peaker retirement analysis are generally among the Company's smallest and least efficient peaker units (except for Delray), the economic analysis did not consider any energy value derived from the peakers' generation. However, as described above, the peakers do provide a reliable source of energy supply that insulates customers from costly market purchases during periods of high demand. In total, the peakers analyzed for the peaker retirement

analysis represent 329 MW of average seasonal accredited capacity that would need to be replaced or otherwise addressed to maintain resource adequacy if those peakers were retired.

Q25. What O&M and capital costs were considered in the peaker retirement analysis?

A25. The O&M and capital costs necessary to ensure the continued reliable operation of the peakers were included in the economic analysis for the peaker retirement analysis. The O&M and capital costs are described in more detail by Witness Guillaumin. The O&M requirements for peakers are minimal relative to the generation and capacity they provide; however, the peakers do require scheduled inspections and long-term investments to ensure their continued reliable operation.

Q26. What benefits do the peakers provide to the distribution and transmission systems?

A26. As dispatchable generation, peakers provide multiple benefits to the distribution and transmission systems. Peakers may be dispatched by MISO or DTE Electric to support grid reliability, while DTE Electric and ITC coordinate regarding distribution, transmission, and system-restoration needs, as applicable. Peakers provide voltage grid support and may also support system restoration as blackstart resources in the event of a blackout.

Q27. How were the distribution system benefits associated with peakers considered in the peaker retirement analysis?

A27. As described above, peakers may be dispatched by DTE Electric to maintain distribution system reliability. In the event of accelerated peaker retirements, DTE Electric may need to make investments in the distribution system to maintain reliable service for its customers. These costs were quantified for each peaker site and included in the economic analysis for the peaker retirement analysis.

Q28. How were the distribution system benefits associated with peakers determined and quantified?

A28. The Company performed studies to assess the distribution system impacts of a peaker retirement at each site. These studies identified distribution system mitigations and modifications requiring additional investments. The distribution studies are described in more detail by Witness Singh.

Q29. Did DTE Electric consider adding other generation or capacity resources at the peaker sites to mitigate the distribution system impacts?

A29. Yes. The Company considered adding other resources at peaker sites – specifically 4-hour energy storage resources. While energy storage resources have similar characteristics to peakers in that they can provide energy during peak periods, the duration-limited nature of current 4-hour storage technologies means it is not an equivalent substitute for the distribution system services provided by the peakers in the scenarios studied. The ability of peakers to provide continuous, uninterrupted generation – sometimes for days – is critical to their ability to provide support to the distribution system. The distribution scenarios requiring peaker support often greatly exceed the duration of 4-hour storage. The impact of storage on the distribution system is discussed in more detail by Witness Singh.

Q30. Are there any other distribution or transmission system benefits associated with the peakers that were not quantified?

A30. Yes. Peakers produce other grid benefits that were not quantified for the economic analysis. Peakers provide voltage support to the grid and may also support system restoration as blackstart resources in the event of a blackout. These are key services that must be considered as part of the peaker retirement analysis.

Q31. What are blackstart resources?

A31. Blackstart resources are a critical component of system reliability addressed through reliability requirements established by the North American Electric Reliability Corporation (NERC) and defined in ITC's System Restoration Plan (SRP). These resources can start up without off-site power and can initiate the process of system restoration after a blackout. Blackstart resources allow for a cranking path to be energized, allowing for larger generation resources to be started to support overall system restoration. As a generation owner in the ITC territory, DTE Electric plays a key role by providing blackstart resources to support the SRP. As firm, dispatchable generation that can start quickly with low auxiliary load, peakers are ideal blackstart resources.

Q32. How were peaker decommissioning costs considered in the peaker retirement analysis?

A32. In 2024, DTE Electric commissioned studies from Sargent & Lundy (S&L) to assess the decommissioning costs of various generation resources. As part of that effort, S&L completed decommissioning studies for each of the peaker sites

considered in the peaker retirement analysis.[6] The studies identified decommissioning costs of between $1 million and $3 million for each site. These costs were included in the economic analysis for the peaker retirement analysis.

Q33. What were the results of the Company's peaker retirement analysis and what recommendations does the Company make regarding the peaker units analyzed?

A33. The results of the economic analysis for the peaker retirement analysis are described in more detail by Witness Busse and shown in Exhibit A-3.1, Peaker Units – Economic Analysis – LCOC Results. Based on the economic analysis, the Company recommends the accelerated retirement of the Superior site in 2032 and continued operation of the remaining six peaker sites. The Superior site is one of the Company's three peaker sites located near an EJ community. The Company recommends continued operation of the Delray and Northeast peaker sites, which are also located near EJ communities.

Q34. Why is the Company recommending the retirement of the Superior peakers in 2032?

A34. Time is needed to prepare, plan, and execute the actions necessary to support the recommended retirement of the Superior peakers. DTE Electric must continue to ensure resource adequacy, especially during the critical upcoming period that includes the retirement of the Monroe Power Plant Units 3 and 4 in 2028 and Units 1 and 2 in 2032. As discussed in more detail in Part V, new firm, dispatchable generation capacity is expected to become available between 2030 and 2032.

[6] Case No. U-21772, Revised Exhibit A-7

Additionally, DTE Electric must continue to ensure reliable operation of its distribution system and implement necessary mitigation projects before retiring the Superior peakers. Accordingly, the recommended 2032 retirement date provides time to implement the replacement capacity and distribution system measures necessary to support the retirement while maintaining reliable service.

Q35. How does DTE Electric intend to identify and select new generation resources to replace the retiring Superior site in 2032?

A35. As described in Part V below, DTE Electric conducted an All-Source RFP to identify new generation resources to be available by 2032. DTE Electric has selected resources from the All-Source RFP to fulfill its overall generation and capacity needs, which includes the replacement of the Superior peakers.

Q36. Why is DTE Electric recommending continued operation of Delray and Northeast despite their locations near EJ communities?

A36. As described above, the economic analysis found that continuing to operate Delray and Northeast was economic compared to accelerated retirement. As a large gas turbine, Delray is among DTE Electric's largest and most efficient peakers, and the Company has made investments into the units in recent years to ensure they remain efficient and reliable. Delray provides 118 MW of average seasonal accredited capacity and provides support to the grid. The Northeast units are small gas turbines and oil-fired turbines that provide 99 MW of average seasonal accredited capacity. The Northeast units also support DTE Electric's distribution system during periods of grid stress. The capacity, operational, and distribution system benefits provided by Delray and Northeast, together with the costs and

other considerations associated with accelerated retirement, support the Company's recommendation to continue operating both sites.

Q37. What is the expected impact of the peakers located near EJ communities on those communities?

A37. While peakers are gas- and oil-fired and are less efficient than baseload units, their emissions impact is limited by their relatively low capacity factors of 0% to 20%. The impact of peakers located near EJ communities on those communities is discussed in more detail by Witness Marietta.

Q38. What assumptions were made for the 2026 IRP modeling based on the results of the peaker retirement analysis?

A38. As a result of the peaker retirement analysis, the 2026 IRP modeling, as supported by Witness Manning, assumes that Superior will retire in 2032. The other peakers are assumed to continue operating throughout the IRP forecast.

Q39. Does the Company's peaker retirement analysis meet the requirements of the 2022 IRP Settlement Agreement, the IRP statute, and IRP filing requirements?

A39. Yes. DTE Electric's peaker retirement analysis exceeds the requirements of the 2022 IRP Settlement Agreement, MCL 460.6t(5)(p), and Section XXIII of the IRP requirements. The Company provided an updated peaker analysis that includes not just its peakers located near EJ communities, but also additional peakers that are not located near EJ communities. DTE Electric also completed EJ analyses for peakers near EJ communities.

PART II – MONROE POWER PLANT NATURAL GAS CONVERSION STUDY

Q40. What requirements related to a Monroe Power Plant natural gas conversion were included in the Company's 2022 IRP Settlement Agreement?

A40. Per the 2022 IRP Settlement Agreement, DTE Electric was required to "include a natural gas conversion study for Monroe" in its next IRP filing.

Q41. Does DTE Electric have experience with natural gas conversions of coal plants?

A41. Yes. In the 2022 IRP, DTE Electric proposed the conversion of Belle River Power Plant from coal to natural gas. The costs for the conversion were approved by the Commission via the 2022 IRP Settlement Agreement (pp. 2-3) and the parties agreed that the 2022 IRP Proposed Course of Action would include the conversion of Belle River. Belle River Unit 1 was converted to gas in December 2025, as planned. The unit has since operated reliably as a gas-fired unit. The conversion of Unit 2 is expected to be completed in December 2026.

Q42. Is a natural gas conversion at the Monroe Power Plant comparable to the natural gas conversion at the Belle River Power Plant?

A42. While there are similarities between Belle River Power Plant and Monroe Power Plant with regard to a natural gas conversion, there are also key differences between the plants that necessitate additional analysis. The four Monroe Power Plant units are slightly larger (approximately 760 MW each) than the two Belle River Power Plant units (approximately 635 MW each). As discussed in more detail below, the Belle River Power Plant and Monroe Power Plant sites differ significantly in their availability of natural gas supply. Belle River Power Plant

has multiple natural gas transmission pipelines located within approximately one mile of the site, while the nearest natural gas transmission pipelines for Monroe Power Plant are located between 12 and 23 miles from the site.

Q43. Are there federal environmental regulations related to natural gas conversion for coal plants?

A43. Clean Air Act (CAA) Section 111(d) rules define best systems of emissions reduction requirements for coal plants retiring by various dates. Coal units retiring or converted to natural gas by 2031 were exempted from the requirements. For units operating beyond 2031 and through 2038, 40% natural gas co-firing by the end of 2029 was identified as the best system of emissions reduction. These rules were in place at the time the Company initiated its Monroe Power Plant natural gas conversion study and were considered in the analysis. However, the Environmental Protection Agency (EPA) on September 14, 2026, finalized a partial repeal of the 2024 Section 111 rule, including the emission guidelines for existing coal-fired units, and proposed repeal of the remaining Section 111 greenhouse-gas standards.

Q44. When did the EPA propose to repeal Section 111 rules, and what action has it taken since?

A44. The EPA proposed to repeal all greenhouse gas standards for fossil fuel-fired power plants, including Section 111, in June 2025. On September 14, 2026, EPA finalized a partial repeal of the 2024 rule, including the emission guidelines for existing coal-fired units, and proposed repeal of the remaining Section 111

greenhouse-gas standards. Witness Marietta describes the Section 111 rules in more detail.

Q45. Are coal plants that are converted to natural gas considered clean energy resources under Michigan's clean energy requirements?

A45. No. Coal plants that are converted to natural gas are not considered clean energy systems as defined in MCL 460.1003(i) and do not contribute to the Company's clean energy portfolio. The Belle River Power Plant is not equipped with CCS systems, and DTE Electric has not contemplated that Monroe Power Plant would be equipped with CCS systems if converted to natural gas. While the installation of CCS systems on coal plants converted to natural gas is technically feasible, investments in CCS would be cost prohibitive due to the significant capital costs and relatively less energy production from a converted plant that operates as a peaking unit compared to a more efficient, baseload CCGT.

Q46. How is a coal plant that is converted to natural gas expected to operate?

A46. Coal plants that are converted to natural gas are generally expected to operate as peaking resources. As described in Part I, peakers are generation resources that operate typically during periods of high demand (i.e., during the load "peaks"). Peakers are a critical component of the generation mix, ensuring grid reliability when other resources alone cannot meet demand.

Q47. Did the Company complete a natural gas conversion study for Monroe Power Plant as required by the 2022 IRP Settlement Agreement?

A47. Yes. The Company completed a natural gas conversion study for Monroe Power Plant. DTE Electric commissioned a study from Burns & McDonnell to further evaluate the scope of work to convert the Monroe Power Plant units from coal to natural gas. The study, which was finalized in April 2025, is provided as NDA Exhibit A-4. Burns & McDonnell provided conceptual engineering design details and a project cost estimate. Based on the findings from the natural gas conversion study, DTE Electric is not recommending the conversion of Monroe Power Plant to natural gas.

Q48. What are the primary considerations for the natural gas conversion study?

A48. There are several considerations for the natural gas conversion study. These included the work and cost to convert the units from coal-fired to gas-fired, as well as the decommissioning of coal systems and installation of natural gas burners. Additionally, it was necessary to assess the available natural gas fuel supply at the site and determine the costs and feasibility of procuring and delivering natural gas supplies to the site. After assessing the costs of converting Monroe Power Plant to natural gas, the Company completed an economic analysis to compare the cost of a Monroe natural gas conversion to other available alternatives.

Q49. What gas conversion cases were evaluated in the natural gas conversion study?

A49. The Burns & McDonnell study evaluated three separate gas conversion cases:

- Case 1 – 40% gas co-firing on Units 1 and 2
- Case 2 – full gas conversion for Units 1 and 2
- Case 3 – full gas conversion for Units 1 through 4

While three cases were analyzed, Case 1 is no longer expected to be applicable given EPA's September 2026 repeal of the applicable existing-coal emission guidelines and Case 3 is less feasible given the extremely large gas supply requirements and the limited timeline to interconnect to the gas system and convert Monroe Power Plant Units 3 and 4 prior to their planned retirement in 2028. Therefore, the Company focused on Case 2 – full gas conversion of Units 1 and 2.

Q50. What plant modifications are necessary to convert the units from coal-fired to gas-fired?

A50. The primary plant modification necessary to convert the units from coal-fired to gas-fired is the replacement of the existing coal burners with gas-fired burners. New ultraviolet flame scanners would be installed with the new gas burners, as well as low-pressure gas control skids with control valves and instrumentation to be integrated with the plant's control system. A new fuel gas yard would be constructed on-site for metering, regulation, and conditioning of the gas, as well as a low-pressure gas delivery system to deliver gas to the burners.

Q51. What costs were identified by Burns & McDonnell to complete the plant modifications?

A51. The gas conversion costs identified by Burns & McDonnell are shown below in Table 3 for each case. While Burns & McDonnell also assessed the gas pipeline costs, DTE Electric developed separate gas pipeline cost estimates as discussed in more detail below.

Line No.

Table 3 Burns & McDonnell Gas Conversion Cost Estimates

Case	Cost Estimate
Case 1	$167.4M
Case 2	$249.7M
Case 3	$489.2M

Q52. Did the Company make any adjustments to the Burns & McDonnell Monroe Power Plant natural gas conversion estimate?

A52. Yes. The Company made three adjustments. The first adjustment was adding $10 million of flue gas desulfurization (FGD) and stack work not included in the Burns & McDonnell study to accommodate for modifications needed for the change in heat profile on the equipment. The second adjustment was adding 18% to the conversion costs to account for corporate overhead costs not included in the Burns & McDonnell study. The third adjustment was incorporating cost escalation into the projection. Cost escalations were not included in the Burns & McDonnell study; therefore, the Company incorporated a 2-3% cost escalation per year into the projected costs. In total, these adjustments added approximately $120 million to the Case 2 projection, resulting in the $370 million forecast in Witness Guillaumin's Exhibit A-9, line 22.

Q53. What are the natural gas fuel requirements for Monroe if converted to natural gas?

A53. Given the overall size of Monroe Power Plant, the natural gas requirements for the plant are substantial. The estimated natural gas requirement for each unit is approximately 180,000 Dth/d if fully converted to natural gas. The natural gas requirements for each case are shown below in Table 4. For the full conversion of

the entire plant, the gas supply requirement is approximately 720,000 Dth/d. For the purpose of comparison, that quantity of natural gas is equivalent to four of the Company's BWEC CCGT plants (approximately 5 GW of generation capacity) or nearly half of the capacity of the NEXUS pipeline[7], which was built in 2018 to deliver Appalachian natural gas supplies to Michigan.

Table 4 Monroe Natural Gas Supply Requirements

Case	Gas Requirement (Dth/d)
Case 1	144,000
Case 2	360,000
Case 3	720,000

Q54. How would natural gas be supplied to the Monroe Power Plant site?

A54. The Monroe Power Plant site does not have existing natural gas pipeline infrastructure and would need to be interconnected with gas pipelines that are at least a dozen miles away from the site. Witness Swiech describes the options for gas supply interconnection and the expected costs to deliver gas to the site in more detail. Due to the need to develop new natural gas infrastructure to support a gas conversion project, the estimated annual gas transportation and storage costs are approximately $90 million per year. These costs were included in the economic analysis.

Q55. How did the Company approach the overall economic analysis of the Monroe natural gas conversion?

[7] The NEXUS pipeline has a current capacity of approximately 1.4 Bcf/day.

A55. The Company completed an economic analysis of Case 2 (i.e., conversion of Units 1 and 2 to natural gas) to compare the cost to other available alternatives. A Levelized Cost of Energy (LCOE) analysis was performed to determine the cost of the Monroe natural gas conversion in $/MWh. Based on the results of the 2025 All-Source RFP and availability of alternative firm, dispatchable resources, the LCOE of the Monroe natural gas conversion was compared to the LCOEs of gas-fired CCGTs.

Q56. What were the results of the economic analysis of the Monroe natural gas conversion compared to alternative resource types?

A56. The economic analysis determined an LCOE of $169/MWh for the Monroe natural gas conversion, which is greater than the LCOEs of the other resource types that were analyzed. Table 5 shows the LCOEs of the various resource types that were included in the Monroe natural gas conversion analysis.

Table 5 Economic Analysis Results

Resource	LCOE ($/MWh)
Monroe U1/2 Natural Gas Conversion (Case 2)	$169
CCGT	$117
CCGT w/ CCS	$149

Q57. What is the Company's recommendation regarding the potential conversion of Monroe to natural gas?

A57. Based on the factors discussed above, DTE Electric is not recommending the conversion of Monroe Power Plant to natural gas. While it is feasible to convert the units from coal-firing to natural gas-firing, the lack of available natural gas

supply at the site and costs associated with delivering gas to the site make the economics of the Monroe natural gas conversion unfavorable compared to other available generation resources. The Monroe Power Plant site is also located near an EJ community.

PART III – EMERGING TECHNOLOGY OVERVIEW

Q58. How does the Company define emerging technologies in this filing?

A58. The Company defines emerging technologies as resources that have not yet been commercialized or demonstrated at utility scale. To determine whether resources are considered emerging technologies, the Company used a modified Technology Readiness Level (TRL) framework developed by Black & Veatch (B&V). Originally established for the Company's 2022 IRP and subsequently updated, the framework assesses a technology's development stage, commercial maturity, and readiness for utility scale application.

Q59. What actions has the Company taken since the 2022 IRP to understand the advances in emerging technologies?

A59. DTE Electric continues to monitor and evaluate emerging technologies to understand their potential role in meeting future customer energy needs. As part of these efforts, the Company monitors technology cost and performance trends, benchmarks industry developments, participates in industry research and collaborative forums, and evaluates opportunities to gain understanding. In 2024, DTE Electric engaged B&V to refresh its emerging technologies assessment that was performed for the 2022 IRP. The B&V Updated Emerging Generation

Technologies Study is provided as Exhibit A-4.1 and reflects the latest information regarding technology maturity, commercialization status, and readiness level.

In addition, the Company continues to participate in industry groups such as the Electric Power Research Institute's (EPRI) Low Carbon Research Initiative (LCRI) and the Low Carbon Peer Utility Group (LCPG). Through the LCRI, the Company collaborates with other industry stakeholders to monitor technology developments, evaluate emerging research, and share lessons learned regarding low-carbon energy technologies. The LCPG, established in 2021, brings together utilities, vendors, and manufacturers to collaborate with each other and identify, prioritize, and accelerate the deployment and adoption of low carbon firm resources. Through participation in these organizations, DTE Electric gains valuable insight into technology advancement, commercialization pathways, and deployment experience, which helps inform the Company's evaluation of emerging technologies and long-term planning efforts.

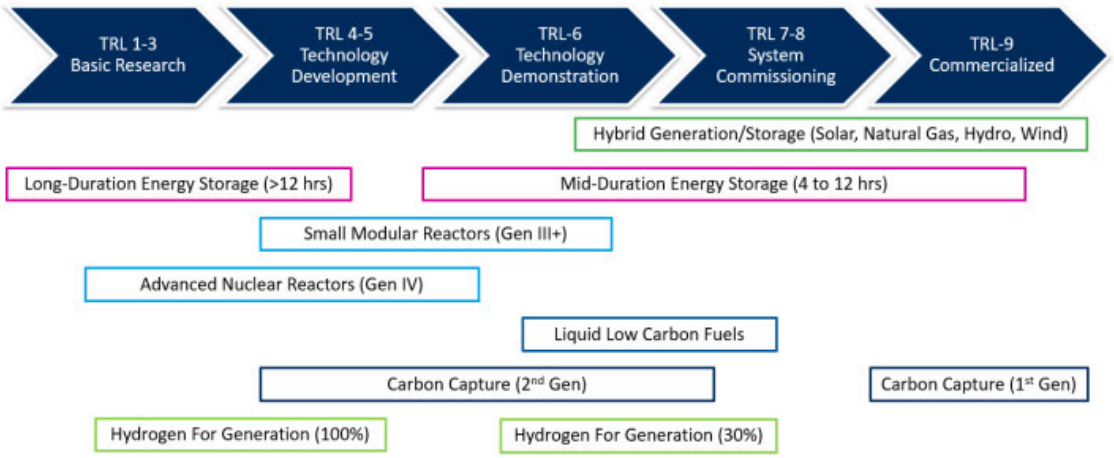
Q60. What criteria did the Company use to evaluate emerging technologies?

A60. The Company used the Updated Emerging Generation Technologies Study, which applied a modified TRL to evaluate emerging technologies and their feasibility in supporting the 2026 IRP. See Exhibit A-4.1 for the full study. The Company also considered regulatory, market, and supply-chain factors that could influence the future deployment of these technologies. Together, these criteria provide a comprehensive assessment of each technology's potential applicability within the Company's long-term resource planning process.

Q61. Please explain the technology readiness level (TRL).

A61. As described in Exhibit A-4.1, the TRL is a measurement system used to assess the maturity of a technology. This method was developed by the US National Aeronautics and Space Administration (NASA), which first defined the TRL scale in the 1970s. This concept has been used across many different industries, including the power industry. As defined by NASA "each technology project is evaluated against the parameters for each technology level and is then assigned a TRL rating based on the projects progress."[8] The TRL scale has nine categories ranging from the lowest, TRL 1, representing technologies that are in the basic research phase of development to TRL 9, representing technologies that have been commercialized and are demonstrated at utility scale. A representation of the TRL assessment is included in Figure 1 based on B&V's assessment.

Figure 1 **– TRL of Various Technologies**



[8] Tzinis, Irene. "Technology Readiness Level." NASA, https://www.nasa.gov/directorates/somd/space-communications-navigation-program/technology-readiness-levels/

Emerging technologies advance from left to right on the above chart with costs, designs, and operational data becoming more certain as technologies near a TRL of 9. The Company used this concept to classify and identify technologies to be included in IRP modeling.

Q62. Can you explain some of the key emerging technologies?

A62. Yes. Although several emerging technologies were considered in the study, descriptions of some of the key technologies are provided below. These definitions and further descriptions can be found in Exhibit A-4.1.

- **Mid-to-long-duration storage**: has four major technology categories including thermal, mechanical, chemical, and electrochemical. Based on the Updated Emerging Generation Technologies Study, mid-duration storage can be defined as technologies with durations ranging from 4 to 12 hours. Long-duration storage can be defined as technologies with duration beyond 12 hours. The MPSC's *Study of Long-Duration and Multi-Day Energy Storage* defines long-duration energy storage (LDES) as an energy storage system capable of continuously discharging electricity at its full rated capacity for more than 10 hours.[9] For further details regarding mid-to-long duration energy storage technologies, see Witness Schroeder's testimony.
- **Carbon Capture & Storage (CCS)**: a collection of technologies and processes capable of capturing CO_2 emissions from fossil fuel units such

[9] Michigan Public Service Commission, Study of Long-Duration and Multi-Day Energy Storage, Case No. U-21571, February 27, 2025, Introduction, pp. 3

as coal or gas CCGTs before transporting the captured CO_2 and storing it to prevent release into the atmosphere.

- **Small Modular Reactors (SMR)**: nuclear reactor facilities that are smaller in size than traditional nuclear power plants and that may employ multiple novel technological approaches, such as extensive use of factory-built modules and passive/inherent safety features. These types of reactors are modular in design and typically range up to 300 MW.
- **Hydrogen**: a low-carbon fuel that can be produced via numerous pathways such as water electrolysis and steam methane reforming and used for power generation, energy storage, and other industrial applications. Hydrogen can be a low-carbon fuel, as CO_2 is not a byproduct of combustion; however, hydrogen-fired generators are not currently defined as clean energy systems per MCL 460.1003.

Q63. Does the Updated Emerging Generation Technologies Study include every emerging technology?

A63. No. The Updated Emerging Generation Technologies Study does not include all emerging technologies. The emerging generation technologies in the report were selected for their ability to help DTE Electric meet carbon reduction targets, their readiness and feasibility for deployment, compliance with regulatory and policy requirements, and their economic and innovation potential. The Company used the 2022 B&V Emerging Technology report as a starting point and collaborated with B&V to develop a list of other technologies that should be considered due to development and technology advancements made since the 2022 report. Due to

more recent technology developments, the list does not include all emerging technologies such as fuel cells.

Q64. What could change the timeline for commercialization of these technologies?

A64. Federal policies such as tax credits, grants, loan guarantees, as well as research, development, demonstration, and commercial activity could affect the pace, cost, and performance of these emerging technologies. The Department of Energy (DOE) has several initiatives underway to bring down the cost and enhance the capabilities of hydrogen, long-duration storage, as well as CCS. The Inflation Reduction Act included incentives for clean energy, including hydrogen, CCS, and other emerging technologies. Subsequently, the One Big Beautiful Bill Act of 2025 (OBBBA) modified the availability and timing of certain federal clean energy tax credits. State-level clean energy and climate policies could also play a role. Another factor is the rate of implementation of these technologies by utilities and other industry players that helps drive learning and investment behavior. Witness Hajj discusses federal and state policies and their impacts on the IRP in more detail.

Q65. Does the 2026 IRP leverage emerging technologies for the benefit of customers?

A65. Yes. The Company's 2026 IRP proposed course of action (PCA) incorporates emerging technologies to provide long-term benefits for customers while balancing cost, reliability and implementation timing. The PCA includes CCGT plants with commercial operation dates (CODs) in 2031 and 2032 with capabilities for CCS in 2035. The PCA also includes 1.7 GW of LDES resources beginning in

2037, as well as 1.4 GW of hydrogen-fired CTs starting in 2043. This phased approach enables the Company to capture the benefits of commercially available technologies, while maintaining the flexibility to allow emerging technologies to further develop and commercialize before being implemented.

PART IV – LONG-TERM NUCLEAR STRATEGY

Existing Nuclear Resources

Q66. Can you provide an overview of DTE Electric's existing nuclear resources?

A66. Yes. DTE Electric operates a single nuclear resource, the Enrico Fermi Nuclear Generating Station Unit 2, or Fermi 2. Fermi 2 is an approximately 1,168 MW nuclear plant operated by DTE Electric in Newport, MI.

Q67. What is the technology design and operational history of Fermi 2?

A67. Fermi 2 is a General Electric (GE) boiling water reactor (BWR). The plant began commercial operation in 1988 and has since produced more than 200 billion kWh of power for DTE Electric customers.

Q68. How does DTE Electric operate Fermi 2?

A68. Fermi 2 operates as a baseload resource that provides reliable, carbon-free energy to DTE Electric customers 24/7. Fermi 2 originally operated on an 18-month refueling schedule; however, in 2021, the Nuclear Regulatory Commission (NRC) approved DTE Electric's request to change to a 24-month refueling cycle. Starting with the 2022 refueling outage, the plant has operated on a 24-month refueling schedule. The longer refueling schedule allows for increased efficiency, power generation, and customer value. In March 2026, Fermi 2 entered its 23rd refueling

outage (RF23) and completed its longest ever operational run – 679 consecutive days of operation. The Spring 2026 refueling outage was successfully completed after 54 days, after which Fermi 2 resumed operations.

Q69. What are the benefits of round-the-clock generation?

A69. Round-the-clock or baseload generation, such as that provided by Fermi 2, is a critical component to a diverse and well-functioning energy system. Baseload resources provide benefits during peak hours, ensuring that there are sufficient resources to supply customer demand and maintain reliability on hot summer days. Baseload resources continue to generate power during off-peak hours, allowing for more expensive and less efficient resources to be idled. When intermittent resources are not operating, baseload resources and other dispatchable resources ensure that supply continues to meet customer demand.

Q70. What reliability benefits does Fermi 2 provide?

A70. Fermi 2 provides significant reliability and capacity benefits for DTE Electric and its customers. The baseload, reliable operation of Fermi 2 results in high accreditation in MISO's capacity market. For the 2026/27 capacity planning year, Fermi 2 was accredited for 955.7 MW of MISO Zone 7 summer capacity. Fermi 2 comprises approximately 10% of DTE Electric's current total system capacity.

Q71. What are the customer affordability benefits associated with Fermi 2?

A71. DTE Electric receives capacity and energy revenue in the MISO wholesale markets related to the operation of Fermi 2. Given Fermi 2's baseload and reliable operation, Fermi 2 receives high capacity accreditation and generates more energy

than any other DTE Electric generation resource. These capacity and energy revenues are credited to PSCR expense, reducing the overall cost to DTE Electric's customers.

Q72. Does Fermi 2 generate clean power?

A72. Yes. Fermi 2 generates clean power and meets the definition of a clean energy system under MCL 460.1003(i)(i). The clean power generated by Fermi 2 will support compliance with Michigan's Clean Energy Standard.

Q73. Does Fermi 2 have an impact on the local community?

A73. Yes. Fermi 2 has a positive impact on the local Newport and Monroe County communities. The plant is one of Monroe County's largest employers, providing approximately 750 reliable and well-paying jobs. DTE Electric has a long-standing partnership with the Monroe County Community College (MCCC) focused on nuclear-industry workforce development, including the creation of MCCC's Nuclear Engineering Technology program in 2011.

Q74. Is Fermi 2 licensed by the NRC?

A74. Yes. The Fermi 2 Operating License (OL) was first issued by the NRC under 10 CFR Part 50 in March 1985. The original 40-year license continued through March 2025. In 2014, DTE Electric applied for a 20-year renewal of the license under 10 CFR Part 54, and the NRC issued a license renewal in 2016. The current Fermi 2 license continues through March 2045.

Q75. Can DTE Electric further extend the Fermi 2 operating license?

A75. Yes. Under 10 CFR Part 54, the NRC can issue up to two 20-year license renewals, for a total operational life of 80 years. A second license renewal for Fermi 2 would result in the license continuing through 2065. While DTE Electric has not yet sought a second license renewal and will not need to seek that application for some time, Fermi 2 is expected to remain a long-term source of reliable and clean power for DTE Electric's customers. Fermi 2 is expected to continue operations throughout the twenty-year study period for the 2026 IRP.

Nuclear Industry & Technology Developments

Q76. What is the current state of the U.S. nuclear industry?

A76. Nuclear power continues to be a significant and key source of power generation in the U.S., generating nearly 20% of domestic power needs. While very limited new nuclear capacity has been added in recent decades, the existing fleet of approximately 100 commercial nuclear power reactors remain in operation. Several plants retired in the 2010s and early 2020s due to challenging market conditions; however, some of those are now pursuing restarts amidst increased demand in recent years. Design and development of advanced reactor designs have continued, including Gen III+ and Gen IV designs with enhanced passive safety features. While development of large reactors (generally greater than 1,000 MW) continues, recent industry development has focused on SMRs, which are intended to be smaller units (generally less than 300 MW) that employ factory construction and modular installation techniques to reduce cost.

Q77. What new nuclear capacity has been added in recent decades?

A77. Only three new nuclear units have been added in the U.S. since the late 1990s – Watts Bar Unit 2 and Vogtle Units 3 and 4.

Watts Bar 2 is an approximately 1,150 MW pressurized water reactor (PWR) operated by Tennessee Valley Authority (TVA) in Tennessee. Watts Bar 2 construction originally started in 1972 but was suspended in 1985 due to decreased demand. In 2007, TVA announced its intent to restart construction. After several design modifications, the unit went into service in 2016.

Vogtle 3 and 4 are two approximately 1,117 MW AP1000 PWR reactors designed by Westinghouse and operated by Southern Company in Georgia. The Vogtle units are the first and only Gen III+ design with passive cooling features that have been deployed in the United States. Southern Company applied for a combined construction and operating license in 2008 that was approved by the NRC in 2012. After construction began in 2013, the project experienced several delays before being put in service in 2023 (Unit 3) and 2024 (Unit 4). The cost of the project reportedly exceeded $36 billion[10] (>$16,000/kW).

Q78. Were there other new nuclear plants that were planned in the 2000s and 2010s?

A78. Yes. There were several new nuclear plants in the U.S. that were planned in the 2000s and 2010s that were later canceled or have not yet been developed. South Texas Project Units 3 & 4 (TX), Levy County Units 1 & 2 (FL), Lee Units 1 & 2 (SC), North Anna Unit 3 (VA), and DTE Electric's own Fermi 3 (MI) were

[10] NAVETRA Casebook, *Vogtle Nuclear Capital Risk*. https://www.purplewins.io/article/vogtle-nuclear-capital-risk. Accessed September 9, 2026.

licensed by the NRC but not developed. Applications were submitted to the NRC but not completed for Turkey Point Units 6 & 7 (FL), Harris Units 2 & 3 (NC), and Comanche Peak Units 3 & 4 (TX). SCANA/SCE&G were issued a combined license for the V.C. Summer Units 2 & 3 (SC) in 2012, also Westinghouse AP1000 units. After construction began in 2013, the project was later suspended in 2017.

Q79. Why was other planned new nuclear capacity not built?

A79. Several factors adversely impacted the development of nuclear projects, resulting in cancellations and suspensions. The Fukushima nuclear incident in Fukushima, Japan, in March 2011 impacted public sentiment of nuclear safety and resulted in increased regulatory and safety burden to construct and operate nuclear plants in the United States. Nuclear power also faced increased competition from the development of renewables and natural gas resources. The shale gas revolution in the U.S. has resulted in abundant and affordable natural gas supplies as domestic production has increased from 19 Tcf in 2005 to 43 Tcf in 2025.[11] Meanwhile, the up-front capital cost risks associated with nuclear have been exacerbated by supplier challenges, cost overruns, and schedule delays experienced at the Vogtle and Summer projects.

Q80. Have existing nuclear plants continued to operate in recent years?

A80. Yes. Most of the nuclear units operating in 2010 in the U.S. have continued operating, while about a dozen units have retired. More than 20 units, including Fermi 2, have applied for a license extension since 2010.

[11] https://www.eia.gov/dnav/ng/hist/n9050us2a.htm

Q81. What nuclear plants have retired, and why did they retire?

A81. Since 2010, several nuclear plants have retired including Kewaunee (WI), San Onofre Units 2 & 3 (CA), Crystal River Unit 3 (FL), Vermont Yankee (VT), Fort Calhoun (NE), Oyster Creek (NJ), Pilgrim (MA), Three Mile Island Unit 1 (PA), Duane Arnold (IA), Indian Point Unit 2 & 3 (NY), and Palisades (MI). These plants primarily retired due to low power prices caused by increased competition from renewables and natural gas, while some retired due to equipment failures.

Q82. How has demand for nuclear power shifted in the past few years?

A82. In the past five years, there has been a material resurgence in demand along with interest in nuclear power. Increasing decarbonization needs and clean energy mandates, such as Michigan's 2023 energy legislation, have increased demand for nuclear power as a clean energy resource. The Biden Administration's Inflation Reduction Act (IRA) of 2022 included production tax credits (PTCs) for existing nuclear plants and PTCs or investment tax credits (ITCs) for new nuclear plants. The U.S. DOE has offered significant nuclear energy grants, including the $900 million Gen III+ SMR grant. Lastly, increased power demand, particularly from artificial intelligence (AI) and data centers, has increased demand for and investment in nuclear power.

Q83. Which retired nuclear plants have announced plans to restart?

A83. At this time, at least three retired nuclear plants have announced plans to restart – Palisades (MI), Three Mile Island Unit 1 (PA), and Duane Arnold (IA).[12]

[12] U.S. Nuclear Regulatory Commission, *Palisades Nuclear Plant*; Constellation Energy, *Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to the Grid*, September 20, 2024; NextEra Energy, *NextEra Energy and Google Announce New Collaboration to Accelerate Nuclear Energy Deployment in the U.S.*, October 27, 2025. Accessed August 31, 2026.

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The Palisades plant, located in Van Buren County, MI, was retired in 2022. Shortly after retirement, Entergy sold the plant to Holtec International for decommissioning.[13] In 2023, Holtec began pursuing NRC approvals to return the plant to operational status.[14] Holtec later secured a $1.52 billion federal loan in 2024.[15] In August 2026, the process to load nuclear fuel into the plant's reactor vessel began,[16] putting Palisades on track to be the first shuttered commercial nuclear power plant to be returned to active power generation in the United States.

In September 2024, Constellation announced plans to reopen Three Mile Island Unit 1 in 2028 after its 2019 retirement. Constellation entered into a 20-year power purchase agreement (PPA) with Microsoft and expects to invest approximately $1.6 billion in the restart.[17] In 2025, DOE closed a $1 billion federal loan to help finance the restart.[18]

In 2025, NextEra and Google announced plans to restart the Duane Arnold plant, which retired in 2020. The plant is targeted to return to service by the first quarter

[13] Entergy, *Entergy Completes Sale of Palisades Power Plant to Holtec*, June 28, 2022. https://www.entergy.com/news/entergy-completes-sale-palisades-power-plant-holtec. Accessed August 31, 2026.
[14] U.S. Nuclear Regulatory Commission, *Palisades Nuclear Plant*. https://www.nrc.gov/info-finder/reactors/pali. Accessed August 31, 2026.
[15] Holtec International, *Holtec Closes $1.52B DOE Loan to Restart Palisades, Support Revitalization of Domestic Nuclear Industry*, September 30, 2024. https://holtecinternational.com/hh-39-17/. Accessed August 31, 2026.
[16] Holtec International, *Palisades Begins the Process for Loading Fuel in its Reactor Vessel, Embarking on a Meticulous Progression to Restart: Holtec's Finest Hour*, Holtec Highlights No. 41.17, August 30, 2026. https://holtecinternational.com/wp-content/uploads/2026/08/HH-41.17.pdf. Accessed August 31, 2026.
[17] Constellation Energy, *Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to the Grid*, September 20, 2024. https://www.constellationenergy.com/news/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html. Accessed August 31, 2026.
[18] U.S. Department of Energy, *Energy Department Closes Loan to Restart Nuclear Power Plant in Pennsylvania*, November 18, 2025. https://www.energy.gov/articles/energy-department-closes-loan-restart-nuclear-power-plant-pennsylvania. Accessed August 31, 2026.

of 2029, subject to regulatory approvals, and Google entered into a 25-year agreement to purchase energy from the facility.[19] In September 2026, DOE closed a $1.9 billion federal loan to help finance the restart.[20]

Q84. What new reactor designs are being developed?

A84. New nuclear designs can be split into three categories – large Gen III+ designs, Gen III+ SMRs, and Gen IV SMRs. While various large Gen III+ designs have been certified by the NRC including the ESBWR (GE-Hitachi) and APR-1400 (Korea Electric Power), the AP1000 (Westinghouse) is the only large Gen III+ design with a deployment history in the U.S.

Q85. What are SMRs?

A85. SMRs, or small modular reactors, are smaller (generally <300 MW) reactor designs that intend to employ factory construction and modular installation techniques to reduce costs. The smaller size of SMRs allows for lower capital cost and financing requirements compared to large reactors. Factory construction and modular installation techniques are intended to achieve cost reductions from scaled production and reduce on-site construction costs. See Exhibit A-4.1 for additional details related to SMRs.

Q86. What is the difference between Gen III+ and Gen IV reactor designs?

[19] NextEra Energy, *NextEra Energy and Google Announce New Collaboration to Accelerate Nuclear Energy Deployment in the U.S.*, October 27, 2025. https://www.investor.nexteraenergy.com/news-and-events/news-releases/2025/10-27-2025-203948689. Accessed August 31, 2026.
[20] U.S. Department of Energy, *Energy Department Closes $1.9 Billion Loan to Restart Duane Arnold Nuclear Plant*, September 8, 2026. https://www.energy.gov/articles/energy-department-closes-19-billion-loan-restart-duane-arnold-nuclear-plant. Accessed September 9, 2026.

A86. Gen III+ reactors are generally light-water designs, meaning that water acts as both the coolant and the neutron moderator to facilitate fission. These reactors utilize low-enriched uranium (LEU) for fuel and offer enhanced passive cooling safety systems compared to earlier light-water designs. Gen III+ designs include the GE Vernova Hitachi BWRX-300, Westinghouse AP300, and Holtec SMR-300.

Gen IV reactors include newer technologies that generally utilize alternative coolants other than water. Gen IV designs have inherent safety features and improved efficiency; however, these technologies have not yet been commercially demonstrated for utility-scale power generation. Gen IV reactor technologies include sodium-cooled fast reactors such as the TerraPower Natrium design. These reactors utilize liquid sodium as the coolant, allowing for high-temperature, low-pressure operation. Another Gen IV reactor technology is the high-temperature gas-cooled reactor, such as the X-energy Xe-100 design. These reactors utilize helium coolant and graphite moderation, allowing for increased efficiency through high-temperature operation.

Q87. What new utility-scale nuclear projects are planned or in progress?

A87. Several new utility-scale nuclear projects have recently begun development in the United States. TVA received approval from the NRC for an early site permit at its Clinch River (TN) site in 2019 and later announced its intent to develop a SMR project at the site. TVA intends to utilize the BWRX-300 design for the project, with a targeted commercial operation date (COD) in the early 2030s. In late 2025, the DOE announced a $400 million grant to advance the Clinch River project and the BWRX-300 design. Holtec announced its intent to deploy two of its Holtec-

designed SMR-300 reactors at the Palisades site in Michigan, which are targeting a COD in the early 2030s. Holtec also received a $400 million grant from DOE to support the Palisades SMR project and SMR-300 design.

Projects utilizing the BWRX-300 design are also being developed in Canada. Ontario Power Generation (OPG) is deploying the BWRX-300 at its Darlington Nuclear Generating Site, planning a four-unit deployment totaling 1,200 MW. Construction began in 2025, and the first unit is expected to reach COD in 2030 with the remaining units coming online by the mid-2030s.

From a Gen IV standpoint, TerraPower is deploying its Natrium technology at its 345 MW Kemmerer project (WY). The Kemmerer construction permit was approved by the NRC in March 2026, with nuclear construction commencing shortly thereafter. COD for the Kemmerer project is targeted for the early 2030s.

DTE Electric's New Nuclear Resource Opportunities

Q88. Has DTE Electric evaluated opportunities for new nuclear capacity?

A88. Yes, DTE Electric has identified and evaluated several opportunities for new nuclear capacity and continues to consider nuclear for its generation portfolio as a clean, baseload generation resource. The Company has identified an opportunity to implement an EPU at its Fermi 2 plant that would increase its generation capacity. The Company also continues to hold a combined license for the Fermi 3 project, which provides optionality for future nuclear projects at the Fermi site. DTE Electric is continuing to evaluate advanced large nuclear and SMR technologies for potential deployment at its existing generation sites.

Q89. What is the Fermi 2 EPU project?

A89. The Fermi 2 EPU project is a potential project to increase the capacity of the existing Fermi 2 plant by up to 177 MW. The EPU process involves a series of system and equipment upgrades to allow for increased steam flow, increasing power generation. Based on initial estimates, the Fermi 2 EPU project is expected to cost approximately $1.0 billion ($5,700/kW).

Q90. What system and equipment upgrades typically comprise an EPU for a BWR like Fermi 2?

A90. An EPU generally involves modifications to turbine and generator equipment and other balance of plant systems necessary to support increased thermal output and power generation. For BWRs, typical modifications may include replacement or upgrades of the high- and low-pressure turbines, generator rotor, main transformers, steam dryer, steam lines and relief valves, condensate and feedwater pumps, feedwater heaters, and other components.

Q91. Have other operating plants implemented EPUs?

A91. Yes. The majority of operating BWRs have implemented EPUs, with others announced or in progress. EPUs are a well-established process to increase the power generation and value of existing nuclear resources. The NRC has an established process for EPUs, requiring license amendments under 10 CFR Part 50.

Q92. Why have DTE Electric and other nuclear operators evaluated EPUs?

A92. EPUs provide an opportunity to increase the capacity and generation of an existing nuclear resource, leveraging existing infrastructure and operational expertise. The capital costs to implement an EPU are generally lower than the capital costs to develop new nuclear projects on a $/kW basis. The operating costs are also generally less than new nuclear projects as much of the operations and maintenance work is comparable to the required work prior to an EPU. Overall, EPUs are an efficient and practical way to add reliable and clean generation capacity by maximizing the value and production of existing resources.

Q93. Are EPU projects eligible for federal tax credits?

A93. Yes. EPU projects, including the Fermi 2 EPU project, are eligible for federal tax credits that were established under the IRA. Section 45Y is the Clean Electricity Production Tax Credit, a technology-neutral PTC for electricity generated with no greenhouse gas emissions. Section 48E is the comparable Clean Energy Investment Tax Credit, which has similar requirements but provides an ITC rather than a PTC. Qualifying projects can claim either PTCs under Section 45Y or ITCs under Section 48E, but not both. If the Fermi 2 EPU project is implemented, DTE Electric would intend to claim federal tax credits to offset project costs, reducing costs to customers.

Q94. When could an EPU at Fermi 2 be implemented?

A94. Due to engineering, procurement, outage planning, and licensing requirements, implementation of a Fermi 2 EPU would take several years. For the purposes of the 2026 IRP, a potential Fermi 2 EPU is assumed to be feasible for commercial operation starting in 2036. Implementation during the planned 2036 refueling

outage would require project development starting this year, including a detailed scoping study to further evaluate the project.

Q95. Has DTE Electric previously requested MPSC approval of the Fermi 2 EPU project?

A95. No, DTE Electric has not previously requested MPSC approval of the Fermi 2 EPU project itself. However, in the Company's 2020 Electric Rate Case (Case No. U-20836) and 2023 Electric Rate Case (Case No. U-21297), the Company requested cost recovery for a potential Fermi 2 EPU study in the amount of approximately $4.9 million. In both cases, the Commission disallowed the requested study costs.

In U-21297, the Commission adopted the Administrative Law Judge's recommendation to disallow the request, noting that DTE Electric had not specified the EPU study expenses for 2025 and 2026 and had not sufficiently addressed the Attorney General's concerns regarding whether a potential EPU would be economic compared to other sources of capacity. While insufficient information was provided in U-21297 to allow for approval, the Commission did not find that the EPU project was imprudent and the Order did not constitute a denial of a request to approve the Fermi 2 EPU project itself.

Q96. Was the Fermi 2 EPU selected in DTE Electric's 2026 IRP PCA?

A96. Yes. As described in more detail by Witness Manning, the Company completed extensive modeling to determine the PCA. The 177 MW Fermi 2 EPU project was selected in EnCompass modeling in 2036 as an economic resource in the

Company's PCA. The Fermi 2 EPU provides reliable, baseload generation that supports resource adequacy and generates clean energy that contributes to DTE Electric's clean energy portfolio.

Q97. What is the timeline and implementation plan for the Fermi 2 EPU?

A97. As described above, the Fermi 2 EPU was selected in the PCA in 2036. The planned COD in 2036 is reasonable given the significant scoping, engineering, procurement, site preparation, licensing, construction, installation, and commissioning work required to implement an EPU. The timeline for implementing the Fermi 2 EPU with a 2036 COD includes:

- 2026-27 – Completion of Scoping Study
- 2027-29 – Level 2 Engineering
- 2027-35 – Equipment Procurement
- 2029-32 – NRC Licensing
- 2029-33 – Detailed Engineering & Site Preparation
- 2032-36 – Construction & Implementation

Q98. What is the status of the scoping studies for the Fermi 2 EPU?

A98. DTE Electric is preparing to launch a first phase of scoping studies in 2026 that are expected to be completed in 2027. The scoping studies will confirm project feasibility and allow for the project to proceed to level 2 engineering and long-lead procurement. DTE Electric is exploring federal support to fund this first phase of studies.

Q99. What work is necessary to complete Level 2 engineering?

A99. Level 2 engineering, which is expected to begin in 2027 and be completed in 2029, progresses project engineering in advance of detailed engineering and licensing work, including detailed scheduling, cost estimates, and risk identification. The Company would coordinate with a nuclear Engineering, Procurement, and Construction (EPC) firm to complete Level 2 engineering work.

Q100. Why does equipment procurement need to begin in 2027?

A100. Several components required to implement an EPU are long-lead components that require orders to be placed in 2027 to support a 2036 COD. Significant long-lead components may include low-pressure turbine and steam dryer equipment. Procurement for other EPU and balance of plant equipment will continue throughout the project period.

Q101. What NRC licensing is required to implement an EPU?

A101. To license the Fermi 2 EPU, DTE Electric would develop and submit a License Amendment Request (LAR) to the NRC under 10 CFR Part 50. Development of the LAR would begin in 2029 with an expected submittal in 2030. NRC review and approval is anticipated to be completed by 2032.

Q102. What additional work can be completed prior to NRC licensing approval?

A102. Detailed engineering and site preparation work would begin in 2029 and continue through NRC licensing approval. Site preparation work may include clearing, grading, development of laydown areas and access roads, installing temporary construction facilities, and material staging. Additionally, non-safety-related

construction of balance of plant systems that do not require prior NRC approval would occur during this period.

Q103. What is the timeline for the EPU construction and implementation after the licensing approval?

A103. Construction, implementation, and commissioning are expected to begin in 2032 and continue through project COD in 2036. To mitigate the impact on Fermi 2 operations during this period and to manage the work involved with an EPU, project implementation is expected to occur during both the scheduled Spring 2034 refueling outage (RF27) and the Spring 2036 refueling outage (RF28). Following final commissioning during RF28, the Fermi 2 EPU project will be completed, providing 177 MW of additional clean, reliable, baseload generation capacity.

Q104. What approvals related to the Fermi 2 EPU is DTE Electric seeking from the Commission in this case?

A104. DTE Electric is seeking approval of its 2026 IRP PCA, which includes the Fermi 2 EPU project with an expected 2036 COD. However, the Company is not seeking any specific cost approvals for the Fermi 2 EPU project in this case. If the 2026 IRP PCA is approved and the scoping study confirms project feasibility, DTE Electric would seek cost approvals related to the Fermi 2 EPU in a future regulatory proceeding as the project progresses.

Q105. What is the Fermi 3 project?

A105. Fermi 3 is a potential project to construct an additional new nuclear unit at the Fermi site. As licensed, Fermi 3 is an approximately 1,550 MW plant utilizing GE

Hitachi's Gen III+ ESBWR design. DTE Electric submitted an application for a combined license under 10 CFR Part 52 in 2008. The NRC later issued the combined license in 2015. The Fermi 3 project has not been developed; however, DTE Electric continues to hold and maintain the Fermi 3 license.

Q106. Does DTE Electric have plans to develop the Fermi 3 project?

A106. At this time, there are no plans to develop the Fermi 3 project as originally contemplated. While the ESBWR design was licensed by the NRC, GE Hitachi did not complete detailed engineering design after projects in development were suspended, and no ESBWR units have been constructed worldwide. GE Vernova Hitachi's recent nuclear development efforts have focused on the BWRX-300 SMR design rather than the large ESBWR design. As a result, DTE Electric is unlikely to construct an ESBWR at the Fermi site.

Q107. Does the Fermi 3 combined license provide value in the event that DTE Electric pursues nuclear projects at the Fermi site?

A107. Yes. The Fermi 3 combined license remains a valuable asset to support potential new nuclear projects at the Fermi site. Considerable site-specific engineering and environmental assessments were completed to support the Fermi 3 combined license, which remain valid and applicable for other new nuclear projects at the site. While additional design-specific evaluations and engineering would be required, DTE Electric could seek to amend the Fermi 3 license to utilize an alternative reactor design or otherwise leverage the underlying evaluations to support a new project. While the Company is not actively pursuing any alternative

projects, it continues to evaluate new nuclear options and intends to maintain the Fermi 3 combined license to support future opportunities.

Q108. What potential new nuclear projects has DTE Electric evaluated for deployment at Fermi or other sites?

A108. DTE Electric has evaluated new large nuclear and SMR technologies for potential deployment at its sites. From a large nuclear standpoint, the Westinghouse AP1000 design is the most demonstrated and deployable design. While DTE Electric has not formally evaluated the AP1000 design, it is likely that an AP1000 could be deployed at the Fermi site. DTE Electric has completed preliminary studies that indicate that various SMR designs could be deployed at the Fermi site. DTE Electric commissioned a study from B&V that found that various SMR designs could be deployed at the Fermi site. B&V also provided engineering support for the Fermi 3 Combined Operating License Application (COLA) and is familiar with the Fermi site. The B&V Fermi SMR feasibility study is provided as Exhibit A-4.2. Nuclear resources are also an option for future deployment at other DTE Electric sites.

Q109. Is new nuclear capacity a feasible option for replacement of the retiring Monroe Power Plant Units 1 and 2 in 2032?

A109. No. New nuclear capacity that is not presently in development is not a feasible option for replacement of the retiring Monroe Power Plant Units 1 and 2 in 2032. Given the associated engineering, procurement, licensing, and construction requirements, it is unlikely that a new nuclear asset could be placed in service by 2032. Furthermore, DTE Electric did not receive any new nuclear bids in the 2025

All-Source RFP that met the RFP minimum requirements. For modeling purposes for this IRP, new nuclear resources are assumed to be available for operation starting in 2034.

Q110. Are any new nuclear resources included in the PCA other than the Fermi 2 EPU?

A110. No. There are no large nuclear or SMR resources included in the Company's 2026 IRP PCA. These resources were not selected in the EnCompass modeling, primarily due to their high capital costs, which make them less economical than other resources. Although new nuclear resources are not included in the PCA for this IRP, the Company intends to closely track new nuclear projects industry-wide as technologies continue to develop and projects are implemented. If capital costs improve as projects are developed, new nuclear resources may become economical and prudent as part of DTE Electric's future clean, diverse, and reliable generation portfolio.

PART V – 2025 ALL-SOURCE RFP PROCESS AND RESULTS

Overview and Purpose

Q111. Did the Company conduct an RFP for resources prior to the 2026 IRP?

A111. Yes. The Company conducted an All-Source RFP in 2025 to procure replacement resources for the Monroe Power Plant after its full retirement in 2032, as previously identified in DTE Electric's 2022 IRP. The 2025 All-Source RFP allowed DTE Electric to study and consider a range of possible technologies to replace the retiring Monroe Power Plant units, consistent with the 2022 IRP Settlement Agreement in Case No. U-21193.

Q112. Can you provide an overview of the RFP?

A112. Yes. In addition to the need to replace the capacity of the Monroe Power Plant, the 2025 All-Source RFP accounts for MISO's direct loss of load (DLOL) seasonal construct as described by Witness Burgdorf and accounts for forecasted demand. The RFP sought between 1,500 and 3,000 MW of firm MISO-accredited capacity and energy from energy storage systems and clean energy systems as defined in MCL 460.1003(i). DTE Electric accepted contract structures in the form of build transfer agreements (BTAs), purchase and sale agreements (PSAs), tolling agreements (TAs), or power purchase agreements (PPAs) with a COD between January 1, 2030, and December 31, 2032. The RFP allowed for proposals of sizes smaller than the total capacity need such that a combination of projects could be considered. In addition, the RFP stated that the Company has the discretion to take additional projects above the threshold should further modeling or analyses demonstrate additional resources are needed to account for changes in the planning environment, including load growth and changes to MISO's reliability planning process or capacity accreditation methodology.

Q113. How did the RFP design consider proximity to the Monroe Power Plant?

A113. The RFP was designed to replace the capacity and energy of the Monroe Power Plant by seeking replacement resources before the Monroe Power Plant retired. This ensures that the resources will be operational before the last two units of the Monroe Power Plant retire in 2032. In addition, the RFP recognized that projects that were "located electrically near the Monroe Power Plant may provide additional benefits that will be considered in the evaluation."

Q114. How was the RFP designed to account for MISO's DLOL seasonal construct?

A114. As noted above, the Company accounted for MISO's DLOL seasonal construct by seeking capacity beyond the approximately 1,500 MW needed to replace the Monroe Power Plant and allowing for a range of capacity up to 3,000 MW. The Company also used the known MISO DLOL assumptions at the time of evaluation and during modeling of the 2026 IRP PCA.

Q115. How did anticipated load growth, including large customer additions, factor into the design of the RFP?

A115. As noted above, the Company accounted for load growth in the RFP by seeking capacity beyond the approximately 1,500 MW needed to replace the Monroe Power Plant and allowing for a range of capacity up to 3,000 MW from one or more resources. This expanded capacity range provided flexibility to account for additional load growth between issuing the RFP and confirming the resources needed through IRP modeling for the 2026 IRP process.

Compliance with Statutory, Regulatory, and Guidelines

Q116. What statutory and regulatory requirements, as well as applicable Commission guidelines, applied to the RFP?

A116. Several statutory and regulatory requirements as well as Commission guidelines applied to this RFP including:

- Case Nos. U-21570 and U-21867 IRP filing requirements regarding the Pre-filing RFPs
- Case No. U-20852 MPSC's Competitive Procurement Guidelines

- MCL 460.6t (6), (11), and (12) as described by Witness Hajj for the approval of resources
- MCL 460.6s as described by Witness Hajj for the approval of resources

Q117. What steps did the Company take to ensure compliance with applicable state, federal, and Commission rules?

A117. The Company hired an Independent Monitor (IM) to ensure the RFP and the Company complied with all applicable state, federal, and Commission rules that were applicable to the competitive procurement solicitations. The Company also leveraged existing processes and expertise to ensure all applicable procurement requirements were incorporated into the solicitation.

Q118. What are the Pre-filing RFP requirements in Case Nos. U-21570 andU-21867?

A118. Per Case Nos. U-21570 and U-21867, an electric utility must issue an RFP for any new supply-side capacity resources needed to meet projected load, planning reserve margin, and local clearing requirements during the initial three-year IRP planning period. Specifically, the requirements state that "the utility shall comply with the following:

a) The utility shall include documentation demonstrating that the RFP process was completed with the IRP application;
b) The utility's RFP process is subject to audit by the Staff;
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the Commission's code of conduct,

and applicable state, federal, and Commission rules, and any adherence with the competitive procurement guidance in Case No. U-20852;

d) The RFP shall allow for proposals of sizes smaller than the total capacity need such that a combination of projects is needed, including but not limited to distribution connected resources, to provide new supply-side capacity, pursuant to MCL 460.6t(6); and

e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a PPA for a period that is the lesser of the study period or the useful life of the resource type proposed."

Q119. Did the 2025 All-Source RFP comply with the Pre-filing RFP requirements as described in Case Nos. U-21570 and U-21867?

A119. Yes. Witness Hajj provides details on how the Company complied with Case Nos. U-21570 and U-21867 requirements in her testimony and in Exhibit A-1 DTE Electric IRP Application Requirements Cross Reference Table.

Q120. What are the Competitive Procurement Guidelines in U-20852?

A120. The Competitive Procurement Guidelines were established in 2021 by the MPSC in Case No. U-20852 and provide a standardized framework for rate-regulated electric utilities in Michigan to procure new energy and capacity resources through a transparent, technology-neutral solicitation process designed to ensure a fair, competitive, and cost-effective process. The Guidelines are to be used by both the utility when conducting a competitive procurement process and by the Commission during the review of the process to "ensure strong, ownership-neutral

market response and value for customers through transparency, non-discriminatory access, certainty, and fairness in the bidding process."

The Guidelines provide a framework for utilities to apply to their RFP processes that include utilities having independent oversight or administration of the RFP, hosting stakeholder meetings to solicit feedback on the RFP materials, establishing protections between utility self-build bid and evaluation teams, among other things. The Guidelines state that when these are used by the utilities, "it is presumed that resulting projects and contracts are reasonable and prudent."

Q121. Did the RFP comply with the Competitive Procurement Guidelines in Case No. U-20852?

A121. Yes. The Company abided by the Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PURPA Compliance) as defined in Case No. U-20852. The Company incorporated all the Guidelines into the RFP process and hired Charles River Associates (CRA) as the IM to ensure the Guidelines were addressed and to provide oversight of the process. See Exhibit A-4.3 – 2025 All-Source RFP IM Report for a description by the IM on how the Company abided by and applied the Guidelines to the RFP. See Exhibit A-4.4 – Alignment with the Competitive Procurement Guidelines for a description of how each Guideline was addressed in the RFP.

Q122. How does the Company's procurement strategy address the labor standards identified in the IRP filing requirements as defined in Case Nos. U-21570 and U-21867?

A122. The Company conducts applicable competitive procurements in accordance with the Commission-approved Competitive Procurement Guidelines in Case No. U-20852. As part of those procurements, the Company evaluates non-price factors, including applicable labor considerations as defined in MCL 460.6t(8)(c), and will structure the procurement and contracting process to address the labor standards applicable to construction or investment in new or existing capacity resources included in the Company's implementation of the IRP.

Q123. Were any material violations, breaches, or non-compliance issues identified during the RFP process?

A123. No. The Company did not have any material violations, breaches, or non-compliance issues throughout the RFP process. See Exhibit A-4.3 for the IM's independent assessment of the All-Source RFP.

Independent Monitor

Q124. Do the Competitive Procurement Guidelines allow for the use of an IM in competitive procurement solicitations?

A124. Yes. In Case No. U-20852, the Competitive Procurement Guidelines state that a utility should use an IM or Independent Administrator (IA) when procuring resources, including utility self-build projects. If a utility uses an IM rather than an IA, it should provide an explanation to Commission Staff explaining the reasons for an IA not being used and how compliance with any applicable FERC guidelines was ensured.

Q125. Why did the Company elect to use an IM instead of an IA?

A125. An IM provides independent oversight and support while the utility retains responsibility for those aspects of the solicitation not assigned to the IM, including non-pricing evaluation and making final selections. By comparison, an IA administers the solicitation and has final responsibility for evaluating and scoring proposals. The Company elected to use an IM because it had the internal expertise in resource evaluation, system planning, and RFP administration necessary to support the development and evaluation of the 2025 All-Source RFP.

The IM structure allowed the Company to use that internal expertise while obtaining independent oversight and support throughout the RFP process. As described below, the IM reviewed and provided input on the RFP design, monitored the solicitation and firewall protections, led stakeholder and bidder communications, supported the eligibility and threshold evaluation, performed the pricing evaluation, reviewed the Company's non-pricing evaluation, provided recommendations to promote consistency, and oversaw the RFP process through shortlisting. The Company retained responsibility for the detailed non-pricing evaluation and for making the final project selections.

This allocation of responsibilities provided independent oversight while preserving the Company's ability to apply its system-specific expertise and retain responsibility for the resource selection decisions incorporated into its 2026 IRP. The respective responsibilities of the Company and the IM are described below and in Exhibit A-4.3.

Q126. How did the Company use the IM in the RFP process?

A126. The Company engaged the IM before developing the RFP to ensure the entire RFP process was conducted in a fair and transparent manner. In addition, the Company worked closely with the IM to help define and develop the RFP using the IM's experience overseeing similar procurements across the industry. For this RFP, the IM led the stakeholder engagement process in coordination with the Company and led all external communication regarding the RFP from the initial stakeholder engagement announcement to shortlist notifications. The Company only interacted directly with stakeholders during public events or meetings with the IM and stakeholders. Together, the IM and the Company defined the minimum eligibility criteria, RFP schedule, and other key aspects of the RFP as discussed in my testimony. The IM also developed the pricing evaluation tool and was responsible for that portion of the evaluation. In addition, the IM participated in all scoring discussions, providing guidance as needed. Using an IM throughout the process allowed the Company to balance transparency and fairness while maintaining the flexibility needed to tailor the procurement to meet the Company's needs as it developed its 2026 IRP.

Q127. Why did the Company select CRA to serve as the IM?

A127. The Company selected CRA to serve as the IM for several reasons including:

- Having a clear and comprehensive understanding of the responsibilities needed to support the RFP;
- Extensive experience serving as an Independent Monitor, Evaluator, and/or Administrator across comparable procurement opportunities;

- Strong analytical capabilities, including their experience with evaluating emerging technologies and navigating the complexities of comparing diverse resource types;
- A clear understanding of economic evaluation methodologies and readiness to support the Company's bid evaluation process; and
- Deep market awareness, including familiarity with current challenges and considerations related to emerging technologies from RFPs issued throughout the country.

Q128. Can you describe the roles and responsibilities of the IM?

A128. The roles and responsibilities of the IM included:

Table 6 IM and Company Responsibilities

Category	IM Responsibilities	Company Responsibilities
RFP Oversight & Guideline Compliance	Provide oversight of the RFP to ensure adherence to the Competitive Procurement Guidelines	Lead the RFP development and compliance with all applicable requirements and guidelines
Solicitation Monitoring	Monitor all aspects of the RFP solicitation process, from RFP development through shortlisting and final selections to ensure a fair process	Share information with the IM
RFP Design & Evaluation Framework	Review and provide feedback on RFP design and development, including minimum eligibility requirements and evaluation criteria	Develop and design the RFP and incorporate feedback from IM
Firewall Oversight	Oversee the 2025 All-Source RFP firewall to support a fair and impartial solicitation process	Manage the firewall process including issuing acknowledgment forms, maintaining firewall roster, and

Category	IM Responsibilities	Company Responsibilities
		communicating changes to the roster
Stakeholder & Bidder Communications	Lead and manage stakeholder outreach and serve as the primary point of contact for stakeholder and bidder communications, including initial engagement, curing questions, and shortlist notifications	Review responses to stakeholder questions and develop curing questions for the IM to issue
RFP Platform Administration	Host the public RFP website containing solicitation materials and maintain the secure ShareFile site used for proposal submissions	Review materials posted on the RFP website and have access to the ShareFile documents for evaluation purposes
Threshold & Eligibility Review	Support the review of each proposal for conformance with the minimum eligibility requirements established in the RFP	Independently review each proposal for conformance with the minimum eligibility requirements established in the RFP
Scoring Support	Support the scoring process and provide guidance to promote consistency, fairness, and transparency across evaluations	Manage and evaluate the proposals, populate scoring
Pricing Evaluation	Lead the development of the value-to-cost pricing tool and the associated pricing evaluation	Provide inputs, collaborate on design, and review evaluation
Shortlist & Final Selection Review	Review and confirm preliminary shortlist selections and monitor and support final selection decisions	Develop the shortlist
Regulatory Documentation	Prepare a detailed Independent Monitor report documenting the RFP process	Review the report

Q129. Can you explain how the Company interacted with the IM throughout the RFP process?

A129. The Company and IM interacted through various communication channels including emails, calls, meetings, and document collaboration using Microsoft SharePoint. To ensure the Company remained transparent and conducted a fair process, the IM was granted access to the Company's internal SharePoint site used for the RFP. This allowed the IM to have access to all RFP materials for their review and collaboration.

Q130. Did the IM find that DTE Electric conducted a fair and competitive process that met the MPSC's Competitive Procurement Guidelines as defined in Case No. U-20852?

A130. Yes. The IM assessed the RFP process for compliance with the Competitive Procurement Guidelines in Case No. U-20852 and other applicable requirements and found that the RFP was conducted in accordance with the Guidelines. See Exhibit A-4.3 – 2025 All-Source RFP IM Report for a description by the IM on how the Company abided by and applied the Guidelines to the RFP.

RFP Protections

Q131. Did the Company's utility development arm bid into the RFP?

A131. Yes. The Company's utility development arm (i.e., DTE Electric's self-build project team) participated in the RFP.

Q132. What guidelines exist for when the utility participates in its own RFP?

A132. The Competitive Procurement Guidelines adopted in Case No. U-20852 establish guidelines to ensure a fair and unbiased solicitation process when the utility development arm participates in a Company-issued RFP. Specifically, Section 2b

in Case No. U-20852 states that "there will be no information sharing between the utility development arm and the procurement arm when utility-owned projects are allowed to bid into a solicitation." These Guidelines require a firewall between the Company's utility development and procurement arms.

Q133. Did the Company establish a firewall and comply with the Guidelines?

A133. Yes. The Company established a firewall between the Company's self-build project teams bidding into the RFP and those involved with the development, design, and evaluation of the RFP. The Company's firewall remained active through the RFP development and evaluation process. See Exhibit A-4.3 – IM Report for more information on the Company's compliance with the firewall guidelines.

Q134. Can you explain the firewall protections that were established for the RFP?

A134. As part of the RFP firewall protections, the Company divided the individuals involved with the RFP into three teams: the RFP Evaluation team, Self-build team, and RFP Specialists or shared resources. The RFP Evaluation team consisted of all members involved solely in the development of the RFP and/or evaluation of the bids. The Self-build team included all individuals supporting the bid development of any self-build projects that either bid or planned to bid into the RFP. A third team of shared resources, or RFP Specialists, was established as a central group of subject matter experts whose expertise could be leveraged by each side of the firewall, as needed. These individuals were not allowed to share information between the two teams.

Q135. How were team members informed of their firewall obligations?

A135. Team members were informed of their firewall obligations through an initial kickoff meeting describing the separation of teams followed by an emailed request to sign an acknowledgment form that described the requirements and expectations of the firewall. Every team member was required to review, sign, and return the form to the IM before receiving information related to the specific team. Once added to the firewall roster, an email was issued notifying all team members. If team members were added throughout the process, they were briefed on the requirements and expectations before being issued the acknowledgment form. The Company, with oversight from the IM, maintained this firewall to ensure no RFP-related information was shared between the RFP Evaluation and Self-build teams that could unfairly advantage the Self-build team.

Q136. Can you describe your role in the 2025 All-Source RFP?

A136. Yes. As Manager of the Long-Term Generation Strategy team, I was responsible for overseeing the development, issuance, and evaluation of the 2025 All-Source RFP and served as a member of the RFP Evaluation team.

Q137. Did any Company affiliates bid into the RFP?

A137. Yes. The Company's affiliate, DTE Sustainable Generation (DTESG), submitted a bid into the RFP.

Q138. What guidelines exist for Company affiliates bidding into a Company-issued RFP?

A138. Per Section 2a of Case No. U-20852, "if utility affiliates are responding to an RFP through submission of a bid, the utility and utility affiliate must use separate staffing. This includes a prohibition on information sharing between utility affiliates responding to the RFP and utility personnel involved in any aspect of the RFP process (such as design and preparation of the RFP, scoring/evaluation of results, or contract negotiation)."

Q139. How was separation maintained between the RFP evaluation team and any affiliate bidders?

A139. In compliance with Case No. U-20852 Section 2a, the Company maintained separation between the RFP Evaluation team and Affiliate Bid team by sharing no personnel between the two teams and housing all RFP information on a secure Microsoft SharePoint site. The IM was used for all communications between the RFP Evaluation and Affiliate Bid teams, ensuring that there was no RFP-related information sharing between the teams.

Q140. What role did the IM play in establishing or overseeing the firewall and affiliate protections?

A140. The IM oversaw all aspects of the firewall and affiliate protections including the development of the 2025 All-Source RFP Acknowledgment Form, the initial briefing meeting to all team members defining the roles and responsibilities of each team, managing communications with the affiliate, and monitoring the firewall roster and information sharing. The IM concluded that DTE Electric met all firewall protection requirements and specifically found "there is no evidence that the evaluation and selection process caused any unfair advantage or

disadvantage to any interested party or respondent." See Exhibit A-4.3 – IM Report for more information on the Company's compliance with the guidelines.

RFP Development and Stakeholder Engagement

Q141. Can you describe the RFP development and stakeholder process?

A141. The RFP development process was designed to incorporate stakeholder engagement and feedback and to provide transparency into the Company's RFP development process. The Company worked with the IM to develop the RFP materials and engage stakeholders to provide feedback on the process. The Company and IM developed the RFP over nearly eight months, with four months focused on the stakeholder engagement process. During this time, stakeholders were given several opportunities to provide feedback on the draft RFP materials. In total, the Company, along with the IM, engaged with stakeholders through two public meetings and provided three opportunities for written feedback. Table 7 below provides an overview of the stakeholder engagement.

Table 7 Stakeholder Engagement Overview

Engagement	Purpose	Materials
MPSC Staff Meeting 12/3/2024	To inform MPSC Staff members of the RFP and seek initial feedback	N/A
RFP Announcement 12/20/2024	To inform stakeholders of the upcoming RFP and the initial stakeholder meeting on January 9, 2025	N/A
RFP Development Meeting 1/9/2025	The IM, along with the Company, provided a high-level overview of the RFP and held a live question and answer segment at the end of the presentation. During this meeting, the IM provided an overview of their role, the scope of the	Exhibit A-4.5 – RFP Development Meeting Materials

Engagement	Purpose	Materials
	RFP, evaluation criteria, development process and timeline, and process for stakeholder feedback. The presentation materials were distributed to all attendees via email on January 10, 2025	
RFP Development Meeting Feedback 2/7/2025	Following this meeting, the IM sought stakeholder feedback on the materials presented. The IM compiled the feedback and drafted initial answers for the Company's review	Exhibit A-4.6 – RFP Development Meeting Feedback
Draft RFP Materials Released 2/12/2025	The Company and IM incorporated feedback received, as applicable, into the draft materials before issuing the draft RFP materials via the RFP website for stakeholder review	Exhibit A-4.7 – RFP Draft Materials
Pre-RFP Meeting 2/26/2025	During the Pre-RFP meeting, the IM discussed the IM's role, scope of the RFP, RFP materials, evaluation criteria, the RFP development process and timeline, and the stakeholder process. Again, the IM held time at the end of the session for stakeholders to provide verbal feedback or submit written feedback via email or through the website following the meeting	Exhibit A-4.8 – Pre-RFP Meeting Materials Exhibit A-4.9 – Pre-RFP Meeting Feedback
Pre-RFP Meeting Feedback 3/7/2025	Following this meeting, the IM sought feedback on the materials presented	Exhibit A-4.10 RFP Draft Materials Feedback

Throughout the stakeholder engagement process, the IM redacted all stakeholder-identifying information on materials received in response to the stakeholder process. This allowed DTE Electric and IM to draft answers without bias toward the stakeholder. In addition, the IM invited and sent reminders to individuals who registered for the meetings or signed up to receive information related to the RFP. Throughout this process, the IM was the main point of contact for all stakeholder interaction. The email address used was an IM-issued email address that the Company did not have direct access to. Following the issuance of the final RFP

materials, the Company and IM continued to engage with bidders through the formal question-and-answer process and periodic updates regarding the RFP.

Q142. Can you describe the type of stakeholders who participated in the development of the RFP?

A142. Yes. The Company worked with the IM to develop a list of stakeholders to engage as part of the stakeholder engagement process. This list included known developers in the Midwest and other regions, intervenors in the 2022 IRP (Case No. U-21193), MPSC Staff members, and other stakeholders who have participated in similar processes that the IM was aware of. The types of stakeholders who participated in the development of the RFP primarily included developers, technology providers and Original Equipment Manufacturers (OEMs), EPC firms, customer and advocacy stakeholders, and MPSC Staff members.

Q143. What information was shared with stakeholders?

A143. The Company shared all draft RFP materials, final RFP materials, reminder communications, stakeholder presentations, and non-sensitive questions and answers submitted throughout the RFP process.

Q144. How were the draft RFP materials shared with stakeholders?

A144. The draft RFP materials were shared with the stakeholders through a public RFP website.[21] The website contained all draft materials including the solicitation, instructions, and exhibits which were made available prior to the Pre-RFP

[21] https://dtee-irp-2025allsourcerfp.com/

Stakeholder meeting. Individuals who previously registered to receive updates regarding the RFP were notified via email when the materials were available.

Q145. Please describe how the RFP website was used.

A145. The RFP website served as the platform for administering the competitive procurement process, providing bidders with access to all necessary RFP documents, instructions, schedules, and updates. It also hosted non-confidential bidder questions and answers to ensure all participants had equal access to information and clarifications throughout the solicitation process. Interested participants were required to register on the website to receive updates and reminders as well as to receive access to the Company's pro forma agreements once a non-disclosure agreement (NDA) was executed. The website was hosted and monitored by the IM for the duration of the RFP process. The public website hosted by the IM helped ensure consistency, transparency, and equal access to information for all stakeholders participating in the RFP.

Q146. Why did the Company require NDAs to be executed to access the pro forma agreements?

A146. The Company required an NDA to be executed prior to receiving access to the pro formas associated with the RFP due to the sensitive nature of the contractual documents as well as to protect confidential and commercially sensitive information shared during the RFP process. Additionally, the NDAs created a pathway for bidders to subsequently provide sensitive or confidential information in their proposals.

Line No.

RFP Issuance Process

Q147. When were the final RFP materials issued?

A147. The final RFP materials were posted on the RFP website on March 31, 2025. Registered stakeholders were notified via email on April 1, 2025, of the release of the final materials and were provided links to access the materials located on the website. See Exhibit A-4.11 – RFP Final Materials for the final RFP materials.

Q148. Can you describe the major milestones between issuing the RFP and receiving submissions?

A148. Yes. Between issuing the RFP materials on March 31, 2025, and the proposal due date on November 3, 2025, several key milestones occurred including requesting a non-binding Notice of Intent (NOI) to be submitted on June 27, 2025, issuing an addendum on August 27, 2025, and closing the bidder question and answer process on October 17, 2025.

The Company requested a non-binding NOI to be submitted to understand the types of bids likely to be submitted in response to the RFP and to prepare the evaluation team for the anticipated quantity and technology types. Bidders were expected to submit the NOI via email to the IM email address at DTEAllSourceRFP@crai.com by June 27, 2025. The IM issued a reminder email to all stakeholders prior to the deadline to ensure participation. Although the Company requested NOIs to be submitted at the end of June, the Company accepted NOIs submitted after the due date to allow for a greater number of bidders to participate in the solicitation.

In August 2025, the Company issued an addendum to the RFP solicitation that moved the proposal due date from December 1, 2025, to November 3, 2025. This schedule adjustment was intended to provide respondents with earlier project certainty and enhanced clarity for planning purposes. As part of the adjustment, the shortlist target date was also accelerated by one month from April 2026 to March 2026.

The last milestone before proposal submission included the close of the bidder question and answer segment of the RFP. Bidders were given the opportunity to submit questions via the RFP website or email to the IM email address. Responses were either posted on the RFP website or shared directly with the bidder after the IM worked with the Company to provide a response. On October 17, 2025, the IM closed the question segment of the RFP to ensure the Company could provide responses before proposals were due on November 3, 2025. Stakeholders were issued a reminder on October 16, 2025, via email of the deadline.

On October 28, 2025, stakeholders were issued a final reminder that proposals were due by 5:00 p.m. on November 3, 2025.

Q149. Why did the Company give bidders seven months to prepare proposal submissions for this RFP?

A149. The Company wanted to give bidders enough time to develop a response that fully satisfied all of the requirements of the RFP and would support an IRP and potential CON. The timeline was driven by the need for bidders to complete key

development steps such as site control, interconnection applications, permitting, engineering, and equipment procurement.

Q150. What platform was used to submit proposals?

A150. The RFP used a secure file-sharing site managed by the IM called ShareFile. Each bidder that submitted an NOI was given folder access to upload all proposal materials. Bidders were given access to the ShareFile system in advance of the proposal submission.

Description of the 2025 All-Source RFP and Process

Q151. Can you explain how the Company ensured the RFP remained technology-neutral?

A151. To ensure the RFP remained technology-neutral, the Company and the IM designed the RFP to seek all types of clean technologies, including commercialized and emerging technologies that met or could meet the definition of clean energy systems per MCL 460.1003(i), renewable energy resources, or were considered energy storage technologies. The RFP was designed to accept a diverse set of resources including thermal, storage with a minimum duration of 4 hours, renewables, hybrid (solar or wind plus storage), distributed energy resources, and other emerging technologies.

To further support technology neutrality in the evaluation process, the Company established standardized evaluation criteria that were applied consistently across all proposals. These criteria included both pricing and non-pricing factors such as

project quality, development risk, and environmental, social, and economic considerations, which were applied uniformly to all technologies.

Q152. Do renewable energy resources contribute to DTE Electric's clean energy portfolio?

A152. Yes. Per MCL 460.1003(g), a utility's clean energy portfolio means the percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy. Per MCL 460.1011(g), renewable energy resources means a resource that naturally replenishes over a human, not a geological, time frame and that is ultimately derived from solar power, water power, or wind power. MCL 460.1011(g) also defines renewable energy resources to include biomass, solar, wind, kinetic energy of moving water, geothermal energy, thermal energy produced from a geothermal heat pump, landfill gas, and methane digesters.

Q153. What are energy storage systems?

A153. Per MCL 460.1005(i), energy storage systems are defined as "any technology that is capable of absorbing energy, storing the energy for a period of time, and redelivering the energy. Energy storage system does not include either of the following:

i. Fossil fuel storage.

ii. Power-to-gas storage that directly uses fossil fuel inputs."

Q154. Can you describe the 2025 All-Source RFP evaluation process?

A154. Yes. The evaluation process consisted of three primary steps designed to assess proposal eligibility, commercial viability, and economic value.

- First, the RFP Evaluation team, in coordination with the IM, reviewed all proposals for completeness and compliance with the minimum eligibility requirements. Proposals that met the minimum eligibility requirements advanced, while those with deficiencies were issued curing questions to clarify their bids or provide additional information. A total of 65 curing questions were issued to bidders to confirm minimum eligibility.
- Second, the eligible proposals underwent a combined qualitative and quantitative evaluation to develop an overall composite score, with a 50/50 weighting split between non-pricing and pricing factors. The qualitative assessment evaluated non-pricing risks and benefits through a due diligence review, while the quantitative assessment evaluated the proposed cost components of each bid relative to its energy, capacity, and other revenues. During this stage, the RFP Evaluation team and IM issued additional curing questions, as needed, to ensure consistency and understanding of each submission before finalizing scoring using the criteria established in the RFP scorecard. A total of 423 curing questions were issued to bidders in order to support evaluations.
- Finally, the evaluation team compiled the results to generate a composite score for each proposal submission, enabling a consistent comparison across all submissions.

Q155. What were the minimum eligibility requirements for this RFP?

A155. The minimum eligibility requirements for this RFP included:

- The transaction shall be structured as either a BTA, PPA, TA, or PSA;

- The project must have a commercial operation date no earlier than January 1, 2030, but no later than December 31, 2032;
- The resource must be physically located within Michigan in MISO's Local Regional Zone (LRZ) 7 and interconnected to the transmission or DTE Electric sub-transmission/distribution systems;
- The Proposal must have submitted a generator interconnection queue application or distribution pre-application prior to proposal submittal;
- The resource site(s) must be secured;
- The resource must meet the definition of a clean energy system, comply with the definition by 2035, or be considered as an energy storage system;
- If the resource is commercialized, the Respondent must have developed a project of the same technology type and of equivalent or comparable size within the U.S. or Canada;
- If the resource is an emerging technology, the Respondent must have demonstrated engineering experience with the proposed resource type; and
- The Respondent or Respondents credit support provider must have a Credit Rating for its long-term senior unsecured debt of at least "BBB-" by S&P or "Baa3" by Moody's or as deemed acceptable by DTE.

These criteria were selected to ensure the selected projects could support the retirement of the Monroe Power Plant and meet the statutory and regulatory requirements applicable to resources.

Q156. How did the design of the 2025 All-Source RFP address MISO interconnection queue delays?

A156. The Company designed the 2025 All-Source RFP to address the MISO interconnection queue delays by seeking resources with CODs between 2030 and 2032 and requiring bidders to have submitted an interconnection queue application by the RFP due date. By seeking resources nearly five years in advance of the requested CODs, the Company sought to provide enough time for bidders to submit an interconnection queue application, for projects to progress through the process, and obtain a Generation Interconnection Agreement (GIA) before the needed COD.

Additionally, the Company provided bidders with nearly ten months' notice of RFP interconnection requirements during the first stakeholder meeting in January 2025. The interconnection requirements were reiterated when the final RFP materials were issued in March 2025, giving bidders seven months to apply before the RFP due date.

Q157. Why did the Company restrict the RFP to only MISO LRZ 7?

A157. Per the MISO LRZ 7 local clearing requirement (LCR), the majority of resources need to be located within the zone. Given the amount of capacity retiring at the Monroe Power Plant, it was critical that replacement resources be located in the zone to help meet reliability requirements. By restricting the RFP to only LRZ 7, the Company ensured that the selected resources will be able to support the Company's share of the LCR and support reliability for its customers. The MISO capacity requirements, including the need for resources to be located in LRZ 7, are described in more detail by Witness Burgdorf.

Q158. How were projects deemed eligible?

A158. Projects were deemed eligible based on their ability to satisfy the minimum eligibility requirements established in the RFP. Each proposal was initially reviewed to assess whether it demonstrated compliance with these requirements based on the information provided in the proposal submission. If a proposal did not clearly demonstrate compliance with one or more requirements, the RFP Evaluation team along with the IM issued curing questions to the bidder to seek clarification or additional information. Projects that demonstrated compliance with the minimum eligibility requirements either in their proposal response or through curing were deemed eligible.

Q159. What actions did the RFP Evaluation team and IM take with projects that were not considered eligible?

A159. Projects that were not considered eligible did not continue in the evaluation process and were issued a loss notification at the time of shortlisting.

Q160. What scoring framework was used to evaluate proposals?

A160. The RFP used a two-pronged scoring framework that considered both qualitative and quantitative factors. All proposals were evaluated based on pricing and non-pricing evaluation criteria that were weighted at a 50/50 split. The non-pricing evaluation criteria consisted of project quality, development status and risks, asset-specific benefits and risks, and environmental, social, and economic benefits and risks. The pricing evaluation criteria evaluated the value-to-cost ratio, that is, the ratio of total resource benefits (i.e., energy, capacity, ancillary) to the total resource costs (i.e., capital, O&M, fuel, financing).

Q161. Can you further describe the non-pricing criteria?

A161. Yes. The non-pricing criteria consisted of the following four primary categories supported by detailed subcategories and were weighted for scoring:

1. Proposal and project quality (10%): assessed the bidder's experience developing projects of similar size and technology, demonstrating safety performance and track record, financial wherewithal and credit quality, and exceptions taken to the pro forma agreements
2. Development status and risks (15%): evaluated the proposed project schedule, procurement and risk management plans, interconnection status, permitting and regulatory approval progress, and the reasonableness of cost estimates
3. Asset-specific benefits and risks (15%): considered the project's asset life-related market risks, the technology readiness level of the proposed project, the resource optionality of the project, and the flexibility benefits associated with the project
4. Environmental, social, and economic impacts/benefits (10%): consisted of evaluating the environmental and wildlife impacts and permitting, and the Michigan economic stimulus benefits, community support, supplier and contractor diversity, and environmental justice

Q162. Can you further describe the value-to-cost evaluation?

A162. Yes. The value-to-cost evaluation compared each proposal's expected benefits against its projected costs. The value elements consisted of the revenues from the energy, capacity, and ancillary services provided by the proposed resource. The

cost elements included return on and of capital, ITCs, non-fuel O&M, variable O&M, fuel costs, startup costs, PTCs, and other costs identified by the bidder. The energy production and revenues were forecasted based on operational parameters included in proposal submissions, forecasted energy prices, and projected dispatch of each project in the energy market. The value was determined based on forecasted revenue from energy and accredited capacity value (MISO DLOL) plus ancillary services considerations. The costs were forecasted based on applicable contract costs, costs to operate, and applicable tax credits. This process was conducted by the IM.

Q163. How were the evaluation criteria applied consistently across all proposals?

A163. The evaluation criteria were applied consistently across all proposals by using the same scorecard criteria for all project types. To remain consistent in scoring, the IM remained involved when assigning scores to ensure the justification and support for selected scores were accurate and unbiased.

Q164. Can you describe the shortlisting process?

A164. Yes. Following the non-pricing and pricing evaluations, a total composite score was determined for each proposal submission. The proposals were then ranked by total composite score. Those not reaching a total composite score of 2.5 (out of 5) or above were not shortlisted. The Company subsequently further accelerated its evaluations. As a result, in February 2026, the IM issued shortlist notifications to bidders that were shortlisted and loss notifications to bidders that did not meet the RFP requirements or were not shortlisted.

Q165. Can you describe the final selections process?

A165. Yes. After shortlist notifications were issued, the IRP modeling team incorporated the projects into the IRP modeling process. Based on initial findings, the Company, in coordination with the IM, issued best and final offers to get updated pricing from all shortlisted bidders. The IRP modeling team then validated the updated pricing with modeling assumptions. The evaluation team used the PCA to identify the timing of capacity additions and the quantity of each resource type needed. The evaluation team reviewed the list of shortlisted projects to identify the resources that best met the need identified in the PCA. The projects that best met the need for MWs and timing were selected as the final projects. These results were then validated through capacity expansion, resource adequacy, and grid modeling. See Witness Manning's testimony for a full explanation on how the resources were selected through modeling.

Q166. Did the Company request Best and Final Offers (BAFOs)? If so, why?

A166. Yes. The Company issued BAFO requests on June 11, 2026, to all shortlisted projects to confirm pricing and obtain updated information regarding project development progress made since proposals were submitted in November 2025.

Q167. What was the IM's role in the final project selections?

A167. The IM provided oversight and guidance on the final project selections by reviewing the resource need identified and validating final project selections. The RFP Evaluation team shared the PCA with the IM and discussed which projects would best fit the identified need. Following alignment between the RFP Evaluation team and IM, the IM issued final award notices.

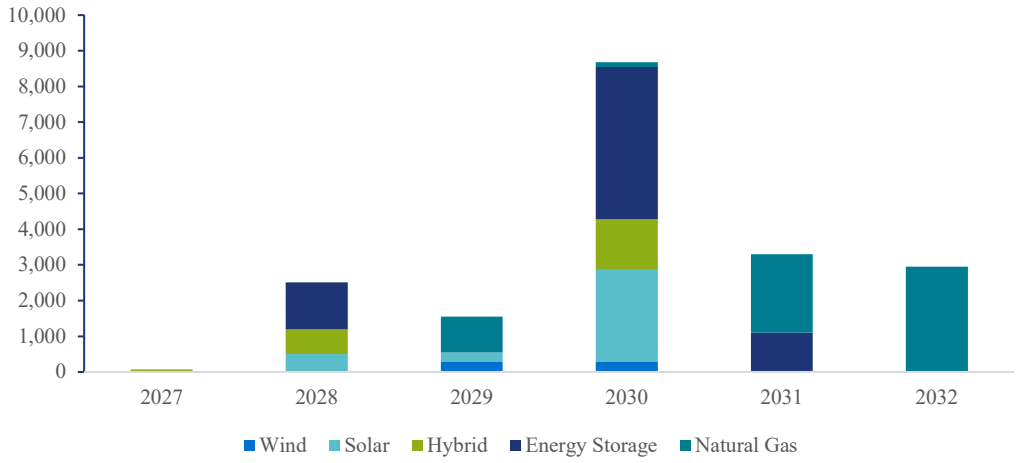
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Submissions, Evaluations, and Selections

Q168. Can you summarize the NOI submissions?

A168. Yes. The Company received non-binding NOI submissions from a diverse pool of developers and energy companies indicating strong market interest. Potential bidders included both regional and national renewable energy, energy storage, and natural gas developers. In total, the Company received NOI submissions from 29 entities indicating that 83 projects would be submitted in response to the 2025 All-Source RFP. These submissions represented over 19,000 MW of nameplate capacity, primarily driven by energy storage systems and natural gas projects. Figure 2 shows the NOI submissions the Company received prior to proposal submissions.

Figure 2 **- Total Nameplate Capacity (MW) by Resource Type & Projected COD from NOI Submissions**



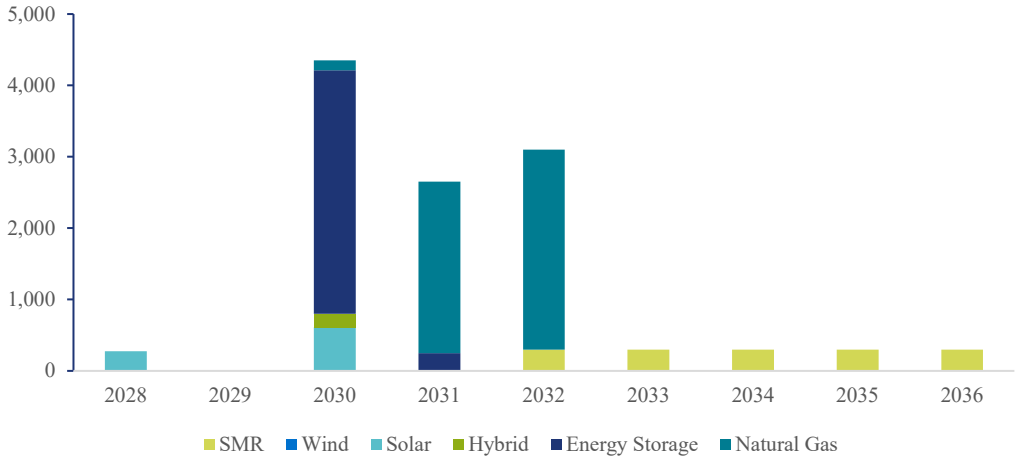
Several of the projects indicated a COD that was outside of the RFP threshold criterion of no earlier than January 1, 2030, but no later than December 31, 2032. The NOI submissions also indicated projects with multiple contract structures (i.e.,

BTA and TA). The Company did not disqualify any projects based on the NOI submissions.

Q169. Can you summarize the bid submissions?

A169. Yes. On November 3, 2025, the Company received proposal submissions from 21 entities totaling 38 projects with over 11,500 MW of nameplate capacity. Similar to the NOI submissions, several projects indicated multiple options for contract structures including BTAs and TAs, varying term lengths for PPAs or TAs, and continued to offer projects outside of the identified COD threshold criteria. Figure 3 provides an overview of the total nameplate capacity by resource type and projected COD year received in the proposals.

Figure 3 **- Total Nameplate Capacity (MW) by Resource Type & Projected COD from Proposal Submissions**



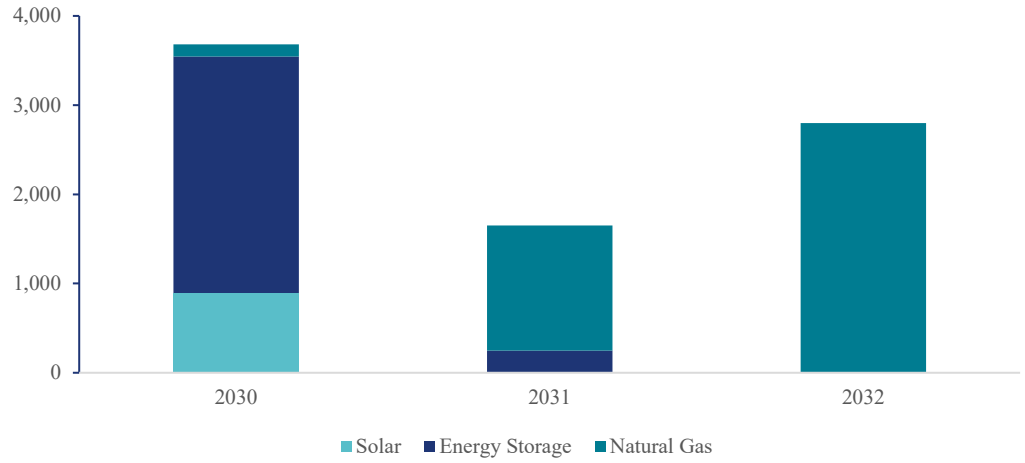
Although several projects expressed interest in the RFP by submitting NOIs, not all potential bidders submitted a proposal. In addition, there were several projects that did not submit an NOI but submitted a proposal on November 3, 2025. Although the Company required bidders to submit an NOI in June, the Company

did not disqualify bidders if they did not submit an NOI. The Company evaluated all proposals that met the minimum eligibility criteria of the RFP.

Q170. Can you describe the results of the minimum eligibility criteria review?

A170. Yes. Of the 38 projects that were submitted, 30 projects representing 8,133 MW of nameplate capacity met the RFP minimum eligibility requirements as defined above. These projects consisted of solar, energy storage systems, and natural gas projects. Figure 4 shows the total nameplate capacity of the projects that met the minimum eligibility criteria by resource type and projected COD.

***Figure 4*- Total Nameplate Capacity (MW) by Resource Type & Projected COD from Qualifying Submissions**



Eight projects did not meet the minimum eligibility requirements and were deemed ineligible for the RFP. The projects were deemed ineligible due to one of several reasons including the bidder failing to submit an interconnection queue application prior to proposal submission, the project COD was outside of the required COD range, the bidder did not demonstrate site control, or the contract structure being

sought was not offered in this RFP. Although these projects were not deemed eligible for this RFP, the Company encouraged participation in future Company opportunities.

Q171. How did the Company handle projects that did not meet the minimum eligibility requirements?

A171. Before deeming projects ineligible, the Company and the IM worked together to cure project deficiencies. All projects were given a fair opportunity to cure their bids through curing questions issued by the IM.

Q172. Can you describe the results of the pricing and non-pricing evaluation process?

A172. Yes. Over a three-month period, the Company and IM evaluated the proposal submissions using the pricing and non-pricing criteria defined in the RFP scorecard. Scores were assigned to each scorecard item after reviewing the proposal submission materials and seeking clarification through the curing process.

The evaluation resulted in total composite scores ranging from 1.69 to 4.49. A summary of the RFP evaluation results can be found in Exhibit A-4.12 – 2025 All-Source RFP Results. To protect confidential bidder information, the names of bidders and projects have been anonymized in Exhibit A-4.12.

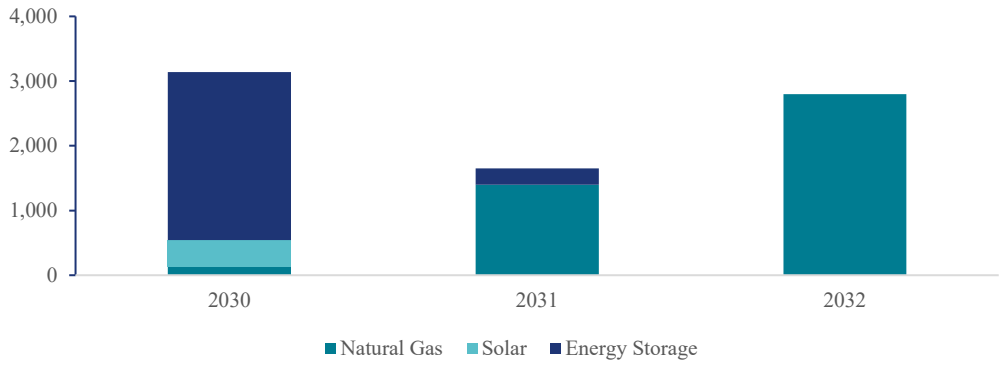
Q173. Did the Company conduct a third-party assessment of the natural gas projects to validate project feasibility and risks?

A173. Yes. The Company conducted a third-party assessment of the natural gas projects to validate project feasibility and identify project risks for further consideration in the evaluation process. The third-party assessment was used to independently validate the Company's internal evaluation while also identifying information gaps and areas requiring further consideration as needed. The Company did not use the results of this evaluation in scoring, but rather as a standalone assessment to validate the Company's internal assessment of the projects. See Exhibit A-4.13 2025 All-Source RFP Third-Party Assessment.

Q174. Can you describe the results of the shortlisting process?

A174. Yes. Using the shortlisting criteria as described above, the Company, in coordination with the IM, shortlisted 22 projects from the 30 qualifying bids. The 22 projects consisted of three solar projects, 15 energy storage projects, and four natural gas projects. Figure 5 below provides an overview of the total nameplate capacity by resource type and projected COD year for the shortlisted projects.

Figure 5 **- Total Nameplate Capacity (MW) by Resource Type & Projected COD from Shortlisted Submissions**



Seven projects, accounting for 495 MW of nameplate capacity, did not meet the composite score threshold of 2.5 or higher and were not shortlisted. The Company had one bid withdraw during the evaluation period.

Q175. Can you describe the results of the BAFO request?

A175. Yes. The Company requested best and final offers from all shortlisted projects. BAFOs or withdrawals were submitted for each of the 22 shortlisted proposals. Of the submitted BAFOs, nine projects increased pricing, ten projects had no changes to pricing, two additional projects withdrew from the process, and one project decreased pricing. This information was shared with the IRP modeling team to be incorporated in final modeling to determine the PCA.

Q176. Can you describe the results of the final project selections?

A176. Yes. The Company's final PCA identified the need for an incremental 2.1 GW of solar, 2.2 GW of natural gas, and no storage between 2030 and 2032. See Witness Manning's testimony for more information on the final PCA. A total of five projects were selected including two solar projects and three gas projects. The projects selected include:

- [redacted] project – Solar – [redacted] – 125 MW
- [redacted] project – Solar – [redacted] – 130 MW[22]
- Michigan Power Cogeneration facility– Gas – DTE Sustainable Generation – 138 MW
- Livingston County project – Natural Gas – DTE Electric – 1,400 MW[23]

[22] Though initially selected, the developer subsequently withdrew this project from consideration; see below
[23] Approximate nominal capacity

- Monroe County project – Natural Gas – DTE Electric – 700 MW[24]

Q177. What are the next steps for contracting and implementation?

A177. As described in Part VI of my testimony, the Company has executed an exclusivity agreement and is currently negotiating a Power Purchase Agreement with the third-party developer for the 125 MW solar project. The Company has also executed the Purchase and Sale Agreement with DTESG, which is included in Exhibit A-4.17. As described in Part VII of my testimony, the Company is continuing to develop the Livingston County project and the Monroe County project and is seeking cost pre-approval of those projects in this proceeding.

One of the five selected projects – the 130 MW solar project – withdrew from the 2025 All-Source RFP while negotiating the exclusivity agreement. As a result, the Company is no longer able to contract that project and is not seeking approval of that project in this proceeding.

MPSC Staff Audit

Q178. Was the RFP subject to an MPSC Staff audit?

A178. Yes. The RFP was subject to audit by MPSC Staff per the Competitive Procurement Guidelines in Case No. U-20852. The Company, along with the IM, hosted the MPSC Staff audit on March 25, 2026.

Q179. Can you describe how the MPSC Staff audit was conducted?

[24] Ibid.

A179. Yes. As described in Case No. U-20852, "Staff shall have full access to all redacted information from the utility IA or IM. In addition, the utility shall make utility staff, the IA or IM, and all unredacted proposal and scoresheets available to Staff in order for Staff to conduct a review and audit of the process prior to the Commission's decision on the application filed for approval of contracts."

Consistent with these requirements, following the evaluation of the proposal submissions, the Company, in coordination with the IM, hosted an audit with MPSC Staff for the 2025 All-Source RFP.

During the audit, the Company provided an overview of the RFP process including the solicitation, bid submissions, and evaluation results. Following this overview, MPSC Staff was granted access to a secure SharePoint site containing all relevant RFP materials, including unredacted proposal submissions and completed scorecards. After the meeting, MPSC Staff had time to independently review these materials. The Company and the IM remained available throughout the audit to address any questions or provide clarification regarding the proposals, evaluation process, and scoring. At the conclusion of the review period, the Company, IM, and MPSC Staff reconvened to discuss the process and answer any questions from the MPSC Staff. At Staff's request, access to the secure SharePoint site was extended through the following day to allow for additional time to review the materials.

Q180. Did the MPSC Staff communicate any deficiencies or concerns with the RFP solicitation at the time of the Audit?

A180. No. The MPSC Staff successfully completed their audit of the Company's 2025 All-Source RFP without identifying any deficiencies, concerns, or recommended corrective actions.

Unsolicited Bids

Q181. Did the Company receive any unsolicited bids outside of its 2025 All-Source RFP process?

A181. Yes. Following the completion of the MPSC Staff Audit of the 2025 All-Source RFP, the Company received five unsolicited bids.

Q182. Why did the Company consider these as unsolicited bids?

A182. The Company considered these as unsolicited bids because they were not submitted through the 2025 All-Source RFP solicitation as described above, or any other of the Company's active RFP solicitations. In addition, the bids were received after the Company had completed the 2025 All-Source RFP bid evaluations, shortlisting, and completion of the RFP MPSC Staff Audit. Instead, the bidders independently approached DTE Electric to present their projects and express interest in potential opportunities.

Q183. Can you describe the unsolicited bids the Company received?

A183. Yes. The Company received five unsolicited bids, each for woody biomass plant PPAs, from four bidders that totaled approximately 147 MW of nameplate capacity. All proposed projects were for existing generating assets located within MISO LRZ 7, with original commercial operation dates ranging from the late 1980s through the mid-1990s. The projects either meet the definition of a clean

energy system or include commitments from bidders to meet the definition as a requirement of any potential PPA.

Q184. Is woody biomass considered a renewable energy resource under Michigan law?

A184. Yes. MCL 460.1011(g) defines a "renewable energy resource" and expressly includes qualifying biomass. Specifically, MCL 460.1011(g)(i) includes biomass used by qualifying renewable energy systems, including biomass used by renewable energy systems that were already in commercial operation when the applicable statutory amendments took effect. MCL 460.1003(b) also defines "biomass" to include, amongst other materials, trees, wood, and certain wood wastes and residues, subject to the requirements of the statute.

The unsolicited proposals described above are for existing woody biomass generating facilities. Accordingly, to the extent the facilities use biomass and otherwise satisfy the requirements applicable to a renewable energy system under MCL 460.1011, the electricity generated from those resources qualifies as renewable energy under the Michigan energy law.

Q185. Did the Company evaluate these unsolicited bids?

A185. Yes. The Company conducted an accelerated evaluation of the unsolicited bids using the 2025 All-Source RFP framework. After receiving the first inquiry in March 2026, DTE Electric requested submittal of any unsolicited proposals using the 2025 All-Source RFP pricing sheet and supporting materials to facilitate a robust, consistent, and fair evaluation of the unsolicited bids compared to those

that participated in the RFP. The Company evaluated the unsolicited bids through the same process and criteria as defined above in the 2025 All-Source RFP by screening them against the minimum eligibility requirements, assessing each proposal using both pricing and non-pricing criteria to develop a composite score, conducting value-to-cost pricing analysis, and issuing curing questions to secure additional details and better evaluate bids.

Q186. Why did the Company evaluate the unsolicited bids?

A186. The Company evaluated the unsolicited bids to ensure that its 2026 IRP considered all known resource opportunities available at the time of planning and to verify that the resources selected in the PCA represented the most reasonable and prudent option. Given the unique attributes of these existing biomass facilities as renewable, baseload generation resources with available capacity in the near-term, the Company determined that the consideration of these resources contributed to prudent plan development.

Q187. What were the results of the unsolicited bids evaluation?

A187. All five projects met the minimum eligibility requirements and advanced to the pricing and non-pricing evaluation phase. As a result of the pricing and non-pricing evaluations, four of the five projects achieved a total composite score threshold of 2.5 or above. As with the 2025 All-Source RFP, a composite score of 2.5 or above was the threshold for shortlisting. As a result, these four shortlisted bids were included in IRP modeling as possible resource alternatives when developing the PCA. Based on the modeling results, as discussed by Witness Manning, none of the biomass projects were selected as part of the Company's

PCA because while the baseload renewable power they provide has reliability benefits to the system, they were not an economic resource relative to other resources including other baseload power resources.

Q188. Were the unsolicited bids subject to an MPSC Staff audit?

A188. As unsolicited bids, the biomass projects were not submitted through a formal RFP conducted under the Commission's Competitive Procurement Guidelines and therefore were not subject to the standard audit and oversight processes applicable to a competitive solicitation. The Company's consideration of unsolicited renewable energy proposals is consistent with Commission precedent established in its REP proceedings in Case No. U-18232, where the Commission authorized DTE Electric to pursue renewable energy resources through both competitively solicited and non-solicited procurement pathways, including PPAs and other renewable energy opportunities.

Although the unsolicited bids were outside the 2025 All-Source RFP, the Company sought to evaluate them as consistently as practicable with the resources evaluated through that solicitation. The Company therefore used the same RFP evaluation framework and criteria, as applicable. CRA performed a value-to-cost pricing analysis for the unsolicited proposals, consistent with the analytical role it performed for bids submitted through the 2025 All-Source RFP.

Nevertheless, to promote transparency and facilitate regulatory review, the Company voluntarily offered MPSC Staff the opportunity to conduct an additional, separate audit and review of these unsolicited bids. Through that

process, MPSC Staff was provided information regarding the bids, the Company's evaluation methodology, and the basis for the Company's conclusions. Accordingly, the unsolicited bids were reviewed by MPSC Staff through a dedicated audit process conducted for those proposals on July 29, 2026.

Q189. Did the MPSC Staff communicate any deficiencies or concerns with the unsolicited bids at the time of the Audit?

A189. No. MPSC Staff completed their audit of the unsolicited bids and did not communicate any deficiencies, concerns, or recommended corrective actions.

PART VI – MCL 460.6t(11) COST PREAPPROVAL REQUESTS FOR RFP SELECTED RESOURCES

Q190. What does the IRP statute allow for with regard to seeking cost pre-approval of resources within the first three years of the IRP?

A190. MCL 460.6t(11) allows the MPSC to approve costs for resources that are commenced within three years after the approval of the IRP:

> (11) In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation or energy storage facility, the purchase of an existing electric generation or energy storage facility, the purchase of power under the terms of the power purchase or energy storage agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated

resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.

Q191. Which years are expected to comprise the three-year approval period following Commission approval of the 2026 IRP?

A191. With the 2026 IRP filed on September 24, 2026, the statutory timeline for a final Order in the case is expected between 300-360 days, or between July 2027 and September 2027. Therefore, the three-year approval period after the approval of the 2026 IRP includes 2028, 2029, and 2030.

Q192. Which RFP-selected resources subject to the Company's cost pre-approval requests do you support?

A192. I support the Company's requested MCL 460.6t(11) cost pre-approvals for two resources selected through the 2025 All-Source RFP and that are planned to commence within the three-year approval period after Commission approval of the 2026 IRP:

- [redacted] – Solar PPA – [redacted] – 125 MW
- Michigan Power Cogeneration facility – Natural Gas PSA – DTESG – 138 MW

Solar PPA

Q193. Please describe the solar project, including technology type, size, location, expected capacity, and expected commercial operation date.

A193. The solar project is a planned 125 MW solar project located in [redacted], MI, with an expected COD of January 1, 2030. The project is being developed by [redacted].

Q194. What is the ownership or contractual structure for the solar project?

A194. DTE Electric has executed an exclusivity agreement with the developer with the intent of entering into a 20-year PPA. Under the PPA, DTE Electric will receive the energy, capacity, and Renewable Energy Credits (RECs) associated with the solar project.

Q195. What is the expected cost of the PPA for the solar project?

A195. The Company requests the Commission specify and approve a price of [redacted] for the proposed 20-year PPA. The proposed price is fully-bundled and includes the energy, capacity, and RECs associated with the project. Since the Company's selection of the project, the developer's pricing has increased as contract negotiations have progressed. The final contract price may differ from the current estimate, and the Company may update its cost estimate within 150 days of filing, consistent with MCL 460.6t(7). For additional information regarding the costs associated with the solar PPA, see confidential Exhibit A-4.15.

Q196. Was the solar project selected as the result of a competitive solicitation?

A196. Yes. The solar project was selected in the 2025 All-Source RFP. The project was evaluated using the pricing and non-pricing criteria described in Part V of my testimony and was selected for inclusion in the PCA. The PPA price is competitive compared to other recent Company solicitations and contracts for solar resources.

A copy of the proposal for the Solar PPA project is provided as confidential Exhibit A-4.14.

Q197. What are the expected operating characteristics of the solar project?

A197. As a solar resource, the project will produce energy intermittently. DTE Electric estimates that solar projects will operate with an annual average capacity factor of 24%. Based on the estimated capacity factor, the estimated annual average (2030-2046) energy production from the project is 260,173 MWh.

Q198. How will the solar project contribute to the Company's clean energy portfolio?

A198. The project is a solar resource that will generate renewable energy and associated RECs. The energy and RECs purchased under the proposed PPA will support the Company's compliance with Michigan's Renewable Portfolio Standards (RPS) and contribute to the Company's clean energy portfolio.

Q199. Why is the solar project a reasonable and prudent option for DTE Electric's customers?

A199. The solar project is a reasonable and prudent option because it was selected through the 2025 All-Source RFP, provides renewable energy and RECs needed to support compliance with Michigan's RPS, and offers a competitively determined PPA price. As described by Witness Manning, the PCA includes additional solar resources to support forecasted RPS compliance based on the favorable economics of solar compared to wind. Thus, the Solar PPA project

provides a competitively procured means of obtaining a portion of the renewable energy and RECs reflected in the PCA.

Q200. How does the solar project support the use of a Michigan resident workforce?

A200. The project will bring socioeconomic benefits to the local community, including local employment for project construction. The project is located in [redacted], Michigan, and the developer has committed to using a construction workforce consisting of at least 95% Michigan residents. This commitment supports construction of the project using a Michigan resident workforce to the extent practicable, consistent with MCL 460.6t(8)(b).

Q201. What specific Commission approval is the Company requesting for the [redacted] project?

A201. Under MCL 460.6t(11), the Company requests that the Commission approve the [redacted] project as part of the PCA and specify the [redacted] price under the 20-year PPA. If the project is approved, the executed contract will be filed with the Commission in an ex parte filing following final approval in this case proceeding.

DTE Sustainable Generation – Michigan Power Cogeneration

Q202. Please describe the Michigan Power Cogeneration facility, including technology type, size, location, expected capacity, and expected commercial operation date.

A202. The Michigan Power Cogeneration facility is a 138 MW gas-fired combined-cycle cogeneration plant that has been in commercial operation since 1995. The plant is

currently owned by DTESG and is located in Ludington, Mason County, Michigan. DTE Electric proposes to acquire the existing facility effective October 24, 2030, following expiration of the facility's existing PPA.

Q203. What is a cogeneration plant?

A203. A cogeneration plant, also known as a combined heat and power (CHP) plant, produces both power and useful thermal energy from the same fuel input. Michigan Power Cogeneration produces both power and useful thermal energy. Power is produced through the operation of a combined-cycle gas plant in a 1x1 combined-cycle configuration (i.e., one gas turbine and one steam turbine). Useful thermal energy is produced in the form of steam, which is delivered and sold to a third party as an additional source of revenue.

Q204. What is the ownership or contractual structure for the Michigan Power Cogeneration facility?

A204. DTE Electric has entered into a PSA with DTESG to acquire the Michigan Power Cogeneration facility. DTE Electric will acquire, own, and operate the Michigan Power Cogeneration facility effective on October 24, 2030, after the expiration of the facility's existing PPA. Under the PSA, the purchase price will be based on the net book value of the property, plant, equipment, and related assets at the time of closing. The PSA is provided as confidential Exhibit A-4.17.

Q205. What is the anticipated purchase price for the Michigan Power Cogeneration facility for which the Company is requesting pre-approval?

A205. Under the PSA, the purchase price will equal the net book value of the property, plant, equipment, and related assets as of the closing date. The PSA anticipates a purchase price of approximately $130 million, which is equivalent to $942/kW of nameplate capacity. The final purchase price will be determined at closing in accordance with the PSA. For additional information regarding the costs associated with the PSA, see Exhibit A-4.18.

Q206. Did the Company obtain information supporting the net book value of the Michigan Power Cogeneration facility?

A206. Yes. At the Company's request, DTESG provided the letter attached as Exhibit A-4.19 identifying its current estimate of the net book value of the property, plant, equipment, and related assets as of the anticipated closing date and describing the basis for that estimate. I did not independently prepare or audit DTESG's accounting calculation. As discussed above, under the PSA the final purchase price will equal the net book value of the specified assets as of the closing date.

Q207. Was the Michigan Power Cogeneration facility selected through a competitive solicitation?

A207. Yes. As described above, the Michigan Power Cogeneration facility was evaluated and selected through the 2025 All-Source RFP and was subsequently included in the PCA through the IRP modeling and resource selection process. As an existing dispatchable, gas-fired combined-cycle resource that meets the criteria for a clean energy system under MCL 460.1003(i)(iii), Michigan Power Cogeneration will provide energy, accredited capacity, and resource adequacy value as part of the Company's overall portfolio. Additionally, the PSA price is competitive compared

to other options for dispatchable resources capable of contributing to the Company's clean energy portfolio. A copy of the DTESG proposal for the Michigan Power Cogeneration facility is provided as confidential Exhibit A-4.16.

Q208. What statutory provision governs the Michigan Power Cogeneration facility's treatment as a clean energy system?

A208. As noted in Part I, MCL 460.1003(i) defines a "clean energy system" to include "an electricity generation facility or system or set of electricity generation systems" that meets one of the requirements identified in the statute. The provision applicable to the Michigan Power Cogeneration facility is MCL 460.1003(i)(iii), which includes within the definition of clean energy system an independently owned combined-cycle power plant fueled by natural gas that had a power purchase agreement with an electric provider as of the effective date of the provision and that, by 2030, receives Commission approval for a plan that achieves functional equivalence with the Clean Energy Standard in MCL 460.1051(1)(b) through greenhouse-gas reductions using CCS and other available applications. In reviewing such a plan, the Commission considers best available technology and applications, rate affordability, resource adequacy, and grid reliability.

Q209. How does the Company's CEP provide the functional equivalence plan contemplated by MCL 460.1003(i)(iii)?

A209. The Michigan Power Cogeneration facility is an independently owned combined-cycle power plant fueled by natural gas, and it was subject to a PPA with an electric provider on the effective date of MCL 460.1003(i)(iii). That existing PPA remains in effect until the Company's proposed acquisition in 2030. The Michigan Power

Cogeneration facility therefore meets the facility-specific criteria for treatment as a clean energy system under MCL 460.1003(i)(iii). As discussed below and by Witness Hajj, the Company's overall CEP supplies the plan-level functional equivalence showing required by that provision.

Q210. How is the Michigan Power Cogeneration facility addressed in the Company's CEP under MCL 460.1003(i)(iii)?

A210. The "plan" referenced in MCL 460.1003(i)(iii) is the Company's overall CEP. This interpretation is supported by MCL 460.1003(i), which defines a clean energy system to include a "system or set of electricity generation systems," and MCL 460.1003(i)(iii), which calls for Commission approval of a "plan" that achieves functional equivalence.

DTE Electric's CEP includes the Michigan Power Cogeneration facility as part of an integrated portfolio of generation resources and other actions reflected in the PCA. That integrated portfolio meets the applicable CES requirements and results in substantial greenhouse gas reductions through the combined effects of resource retirements, resource additions, demand side resources, CCS, and other available applications reflected in the PCA. Accordingly, the functional equivalence showing is based on the overall CEP and its portfolio-wide greenhouse gas reductions, rather than a standalone emissions analysis of the Michigan Power Cogeneration facility. Michigan Power Cogeneration is therefore included as part of the set of electricity generation systems covered by the CEP rather than treated as an isolated facility required to demonstrate standalone equivalence.

Witness Hajj explains how the CEP is incorporated into the Company's IRP filing, and addresses the Company's request for approval of the overall CEP. Witness Marietta presents the projected portfolio-wide greenhouse gas reductions resulting from the PCA.

Q211. What are the expected operating characteristics of the Michigan Power Cogeneration facility?

A211. As a gas-fired cogeneration resource, the Michigan Power Cogeneration facility is dispatchable and is expected to operate as a baseload resource. The plant is capable of ramping between its minimum capacity of 100 MW and its maximum capacity of 138 MW, allowing it to dispatch based on energy market needs. Given the efficient operations allowed by the combined cycle and cogeneration operations, the plant is expected to be economic to operate during most periods and is expected to operate as a baseload resource.

Q212. What are the design configuration and major components of the Michigan Power Cogeneration facility?

A212. Michigan Power Cogeneration is a 1x1 CCGT with one gas turbine and one steam turbine. The gas turbine generator is a GE Frame 7EA with a capacity of 83.5 MW. Heat from the gas turbine is recovered in the heat recovery steam generator (HRSG), which is a Deltak natural circulation, finned-tube design. The steam turbine is also manufactured by GE and has a nameplate capacity of 58 MW. The plant also includes two auxiliary boilers, generator step up transformers, and transmission interconnection at 138 kV.

Q213. How is natural gas supplied to Michigan Power Cogeneration?

A213. As an operating plant, Michigan Power Cogeneration has existing natural gas supply. The gas supply requirement for the plant is approximately 30,500 Dth/d (1,270 Dth/hr). Natural gas is delivered to Michigan Power Cogeneration via the DTE Gas system and gas supply is provided at MichCon CityGate by a third-party gas marketer. Michigan Power Cogeneration has agreements for firm natural gas transportation and storage capacity with DTE Gas, ensuring reliable fuel supply to the plant. The gas supply for Michigan Power Cogeneration is discussed in more detail by Witness Swiech.

Q214. What are the parameters of the steam supply agreement?

A214. As described above, Michigan Power Cogeneration delivers steam to a third party as an additional source of revenue. Michigan Power Cogeneration maintains a steam supply agreement with [redacted]. [redacted] A portion of the steam produced in the HRSG from the gas turbine heat exhaust is delivered to [redacted]. The revenues from the steam supply agreement with [redacted] represent an additional value stream for the project beyond energy and capacity and are expected to offset approximately 20% of the facility's fuel costs.

Q215. What is the heat rate of the Michigan Power Cogeneration facility?

A215. Given its nameplate capacity of 138 MW and its hourly gas supply requirement of 1,270 Dth/hr, the heat rate of the Michigan Power Cogeneration facility is

approximately 9,209 Btu/kWh. However, as described above, heat from the gas turbine also produces steam that is sold to [redacted]. After accounting for steam sales, the heat rate of the Michigan Power Cogeneration facility is approximately 7,645 Btu/kWh. This heat rate is consistent with the overall efficient operations of Michigan Power Cogeneration and its historical dispatch as a baseload plant.

Q216. What are the expected O&M costs for the Michigan Power Cogeneration facility?

A216. The expected fixed O&M costs for Michigan Power Cogeneration are $11.3 million per year. These costs include labor, routine maintenance, outage maintenance, insurance, easements, and other operating expenses. Property taxes are separately reflected in Exhibit A-4.18 as part of the facility's projected annual costs. Exhibit A-4.18 provides the annual fixed O&M, variable O&M, fuel, depreciation, return, property tax, generation, and cost assumptions supporting the Company's request.

Q217. What is the expected useful life of the Michigan Power Cogeneration facility?

A217. For the purposes of the 2026 IRP modeling, Michigan Power Cogeneration is expected to operate throughout the forecast period. At the time of acquisition, Michigan Power Cogeneration will have been operating for 35 years. Given that Michigan Power Cogeneration has been operated as a baseload resource and has been maintained according to manufacturer recommendations, it has continued to operate reliably and is expected to continue reliable operations for the foreseeable future. B&V provided an Independent Engineer's Report, included in confidential

Exhibit A-4.16, which finds that the remaining useful life of Michigan Power Cogeneration is through at least 2045 if it is operated and maintained in accordance with good industry practice. DTE Electric intends to operate and maintain Michigan Power Cogeneration consistent with its prior operations and to continue reliable operations through the IRP study period.

Q218. How will Michigan Power Cogeneration be decommissioned at the end of its useful life?

A218. There are no legal, contractual, or other obligations requiring the removal or dismantlement of the facility. As a result, no studies have been conducted at this time to assess the potential decommissioning of Michigan Power Cogeneration. Any potential decommissioning of Michigan Power Cogeneration will be studied and accounted for in future depreciation cases before the MPSC, consistent with current practice.

Q219. Is the Michigan Power Cogeneration facility within three miles of an Environmental Justice community?

A219. No. Michigan Power Cogeneration is not located within three miles of an EJ community that has a MiEJScreen score of greater than 75.

Q220. Are there socioeconomic benefits associated with the continued operation of Michigan Power Cogeneration?

A220. Yes, there are various socioeconomic benefits associated with the continued operation of Michigan Power Cogeneration. The facility has been a good neighbor and economic contributor to the Ludington community since 1995. The plant

provides opportunities for well-paying jobs, local power generation, and further supports the local economy through its steam sales to [redacted]. Michigan Power Cogeneration employs 21 full-time employees, 11 of whom have worked at the facility for twenty or more years. Michigan Power Cogeneration operates efficiently and with best available emissions-control technologies. DTE's acquisition of Michigan Power Cogeneration ensures that the facility will continue to provide socioeconomic benefits to the Ludington community.

Q221. Is Michigan Power Cogeneration being acquired from an affiliate of the Company?

A221. Yes, DTESG is an affiliate of DTE Electric and a non-utility subsidiary of DTE Energy.

Q222. What MPSC Code of Conduct requirement applies to the proposed acquisition of Michigan Power Cogeneration from an affiliate?

A222. The MPSC has established Code of Conduct rules[25] that govern transactions between utilities and affiliates. For this proposed acquisition, R 460.10108(4) provides that "asset transfers from an affiliate or other entity within the corporate structure to a utility for which the cost is not governed by section 10ee(8) of 2016 PA 341, MCL 460.10ee(8) is at the lower of cost or fair market value." Accordingly, the purchase price for the proposed acquisition of Michigan Power Cogeneration may not exceed the lower of cost or fair market value.

[25] December 20, 2018, Order in Case No. 18361.

Q223. What steps did DTE Electric take to comply with the Code of Conduct in evaluating DTESG's proposal?

A223. DTE Electric evaluated DTESG's proposal through the 2025 All-Source RFP using the applicable RFP requirements and evaluation criteria. Because DTESG is an affiliate, the Company also implemented measures to maintain appropriate separation between DTESG and the DTE Electric personnel involved in evaluating the proposals. DTESG did not receive competitively sensitive information or an informational advantage over non-affiliated bidders. As discussed below, the PSA also provides that the purchase price will be based on net book value at closing, while the competitive RFP results also provide market-based support for the reasonableness of the transaction price.

Q224. What is the basis for determining that the Michigan Power Cogeneration project is being acquired at the lower of cost or fair market value?

A224. As noted above, the PSA provides that the purchase price will equal the net book value of the property, plant, equipment, and related assets as of the closing date. The PSA anticipates a purchase price of approximately $130 million, and the final purchase price will be determined at closing. DTESG also provided the information included in Exhibit A-4.19, which identifies its current estimate of the closing date net book value and describes the basis for that estimate.

The 2025 All-Source RFP provides separate, market-based support for a fair market value assessment. The Michigan Power Cogeneration proposal was evaluated against competing resource proposals through that process and was selected based on the RFP evaluation. Based on the PSA's net book value pricing

mechanism and the results of the competitive solicitation, the transaction price is consistent with the Code of Conduct's lower of cost or fair market value criteria.

Q225. How did the Company ensure that information was not shared with DTESG in violation of the Code of Conduct?

A225. DTE Electric and DTESG maintained the structural and functional separation designed to prevent DTESG from receiving preferential treatment or competitively sensitive information. In the course of the 2025 All-Source RFP, DTE Electric evaluated DTESG's proposal using the applicable RFP requirements and evaluation criteria, while applying additional safeguards appropriate for an affiliate bidder. DTESG was not provided competitively sensitive information or an informational advantage over non-affiliated bidders. RFP-related communication between DTE Electric and DTESG was managed through the IM, CRA, and there was no direct communication between employees of DTE Electric and employees of DTESG regarding the evaluation of DTESG's proposal in the 2025 All-Source RFP.

Q226. Why is the Michigan Power Cogeneration facility a reasonable and prudent option for DTE Electric's customers?

A226. The Michigan Power Cogeneration facility was selected through the 2025 All-Source RFP following evaluation against competing proposals. As described by Witness Manning, the Michigan Power Cogeneration facility was selected in the IRP modeling based on its economics and contribution to the Company's energy and capacity needs. As a dispatchable combined-cycle generating facility, Michigan Power Cogeneration also provides significant energy and capacity

benefits, contributing to the resource adequacy of DTE Electric's generation portfolio. The acquisition would add an existing dispatchable resource to the Company's portfolio at a purchase price determined under the PSA's net book value mechanism. Taken together, the competitive solicitation, IRP modeling results, capacity contribution, and proposed acquisition terms demonstrate that the Michigan Power Cogeneration facility is a reasonable and prudent resource for customers.

Q227. What specific Commission approvals is the Company requesting for the Michigan Power Cogeneration facility?

A227. The Company requests that the Commission approve the Michigan Power Cogeneration facility as part of the PCA and approve the PSA with DTESG for the Michigan Power Cogeneration facility (confidential Exhibit A-4.17) and specify the costs approved for the acquisition under MCL 460.6t(11). Under the PSA with DTESG, the purchase price will equal the net book value of the property, plant, equipment, and related assets as of the closing date. The PSA anticipates a purchase price of approximately $130 million. The Company therefore requests cost pre-approval based on that estimated amount, with the final purchase price to be determined at closing under the PSA's net book value mechanism.

PART VII – CERTIFICATE OF NECESSITY REQUESTS

Q228. What does MCL 460.6s allow for and what is required by the MPSC for Certificates of Necessity requests?

A228. MCL 460.6s allows an electric utility to request Certificates of Necessity (CON) for certain major resource decisions, including construction of a new electric

generation facility, a significant investment in an existing generation facility, purchase of an existing electric generation facility, or a long-term power purchase agreement for capacity when the applicable statutory cost and term thresholds are met. Specifically, Subsection (1) states:

> *An electric utility that proposes to construct an electric generation facility, make a significant investment in an existing electric generation facility, purchase an existing electric generation facility, or enter into a power purchase agreement for the purchase of electric capacity for a period of 6 years or longer may submit an application to the commission seeking a certificate of necessity for that construction, investment, or purchase if that construction, investment, or purchase costs $100,000,000.00 or more and a portion of the costs would be allocable to retail customers in this state. A significant investment in an electric generation facility includes a group of investments reasonably planned to be made over a multiple year period not to exceed 6 years for a singular purpose such as increasing the capacity of an existing electric generation plant. The commission shall not issue a certificate of necessity under this section for any environmental upgrades to existing electric generation facilities. If the application is for the construction of an electric generation facility of 225 megawatts or more or for the construction of an additional generating unit or units totaling 225 megawatts or more at an existing electric generation facility submitted as required under section 6t(13), the commission shall consolidate its proceedings under section 6t and this section. If the commission approves or denies an application for an electric generation facility under this section that has been submitted as required under*

section 6t(13), the provisions of this section prevail in a conflict with section 6t.

The Company is seeking CON approvals pursuant to MCL 460.6s(3). Accordingly, this part of my testimony addresses the statutory findings associated with the Company's identified need for power, the reasonableness and prudence of the proposed generation technology, and the specific resources for which CON approvals are requested.

As summarized by Witness Hajj in Part II of her testimony, MPSC CON filing requirements require the utility to:

- Identify the requested relief;
- Describe the proposed resource or resources;
- Demonstrate the need for the capacity and energy;
- Evaluate reasonable alternatives, provide cost and risk information, and support why the proposed resource is reasonable and prudent for the customers; and
- Hold a pre-application consultation with Commission Staff to help refine the application and support efficient regulatory review.

Q229. What types of CON determinations and approvals may the Commission make under MCL 460.6s(3)?

A229. Under MCL 460.6s(3), the Commission may grant a Certificate of Necessity based on several distinct determinations, including findings regarding:

- The need for additional power;

- The generation technology and size of the resources selected are the most reasonable and prudent means of meeting that need; and
- The price of a power purchase agreement or estimated purchase or capital costs and the financing plan for a generation resource will be recovered in rates from the electric utility's customers.

Q230. What CON approvals is the Company seeking in this filing?

A230. The Company is seeking six CON approvals associated with the proposed Livingston County and Monroe County CCGT projects. Specifically, the Company is requesting that the Commission approve the following CONs:

1. **Livingston County project – Need for Power:** A determination that the power to be supplied as a result of the proposed construction of the Livingston County project is needed;
2. **Livingston County project – Resource Selection:** A determination that the size, fuel type, and other design characteristics of the Livingston County project represent the most reasonable and prudent means of meeting that power need;
3. **Livingston County project – Cost and Financing:** A determination that the estimated capital costs of and financing plan for the Livingston County project, including the costs of siting and licensing the facility and the estimated cost of power from the facility, will be recoverable in rates from the Company's customers, subject to MCL 460.6s(4)(c);
4. **Monroe County project – Need for Power:** A determination that the power to be supplied as a result of the proposed construction of the Monroe County project is needed;

5. **Monroe County project – Resource Selection:** A determination that the size, fuel type, and other design characteristics of the Monroe County project represent the most reasonable and prudent means of meeting that power need; and
6. **Monroe County project – Cost and Financing:** A determination that the estimated capital costs of and financing plan for the Monroe County project, including the costs of siting and licensing the facility and the estimated cost of power from the facility, will be recoverable in rates from the Company's customers, subject to MCL 460.6s(4)(c).

Because both proposed facilities are Company-owned self-build projects, the Company is not seeking a determination regarding the reasonableness and prudence of a power purchase agreement under MCL 460.6s(3)(c). The remainder of this Part's (Part VII) testimony addresses each of the applicable CON determinations and explains how the proposed Livingston County project and Monroe County project satisfy those requirements.

Q231. What is the Company's identified need for power and how was it determined?

A231. As discussed by Witness Manning and reflected in the Company's PCA, the Company's need for additional power is driven by the planned retirement of existing generating resources, evolving resource adequacy requirements, and forecasted customer demand. These factors create a need for additional energy and accredited capacity when Monroe Power Plant Units 1 and 2 retire. Witness Manning provides quantitative analysis supporting the timing and magnitude of that need.

Q232. Can the identified need be met through the Company's existing resources?

A232. No. The identified need cannot be met through the Company's existing resources alone because the Company's modeling demonstrates a need for replacement capacity as existing resources retire, including Monroe Units 1 and 2. While the Company's existing resources continue to provide considerable customer and reliability value, they are not sufficient to satisfy the Company's forecasted capacity and energy requirements throughout the planning period. The proposed Livingston County facility and Monroe County facility are among the resources that help fill that need with modern, efficient, dispatchable resources that support reliable service throughout the planning period.

Q233. What alternatives did the Company evaluate in determining what resource type(s) could meet the Company's identified power need?

A233. As discussed by Witness Manning, the Company evaluated a broad range of resource alternatives through the 2026 IRP process, including renewable generation, energy storage, energy waste reduction (EWR), demand response, market purchases, other supply-side resources, and a no-build alternative. The Company also considered the results of the 2025 All-Source RFP, which provided market information regarding available resource alternatives.

The Company evaluated whether these alternatives could satisfy its identified capacity, energy, and reliability needs at the required scale and timing and at reasonable cost and risk to customers. Based on that evaluation, CCGT generation was identified as the most reasonable and prudent resource type for meeting the

Company's need for firm, dispatchable capacity and energy as one component of the broader PCA.

Witness Manning provides additional detail regarding the Company's modeling, portfolio evaluation, sensitivities, and comparative analysis of resource alternatives, and Witness Brooks provides additional detail regarding the Company's resource adequacy analysis.

Q234. Why is CCGT generation the most reasonable and prudent resource type to meet the Company's identified need for power?

A234. As discussed above, the Company's IRP evaluated numerous resource alternatives, including renewable generation, energy storage, EWR, demand response, market purchases, and dispatchable generation. Based on that evaluation, CCGT generation was identified as the most reasonable and prudent technology for meeting the Company's need for firm, dispatchable capacity and energy as part of the broader PCA. This conclusion is supported by the Company's IRP modeling and resource adequacy analyses, as discussed by Witness Manning and Witness Brooks, and by the results of the Company's 2025 All-Source RFP described earlier in my testimony. Witness Stansell provides additional details regarding the specific technology configuration and design characteristics of the proposed facilities.

Q235. Why is firm dispatchable generation needed in addition to resource alternatives, including the other resources included in the PCA?

Line No.

A235. Renewable energy, energy storage, EWR, and demand response all play important roles in the Company's PCA, but they do not fully replace the reliability and operational attributes provided by firm dispatchable generation. Firm dispatchable resources can be called upon when needed and can sustain energy production for the duration required to reliably serve customers.

Firm dispatchable generation is an important component of the Company's balanced resource portfolio because the Company must maintain reliable service during all hours of the year, including periods of peak demand, extreme weather, lower renewable output, and regional system stress. These planning considerations are consistent with reliability risks identified by NERC related to demand growth, generator retirements, and changes in the resource mix.[26] MISO's Reliability Imperative reports reliability challenges arising from load growth, generation fleet transformation, and the need to maintain sufficient dispatchable resources during the resource transition.[27] Unlike intermittent renewable resources or duration-limited storage resources, firm dispatchable resources can produce energy for extended periods and can be committed or dispatched based on system needs. As existing baseload generation resources retire and new baseload demand is being added to the system, firm dispatchable resources remain critical to maintaining a balanced and reliable resource mix.

[26] North American Electric Reliability Corporation, *2024 Long-Term Reliability Assessment* (December 2024), Executive Summary, pp. 6-10; "Resource Mix Changes," pp. 21-29; and "Demand Trends and Implications," pp. 31-33.
[27] Midcontinent Independent System Operator, Inc., *MISO's Response to the Reliability Imperative* (Feb. 21, 2024), Executive Summary, pp. 2-5, and "Challenges Driving the Reliability Imperative," pp. 6-12.

Accordingly, the PCA relies on a balanced mix of renewable energy, energy storage, demand-side resources, and firm, dispatchable generation working together to maintain reliability and affordability. The proposed Livingston County project and Monroe County project provide the firm, dispatchable capacity and energy included in that balanced portfolio.

Q236. How do CCGT resources support reliability in MISO LRZ 7?

A236. CCGT resources would support reliability in MISO LRZ 7 by adding firm, dispatchable capacity located in Michigan. Such capacity supports the Company's resource adequacy requirements and reduces reliance on capacity imports and market purchases that may be less available during periods of regional scarcity or system stress. Resources located within LRZ 7 provide both local reliability benefits and broader system value by increasing the amount of accredited capacity available within the zone while helping reduce dependence on imports during stressed system conditions. As discussed further by Witness Burgdorf, MISO's local resource requirements limit the amount of external capacity that can be relied upon to satisfy Zone 7 resource adequacy requirements, and available import capability can vary by season and planning year.

Q237. How are CCGT resources expected to operate within the MISO market?

A237. CCGT resources are dispatched economically in the MISO market based on fuel costs, variable operating costs, market energy prices, availability, and system conditions. CCGT resources typically exhibit highly efficient heat rates, which generally position them among the lower-cost thermal resources available to the system and support frequent economic dispatch when market conditions warrant.

Depending on market conditions and system needs, CCGT resources may serve a combination of baseload, intermediate-load, and reliability-support functions while providing substantial energy, capacity, resource adequacy, and reliability value. Their operational flexibility also allows them to respond efficiently to changing system conditions and to complement and support an increasing amount of renewable generation on the system. Witness Burgdorf provides additional detail regarding operation of the proposed resources within the MISO market.

Q238. For which proposed facilities is the Company requesting CON approval?

A238. The Company is requesting CON approval for two Company-owned CCGT projects selected through the 2025 All-Source RFP and included in the Company's PCA:

- Livingston County project – Natural Gas CCGT – DTE Electric – 1,400 MW[28]
- Monroe County project – Natural Gas CCGT – DTE Electric – 700 MW[29]

Q239. How do the proposed Livingston County project and Monroe County project relate to the Company's PCA?

A239. The proposed Livingston County and Monroe County projects were selected through the Company's 2025 All-Source RFP and are included in the PCA as part of the portfolio of resources needed to reliably and affordably serve customers. Approval of the requested CONs would provide the regulatory authorization and cost pre-approval necessary for the Company to proceed with development and construction of these projects' facilities consistent with the PCA evaluated in this

[28] Approximate nominal capacity
[29] Ibid.

case. As discussed throughout this testimony, the Livingston County project and Monroe County project represent the Company's proposed implementation of the need-for-power and resource-selection determinations for which it seeks Commission approval.

Q240. How does CCS fit into the Company's proposed CCGT resource strategy?

A240. The Company is proposing the Livingston County project and Monroe County project as CCGT resources designed to support the future integration of CCS. The projects are planned to begin commercial operation as CCGT facilities in 2031 and 2032, respectively, with CCS planned to be placed into service at both facilities in 2035.

This approach allows the Company to add the firm, dispatchable capacity and energy identified as needed in the near term while providing a pathway for the projects to support future compliance with Michigan's Clean Energy Standard. Witness Stansell provides additional detail regarding the projects' design and provisions for future CCS integration, and Witness Hajj provides additional detail regarding Clean Energy Standard compliance.

Q241. Why is the Company proposing to place CCGT resources into service before the planned implementation of CCS?

A241. The Company's need for firm, dispatchable capacity and energy occurs before CCS is planned to be placed into service. As discussed by Witness Manning, the Livingston County project and Monroe County project are needed to support resource adequacy and reliability beginning in 2031 and 2032, respectively. The

Company therefore proposes to place the CCGT resources into service when that need occurs while developing the projects as CCS-ready facilities to accommodate the planned implementation of CCS in 2035.

This phased approach allows the Company to address its near-term reliability and resource adequacy needs while sequencing CCS implementation as a subsequent phase in support of future Clean Energy Standard compliance. It also provides additional time for CCS technology, supporting infrastructure, commercial arrangements, and other CCS development activities to continue to develop and mature.

Witness Stansell provides additional detail regarding the projects' CCS-ready design and future CCS implementation pathway, and Witness Hajj provides additional detail regarding Clean Energy Standard compliance.

DTE Electric – Livingston County project

Q242. Please describe the proposed Livingston County project, including technology type, size, location, expected capacity, and expected commercial operation date.

A242. The proposed Livingston County project is a Company-owned, CCS-ready CCGT facility that would provide firm, dispatchable capacity and energy to serve DTE Electric customers. The facility is planned for Handy Township, Livingston County, Michigan, and would have an estimated nominal capacity of approximately 1,400 MW.

The Livingston County project is expected to achieve commercial operation by the end of 2031. The project is being developed as a CCS-ready facility that is prepared for a planned in-service of CCS in 2035 to support compliance with Michigan's Clean Energy Standard.

Witness Stansell provides additional detail regarding the project's site, technology, and design, and Witness Banks provides additional detail regarding its construction and execution schedule.

Q243. What is the ownership and contractual structure for the Livingston County project?

A243. The Livingston County project is proposed as a Company-owned, self-build resource. The Company is not proposing to acquire the Project through a third-party power purchase agreement or other long-term contractual structure. As discussed earlier in my testimony, the Company evaluated Company-owned and third-party resource alternatives through the 2025 All-Source RFP before selecting the Livingston County project.

Q244. Was the Livingston County project selected as a result of a competitive solicitation?

A244. Yes. As discussed earlier in my testimony, the Livingston County project was evaluated through the Company's 2025 All-Source RFP alongside other Company-owned and third-party resource proposals. The RFP evaluation considered pricing and non-pricing criteria and included oversight by an Independent Monitor. Based on the competitive evaluation and the Company's

IRP analysis, the Livingston County project was selected as part of the PCA. The Company's proposal for the Livingston County project is provided as confidential Exhibit A-4.20.

Q245. What are the expected operating characteristics of the Livingston County project?

A245. The Livingston County project will be a firm, dispatchable resource capable of responding to changing customer demand and system conditions. The project's two 1x1 combined-cycle trains will be capable of being started, operated, and maintained independently, providing flexibility in dispatching the facility and scheduling outages. The selected advanced-class combustion turbine (CT) technology also provides rapid startup, strong ramping capability, operation across a wide range of load conditions, and high thermal efficiency. Witness Stansell provides additional detail regarding the project's expected operating and performance characteristics.

Q246. How will natural gas fuel be supplied to the Livingston County project's CCGTs?

A246. The Livingston County project is located at the intersection of the Vector and Rover interstate natural gas pipelines, providing access to reliable natural gas supply while minimizing the need for new lateral pipeline infrastructure. The project will require the necessary interconnection, commercial, engineering, permitting, and construction arrangements to provide fuel to the facility. Witness Swiech provides additional detail regarding the site's access to natural gas

infrastructure and the Company's natural gas supply and transportation strategy for the project.

Q247. What is the expected heat rate of the Livingston County project's CCGTs?

A247. The Livingston County project is expected to operate at a nominal net heat rate of 6,500 Btu/kWh, with an expected range of approximately 6,200 to 6,600 Btu/kWh at full fired load across different seasonal conditions. This level of efficiency is consistent with modern advanced-class combined-cycle generation and reduces the amount of fuel required to produce electricity. Witness Stansell provides additional detail regarding the project's expected performance characteristics.

Q248. What ongoing maintenance and capital investment will be required to support reliable operation of the Livingston County project's CCGTs over its expected life?

A248. Like other CCGT facilities, the Livingston County project will require routine inspections, maintenance, refurbishment, and replacement of major components over its operating life. Major combustion turbine maintenance will be performed based on manufacturer requirements and operating history, including combustion, hot gas path, and major inspections. The project will also require periodic inspection and maintenance of the HRSGs, steam turbines, generators, and balance-of-plant equipment. Witness Stansell provides additional detail regarding the project's long-term maintenance requirements and associated cost assumptions.

Q249. What are the expected O&M costs for the Livingston County project?

A249. The Livingston County project is expected to incur both fixed and variable O&M costs associated with staffing, routine maintenance, major equipment maintenance, consumables, and other costs necessary to reliably operate the facility. Witness Stansell forecasts fixed plant O&M costs of approximately $15 million per year, including the O&M portion of the long-term service agreement, as well as variable O&M costs of approximately $1.60/MWh for unfired operation and an incremental $0.70/MWh for duct firing. These O&M estimates exclude natural gas fuel costs. Witness Stansell provides additional detail regarding the basis for these estimates.

Q250. What is the expected operating life of the Livingston County project?

A250. The Company has assumed an expected operating life of approximately 30 years for the Livingston County project. The project's Power Island Equipment was specified to support a 30-year design life, subject to routine inspections, maintenance, repairs, and replacement of major components as necessary. Witness Stansell provides additional detail regarding the basis for the project's expected operating life.

Q251. How does the Livingston County project support the Company's Clean Energy Plan and Clean Energy Standard compliance strategy?

A251. The Livingston County project is included in the Company's PCA, which is designed to comply with Michigan's Clean Energy Standard. The project is being developed as a CCS-ready resource, with CCS planned to be placed in service in 2035 to support Clean Energy Standard compliance. This phased approach allows the Project to provide needed firm, dispatchable capacity and energy beginning in

2031 while preserving the pathway for the facility to support the Company's longer-term clean energy requirements. Witness Hajj provides additional detail regarding Clean Energy Standard compliance, and Witness Stansell provides additional detail regarding the project's CCS-ready design.

Q252. Why do the size, fuel type, and other design characteristics of the Livingston County project represent the most reasonable and prudent means of meeting the Company's identified power need?

A252. The size, fuel type, and other design characteristics of the Livingston County project represent the most reasonable and prudent means of meeting the Company's identified power need because the project provides the firm, dispatchable capacity and energy needed to support resource adequacy and reliable service as the Company's generation portfolio transitions.

The project's approximately 1,400 MW capacity and CCGT technology provide a significant source of accredited capacity and efficient, dispatchable energy that can respond to changing customer demand and system conditions. The project's two 1x1 single-shaft combined-cycle trains also provide operational flexibility by allowing each unit to be operated and maintained independently.

The Company evaluated the project through the 2025 All-Source RFP and the 2026 IRP process, including consideration of alternative supply-side resources, demand-side resources, market purchases, and other resource options. Based on those evaluations, the Company determined that the Livingston County project's size, fuel type, and design characteristics provide the most reasonable and prudent

means of meeting the identified power need. Witness Manning provides additional detail regarding the Company's modeling and evaluation of resource alternatives, and Witness Stansell provides additional detail regarding the project's technology selection and design.

Q253. What site-related information supports the development of the proposed Livingston County project?

A253. Witness Stansell provides additional detail regarding the current use of the proposed Livingston County project's site, site control, site suitability, and related development considerations. At a summary level, the site was selected because it is well-positioned to support timely development of the proposed Livingston County project, including consideration of land availability, zoning, constructability, electric interconnection, fuel supply access, permitting feasibility, and integration with the Company's broader generation portfolio.

Q254. What socioeconomic and local community benefits are associated with the proposed Livingston County project?

A254. The Livingston County project is expected to provide local socioeconomic benefits associated with construction activity, permanent operations, local employment, tax revenue, and related economic development. The Company will continue to engage with local officials, residents, and other stakeholders as project development proceeds.

Q255. Is the Livingston County facility located within three miles of an Environmental Justice (EJ) community?

A255. No, the Livingston County project site is not located within 3 miles of any EJ communities identified at or above the 75th percentile in MiEJScreen.

Q256. What specific Commission approvals is the Company requesting for the Livingston County project?

A256. As described earlier in my testimony, three of the Company's six requested CON approvals are associated with the Livingston County project. Specifically, the Company is requesting that the Commission approve the following:

- **Livingston County project – Need for Power:** A determination that the power to be supplied as a result of the proposed construction of the Livingston County project is needed;
- **Livingston County project – Resource Selection:** A determination that the size, fuel type, and other design characteristics of the Livingston County project represent the most reasonable and prudent means of meeting that power need; and
- **Livingston County project – Cost and Financing:** A determination that the estimated capital costs of and financing plan for the Livingston County project, including the costs of siting and licensing the facility and the estimated cost of power from the facility, will be recoverable in rates from the Company's customers, subject to MCL 460.6s(4)(c). The specific capital cost estimate for which the Company seeks approval is $3,925 million, as supported by Witness Stansell and the Company's supporting exhibits. The requested capital cost approval does not include future CCS implementation costs, separately determined MISO transmission network upgrade costs, or Allowance for

Funds Used During Construction (AFUDC). The financing plan for this project is supported by Company Witness Uzenski.

DTE Electric – Monroe County project

Q257. Please describe the proposed Monroe County project, including technology type, size, location, expected capacity, and expected commercial operation date.

A257. The proposed Monroe County project is a Company-owned, CCS-ready CCGT facility that would provide firm, dispatchable capacity and energy to serve DTE Electric customers. The facility is planned for Milan Township, Monroe County, Michigan, and would have an estimated nominal capacity of approximately 700 MW.

The Monroe County project is expected to achieve commercial operation by the end of 2032. The project is being developed as a CCS-ready facility that is prepared for a planned in-service of CCS in 2035 to support compliance with Michigan's Clean Energy Standard.

Witness Stansell provides additional detail regarding the project's site, technology, and design, and Witness Banks provides additional detail regarding its construction and execution schedule.

Q258. What is the ownership and contractual structure for the Monroe County project?

A258. The Monroe County project is proposed as a Company-owned, self-build resource. The Company is not proposing to acquire the project through a third-party power purchase agreement or other long-term contractual structure. As discussed earlier in my testimony, the Company evaluated Company-owned and third-party resource alternatives through the 2025 All-Source RFP before selecting the Monroe County project.

Q259. Was the Monroe County project selected as a result of a competitive solicitation?

A259. Yes. As discussed earlier in my testimony, the Monroe County project was evaluated through the Company's 2025 All-Source RFP alongside other Company-owned and third-party resource proposals. The RFP evaluation considered pricing and non-pricing criteria and included oversight by an Independent Monitor. Based on the competitive evaluation and the Company's IRP analysis, the Monroe County project was selected as part of the Company's PCA. The Company's proposal for the Monroe County project is provided as confidential Exhibit A-4.20.

Q260. What are the expected operating characteristics of the Monroe County project?

A260. The Monroe County project will be a firm, dispatchable resource capable of responding to changing customer demand and system conditions. The project's 1x1 combined-cycle configuration provides operational flexibility, while the selected advanced-class combustion turbine technology provides relatively rapid startup, strong ramping capability, operation across a wide range of load

conditions, and high thermal efficiency. Witness Stansell provides additional detail regarding the roject's expected operating and performance characteristics.

Q261. How will natural gas fuel be supplied to the Monroe County project's CCGT?

A261. The Monroe County project is located approximately five miles from the NEXUS and ANR interstate natural gas pipelines. Natural gas supply will require a lateral interconnection to existing pipeline infrastructure, together with the necessary commercial, engineering, permitting, and construction arrangements. Witness Swiech provides additional detail regarding the site's access to natural gas infrastructure and the Company's natural gas supply and transportation strategy for the project.

Q262. What is the expected heat rate of the Monroe County project's CCGT?

A262. The Monroe County project is expected to operate at a nominal net heat rate of approximately 6,500 Btu/kWh, with an expected range of approximately 6,200 to 6,600 Btu/kWh at full fired load across different seasonal conditions. This level of efficiency is consistent with modern advanced-class combined-cycle generation and reduces the amount of fuel required to produce electricity. Witness Stansell provides additional detail regarding the project's expected performance characteristics.

Q263. What ongoing maintenance and capital investment will be required to support reliable operation of the Monroe County project's CCGT over its expected life?

A263. Like other CCGT facilities, the Monroe County project will require routine inspections, maintenance, refurbishment, and replacement of major components over its operating life. Major combustion turbine maintenance will be performed based on manufacturer requirements and operating history, including combustion, hot gas path, and major inspections. The project will also require periodic inspection and maintenance of the HRSGs, steam turbines, generators, and balance-of-plant equipment. Witness Stansell provides additional detail regarding the project's long-term maintenance requirements and associated cost assumptions.

Q264. What are the expected O&M costs for the Monroe County project?

A264. The Monroe County project is expected to incur both fixed and variable O&M costs associated with staffing, routine maintenance, major equipment maintenance, consumables, and other costs necessary to reliably operate the facility. Witness Stansell forecasts fixed plant O&M costs of approximately $10 million per year, including the O&M portion of the long-term service agreement, as well as variable O&M costs of approximately $1.60/MWh for unfired operation and an incremental $0.70/MWh for duct firing. These O&M estimates exclude natural gas fuel costs. Witness Stansell provides additional detail regarding the basis for these estimates.

Q265. What is the expected operating life of the Monroe County project?

A265. The Company has assumed an expected operating life of approximately 30 years for the Monroe County project. The Project's Power Island Equipment was specified to support a 30-year design life, subject to routine inspections,

maintenance, repairs, and replacement of major components as necessary. Witness Stansell provides additional detail regarding the basis for the project's expected operating life.

Q266. How does the Monroe County project support the Company's Clean Energy Plan and Clean Energy Standard compliance strategy?

A266. The Monroe County project is included in the Company's PCA, which is designed to comply with Michigan's Clean Energy Standard. The project is being developed as a CCS-ready resource, with CCS planned to be placed in service in 2035 to support Clean Energy Standard compliance. This phased approach allows the Project to provide needed firm, dispatchable capacity and energy beginning in 2032 while preserving the pathway for the facility to support the Company's longer-term clean energy requirements. Witness Hajj provides additional detail regarding Clean Energy Standard compliance, and Witness Stansell provides additional detail regarding the Project's CCS-ready design.

Q267. Why do the size, fuel type, and other design characteristics of the Monroe County project represent the most reasonable and prudent means of meeting the Company's identified power need?

A267. The size, fuel type, and other design characteristics of the Monroe County project represent the most reasonable and prudent means of meeting the Company's identified power need because the project provides the firm, dispatchable capacity and energy needed to support resource adequacy and reliable service as the Company's generation portfolio transitions. The project's approximately 700 MW capacity and CCGT technology provide a significant source of accredited capacity

and efficient, dispatchable energy that can respond to changing customer demand and system conditions.

The Company evaluated the project through the 2025 All-Source RFP and the 2026 IRP process, including consideration of alternative supply-side resources, demand-side resources, market purchases, and other resource options. Based on those evaluations, the Company determined that the Monroe County project's size, fuel type, and design characteristics provide the most reasonable and prudent means of meeting the identified power need. Witness Manning provides additional detail regarding the Company's modeling and evaluation of resource alternatives, and Witness Stansell provides additional detail regarding the project's technology selection and design.

Q268. What site-related information supports the development of the proposed Monroe County project?

A268. Witness Stansell provides additional detail regarding the current use of the proposed Monroe County site, site control, site suitability, and related development considerations. At a summary level, the site was selected because it is well-positioned to support timely development of the proposed Monroe County project, including consideration of land availability, zoning, constructability, electric interconnection, fuel supply access, permitting feasibility, and integration with the Company's broader generation portfolio.

Q269. What socioeconomic and local community benefits are associated with the proposed Monroe County project?

A269. The Monroe County project is expected to provide local socioeconomic benefits associated with construction activity, permanent operations, local employment, tax revenue, and related economic development. The Company will continue to engage with local officials, residents, and other stakeholders as project development proceeds.

Q270. Is the Monroe County facility located within three miles of an Environmental Justice (EJ) community?

A270. No. The Monroe County project's site is not located within 3 miles of any EJ communities identified at or above the 75th percentile in MiEJScreen.

Q271. What specific Commission approvals is the Company requesting for the Monroe County project?

A271. As described earlier in my testimony, three of the Company's six requested CON approvals are associated with the Monroe County project. Specifically, the Company is requesting that the Commission approve the following:

- **Monroe County project – Need for Power:** A determination that the power to be supplied as a result of the proposed construction of the Monroe County project is needed;
- **Monroe County project – Resource Selection:** A determination that the size, fuel type, and other design characteristics of the Monroe County project represent the most reasonable and prudent means of meeting that power need; and
- **Monroe County project – Cost and Financing:** A determination that the estimated capital costs of and financing plan for the Monroe County

project, including the costs of siting and licensing the facility and the estimated cost of power from the facility, will be recoverable in rates from the Company's customers, subject to MCL 460.6s(4)(c). The specific capital cost estimate for which the Company seeks approval is $2,518 million, as supported by Witness Stansell and the Company's supporting exhibits. The requested capital cost approval does not include future CCS implementation costs, separately determined MISO transmission network upgrade costs, or AFUDC. The financing plan for this project is supported by Company Witness Uzenski.

Approval of Projects

Q272. What risks did the Company evaluate with respect to the proposed Livingston County project and Monroe County project, and how did the Company assess those risks relative to alternative resource options?

A272. The Company evaluated risks related to combined cycle technology, project cost, development schedule, fuel supply, fuel price volatility, carbon emissions, environmental compliance, future Clean Energy Standard compliance, permitting, interconnection, and regulatory approval for the Livingston County project and Monroe County project.

The Company evaluated these risks through the 2026 IRP process as discussed in detail by Witness Manning, including portfolio modeling, resource adequacy analysis, evaluation of supply-side and demand-side alternatives, and a range of scenarios and sensitivities designed to assess how changes in key planning assumptions could affect resource need, portfolio performance, cost, and risk. The

Company also considered the risks associated with relying on market purchases, short-duration resources, intermittent resources, or delayed resource development to meet the identified need.

As discussed in Part V of my testimony, the Company also evaluated these risks through the 2025 All-Source RFP process. The proposed projects were compared against conforming bids received through the RFP, and bids were reviewed for key commercial, technical, cost, schedule, development, fuel, environmental, and execution considerations. This evaluation provided additional market information regarding available resource alternatives and helped the Company assess whether the proposed projects could reasonably support its identified capacity, energy, reliability, and compliance needs.

Based on these analyses, the risks associated with the proposed projects are reasonable because the Projects use proven combined cycle technology, are being advanced through a structured project-development process, and would provide firm, dispatchable capacity and energy needed to reliably serve customers. The projects are also designed as CCS-ready resources, which helps manage future carbon and Clean Energy Standard compliance risk while allowing the Company to address near-term reliability needs.

The risks associated with the proposed projects, discussed further below, are reasonable when compared with the reliability, cost, timing, and execution risks customers could face if the Company deferred these resources or relied on

alternatives that may not provide the same level of accredited capacity, dispatchability, duration, or operational control.

Q273. Why are the proposed resources reasonable and prudent compared to the alternatives evaluated?

A273. The proposed Livingston County project and Monroe County project are reasonable and prudent compared to the alternatives evaluated because the evaluated alternatives did not provide the same combination of firm capacity, sustained energy, dispatchability, operational control, and resource adequacy performance on the timing and scale required by the PCA. Those alternative resources, including intermittent resources, energy storage, and demand side resources, remain important components of the Company's PCA, but the Company's evaluation demonstrated that those resources, together with available market purchases, do not eliminate the need for firm, dispatchable capacity and energy.

The 2025 All-Source RFP also demonstrated the limited availability of alternative firm generation resources. Other than the Company's proposed Livingston County project and Monroe County project CCGT resources, the only qualifying firm generation resource bid into the RFP was the existing Michigan Power Cogeneration facility. No other qualifying third-party firm generation resources were offered through the solicitation. As discussed above, Michigan Power Cogeneration was selected as part of the PCA, but at 138 MW it does not provide sufficient capacity alone to satisfy the Company's identified need for firm, dispatchable generation. The remaining resource alternatives evaluated through

the RFP do not provide the same combination of firm generation, dispatchability, duration, and operational control as the proposed CCGT resources. Additional detail regarding the Company's modeling, portfolio comparisons, and comparative evaluation of resource alternatives is provided by Witness Manning, and Witness Brooks provides additional detail regarding the resource adequacy performance of the portfolios evaluated.

Q274. What would be the system reliability and cost impacts of not proceeding with the proposed resources?

A274. Not proceeding with the proposed Livingston County project and Monroe County project would increase reliability and cost risks for customers.

From a reliability perspective, without the firm, accredited capacity provided by the proposed projects, the Company would not have sufficient capacity available to meet its resource adequacy obligations and reliably serve customer load on the schedule reflected in the PCA. This would leave the Company with less firm, dispatchable capacity available during peak demand, periods of system stress, and times when intermittent or duration-limited resources are unavailable or limited. In addition, without timely replacement capacity, the planned retirement of Monroe Power Plant Units 1 and 2 could not proceed on the schedule reflected in the 2022 IRP Settlement Agreement and the 2026 IRP PCA.

From a cost perspective, not proceeding with the proposed projects could require greater reliance on market purchases or later procurement of replacement resources under less favorable cost and schedule conditions. Delaying the projects

would therefore increase customers' exposure to market, procurement, cost escalation, and schedule risks.

Additional detail regarding the modeled reliability and cost impacts of not proceeding with the proposed projects is provided by Witness Manning.

Q275. Is the Company seeking approval of the costs associated with future CCS implementation in this proceeding?

A275. No. The Company is seeking CON approval of the CCGT portions of the Livingston County project and Monroe County project. The requested capital cost approvals do not include the future costs associated with CCS implementation. The Company anticipates seeking the necessary Commission approvals associated with future CCS implementation in a future regulatory proceeding. Witness Stansell provides additional detail regarding the future CCS scope and associated development activities.

Q276. Why is cost pre-approval appropriate at this stage of project development, and how does timely approval support customers and the public interest?

A276. Cost pre-approval is appropriate at this stage because the proposed Livingston County project and Monroe County project are needed to support the Company's PCA and timely resource development to meet its system needs.

Large CCGT projects such as the Livingston County project and Monroe County project require long lead times for engineering, procurement, major equipment, permitting, contracting, construction, and commissioning. Cost pre-approval

provides regulatory certainty that enables the Company to continue advancing the projects on a schedule aligned with the Company's identified reliability and resource adequacy needs, including placing the projects into service in advance of approximately 1.6 GW of retiring dispatchable capacity. That certainty also supports the Company's continued execution of major equipment commitments and other project contracts, labor planning, financing, and management of the construction schedules for these highly complex Projects.

Without timely approval in this proceeding, customers could face increased reliability risk, cost escalation, schedule delays, and greater reliance on market purchases. Timely approval therefore helps protect customers by supporting disciplined project execution and the development of firm, dispatchable capacity and energy needed to support resource adequacy and reliable service during the generation transition. For these reasons, cost pre-approval reduces risks to customers, supports long-term customer value and reliability, and facilitates timely implementation of the Company's PCA.

Q277. How does the Company's request satisfy the applicable requirements of MCL 460.6s and align with the Company's IRP under MCL 460.6t?

A277. The Company's request satisfies the applicable requirements of MCL 460.6s by demonstrating the need for the power to be supplied by the proposed Livingston County project and Monroe County project, demonstrating that the size, fuel type, and other design characteristics of each Project represent the most reasonable and prudent means of meeting that power need, and providing the estimated capital costs and financing plan supporting the requested cost approvals for each project.

The Company has also evaluated the projects relative to alternative resource options and provided evidence addressing the projects' costs, risks, environmental compliance, competitive procurement process, development and execution, and other applicable considerations required for Commission approval under MCL 460.6s. Additional Company testimony addresses the use of a Michigan workforce to the extent practicable.

The requested CON approvals are also consistent with and supported by the Company's IRP under MCL 460.6t because the Livingston County project and Monroe County project are included in the PCA as resources needed to meet the Company's identified energy, capacity, and reliability needs. The Company evaluated the projects through the IRP modeling, portfolio analysis, resource adequacy, risk assessment, and competitive procurement processes described by the Company's witnesses. Taken together, the IRP and CON record support the Company's request that the Commission issue the six certificates of necessity associated with the Livingston County and Monroe County projects.

Witness Hajj provides additional detail regarding the applicable statutory and filing requirements and the Company's requested approvals. Exhibit A-1.2 identifies where the CON requirements are addressed in the Company's filing, and Exhibit A-1.5 explains the alignment between the Company's planning objectives and the applicable CON criteria. Witness Manning provides additional support regarding the IRP modeling, portfolio evaluation, and selection of the PCA.

Q278. Does this conclude your testimony?

A278. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road, Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Mechanical Engineering from The University of Michigan in 2005. I also received a Master of Business Administration Degree from Eastern Michigan University in 2016.

Q4. What is your professional experience?

A4. After receiving my Bachelor's degree from The University of Michigan in 2005, I was employed by Consumers Energy Company (Consumers Energy). During my initial employment at Consumers Energy, I worked in their production cost modeling group where I supported the development of power supply forecasts using the PROMOD® model as the basis. In 2009, I transferred positions into the Transmission and Regulatory Strategies Department. In this role, I was responsible for monitoring and analyzing filings by the Midcontinent Independent Transmission System Operator, Inc. (MISO) at the Federal Energy Regulatory Commission (FERC). I was also responsible for forecasting future transmission and certain energy market-related costs in Power Supply Cost Recovery (PSCR)

proceedings before the Michigan Public Service Commission (Commission or MPSC).

In 2012, I began my employment at DTE Electric within the Generation Optimization Department. In 2015, I was promoted to a Supervisor position and subsequently in October 2018, I was promoted to my current Manager position within Generation Optimization. In May 2025, I assumed responsibility as Manager over the Market Strategy & Settlements team within Generation Optimization.

Q5. What are your current duties and responsibilities?

A5. My current responsibilities include acquisition of wholesale electric power supply to reliably and economically serve the energy requirements of the Company's customers including: negotiation and administration of contracts; settlement of wholesale power market transactions; management of renewable energy credit inventory; management of resource adequacy processes and review; and advocacy of Company recommendations regarding proposed MISO rules, regulations, and business practices.

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. Yes, I have attended Utility Rate School and the Advanced Regulatory Studies Program, both hosted by the National Association of Regulatory Utility Commissioners (NARUC) and The Institute of Public Utilities at Michigan State

University. I also earned the certification of North American Electric Reliability Corporation (NERC) Balancing and Interchange Operator.

Q7. Have you previously sponsored testimony before the MPSC?`

A7. Yes. I sponsored testimony in the following cases:

U-16149	Consumers Energy's 2010-2011 Gas Cost Recovery (GCR) Plan
U-16485	Consumers Energy's 2011-2012 GCR Plan
U-16924	Consumers Energy's 2012-2013 GCR Plan
U-16890	Consumers Energy's 2012 PSCR Plan
U-17097-R	DTE Electric's 2013 PSCR Reconciliation
U-17319-R	DTE Electric's 2014 PSCR Reconciliation
U-17632	DTE Electric's 2013 Renewable Energy Plan Reconciliation
U-17680	DTE Electric's 2015 PSCR Plan
U-17793	DTE Electric's 2015 Amended Renewable Energy Plan
U-17804	DTE Electric's 2014 Renewable Energy Plan Reconciliation
U-17920	DTE Electric's 2016 PSCR Plan
U-17680-R	DTE Electric's 2015 PSCR Reconciliation
U-18111	DTE Electric's 2016 Amended Renewable Energy Plan
U-18082	DTE Electric's 2015 Renewable Energy Plan Reconciliation
U-18143	DTE Electric's 2017 PSCR Plan
U-17920-R	DTE Electric's 2016 PSCR Reconciliation
U-20069	DTE Electric's 2017 PSCR Reconciliation
U-20221	DTE Electric's 2019 PSCR Plan
U-20471	DTE Electric's 2019 Integrated Resource Plan
U-20561	DTE Electric's 2019 General Rate Case

Line No.		
1	U-20528	DTE Electric's 2020 PSCR Reconciliation
2	U-18091	DTE Electric's 2021 PURPA Avoided Cost
3	U-20836	DTE Electric's 2022 General Rate Case
4	U-21193	DTE Electric's 2022 IRP
5	U-21297	DTE Electric's 2023 General Rate Case
6	U-21534	DTE Electric's 2024 General Rate Case
7	U-21860	DTE Electric's 2025 General Rate Case
8	U-22046	DTE Electric's 2026 General Rate Case
9	U-22058	DTE 2026 Data Center Special Contracts

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support the Company's Integrated Resource Plan (IRP) and the proposed course of action (PCA) by providing:

- An overview of the resource adequacy requirements and capacity market;
- Support for the Company's existing capacity resources including Power Purchase Agreements (PPA) counted by MISO for planning year 2026/2027;
- An overview of demand response resource accreditation within MISO's resource adequacy construct;
- An overview of the effective capacity import limit (ECIL) for MISO Zone 7 and local reliability requirements;
- An overview of current MISO market-compensated Ancillary Services; and
- A description of the effect of the proposed Combined Cycle Gas Turbines (CCGTs) on wholesale market competition to meet the Certificate of Necessity (CON) requirements.

Q9. How did you support DTE Electric's IRP process for the PCA?

A9. As further described by Company Witness Manning and discussed later in my testimony, I verified that the assumptions related to the Company's existing capacity resources used in the various IRP modeling runs, starting point capacity position and the planning reserve margins were reasonable. I provided input on the more stringent requirements for and increased reliance on demand response (DR) resources within MISO. I also provided the calculation for the ECIL for MISO Zone 7 and discussed the risks of relying on external capacity imports.

Line No.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-5 (a)-(d)	NDA DTE Electric Existing Capacity Resources by Season
A-5.1	OMS DR-ER Reforms FERC Filing Intervention 5-06-2025
A-5.2	OMS-MISO Survey Results 6-04-2026
A-5.3	MISO PY26-27 PRA Results 4-28-2026

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.[1]

Q12. How is your testimony organized?

A12. My testimony consists of the following six parts:

Part I	Resource Adequacy Requirements and Capacity Market
Part II	Company's Existing Capacity Resources Including Power Purchase Agreements (PPA)
Part III	Demand Response (DR)/Load-Modifying Resources (LMRs) Accreditation in the MISO Resource Adequacy Construct
Part IV	Effective Capacity Import Limit (ECIL) for MISO Zone 7 and local reliability requirements
Part V	Current MISO Market-Compensated Ancillary Services
Part VI	Effect of the proposed CCGTs on wholesale market competition

[1] Exhibits 5.1, 5.2, and 5.3 were created under my supervision, however the content of the exhibits was created by multiple entities

PART I - RESOURCE ADEQUACY REQUIREMENTS AND CAPACITY MARKET

Q13. What regulatory requirements govern the Company's resource adequacy planning obligations?

A13. The Company's resource adequacy planning obligations are established through a combination of NERC reliability standards, MISO resource adequacy requirements, and Michigan law and regulations administered by the MPSC. Under the MISO tariff, the Company must satisfy MISO's resource adequacy requirements, which are informed by NERC reliability standards.

NERC Reliability Standard BAL-502-RFC-02 "Planning Resource Adequacy Analysis, Assessment and Documentation," requires Planning Coordinators to establish planning reserve margins and perform resource adequacy assessments for each planning year. MISO serves as the Planning Coordinator for the MISO footprint and is therefore responsible for establishing the planning reserve margin requirements applicable to load-serving entities within the region.

In addition, MCL 460.6w (PA 341) requires the Company to demonstrate annually that it owns or has contractual rights to sufficient capacity resources to satisfy its projected capacity obligations, including the planning reserve margin, on a four-year forward basis. This Michigan capacity demonstration requirement promotes longer-term planning beyond MISO's annual resource adequacy construct, which evaluates resource sufficiency on a one-year planning horizon as further discussed in my testimony.

Q14. How are capacity planning reserve margin requirements established by MISO?

A14. Each year, MISO establishes seasonal Planning Reserve Margins (PRMs), which are the amounts of capacity above the expected weather-normalized peak demand required to reliably serve load in the entire MISO region. A PRM is intended to maintain reliable operation while meeting unforeseen events such as extreme weather or unexpected capacity outages. The PRM is established by performing a Loss of Load Expectation (LOLE) study, which considers factors including, but not limited to: generator forced outage rates, generator planned outages, expected performance of load modifying resources, load forecasting uncertainty, and transmission system import and export capabilities. The PRM is established using a LOLE of 1 day per 10 years, which is a widely accepted industry reliability standard and is used by MISO.

Q15. How does MISO implement its resource adequacy requirements?

A15. Beginning in Planning Year (PY) 2023-2024, MISO's annual resource adequacy requirements were changed to seasonal with separate accredited capacity requirements and PRMs for summer, fall, winter and spring. Every year, Load Serving Entities (LSEs) in MISO are required to demonstrate compliance with their Planning Reserve Margin Requirement (PRMR), which is their forecasted peak demand (coincident with MISO's peak demand) plus the required PRM for each season. The PRMR compliance process is executed by MISO in the spring immediately prior to the PY that begins on June 1. MISO LSEs have several options to meet their PRMR through a combination of: submitting a Fixed Resource Adequacy Plan (an LSE's plan showing rights to sufficient resources to meet its

PRMR), purchasing capacity through MISO's Planning Resource Auction (PRA) at the same time as separately selling or self-scheduling (offering into the auction at a price of zero as a "price taker") any capacity they may own, or paying a capacity deficiency charge.

MISO's PRA does not guarantee the availability of capacity. In fact, a capacity shortage situation could arise because MISO's PRA is for a term of only one Planning Year, and it is performed only a few months prior to that Planning Year, whereas the planning and construction of new generating capacity can take several years. When LSEs properly plan for the long-term capacity needs of their customers, the PRA works as a balancing auction for the upcoming Planning Year by providing a means to buy and sell small amounts of capacity needed because of normal variances in load and generation. The PRA is principally a near-term balancing mechanism; it is not a substitute for long-term resource planning.

Q16. How does MISO implement local reliability requirements?

A16. MISO developed Local Resource Zones (LRZs) based on criteria including electrical boundaries, state boundaries, transmission interconnections and geographic boundaries. There are ten LRZs within MISO and the Company's service territory is in LRZ 7, which is comprised of most of the lower peninsula of Michigan. As part of MISO's annual LOLE study, the Capacity Import Limits (CIL) and Capacity Export Limits (CEL) of each LRZ are determined along with the Local Clearing Requirement (LCR), which is the minimum amount of unforced capacity (the amount of capacity assigned to a resource utilizing historic availability) that must be physically located within a LRZ. Simply stated, to

reliably serve load, a minimum amount of capacity must be located near the load due to the limitations of the transmission system to import additional capacity. When conducting the PRA, MISO enforces the LCRs, CILs and CELs using a multi-zone optimization methodology and commits capacity up to the PRM requirements of all LSEs.

Q17. What is the effective CIL or ECIL and the difference between CIL and ECIL?

A17. The CIL represents the maximum amount of capacity that transmission conditions would permit the zone to import. The ECIL represents the import amount the zone can actually rely upon after accounting for the LCR. It is calculated as PRMR minus LCR. Because both the LCR and PRMR must be enforced in the PRA to ensure a reliability of 1 day per 10 years LOLE, the actual amount of capacity that an LRZ can import can be materially constrained further than the CIL. This ensures that sufficient existing resources are committed, if available, in each LRZ to reliably serve load. The PRA Auction Clearing Price (ACP) is procedurally set to the maximum clearing price of the Cost of New Entry (CONE) when there is insufficient capacity to meet the LCR of a zone, or the total PRMR for a MISO subregion, for that planning year. CONE is an industry-wide term used to indicate the current, annualized capital cost of constructing a hypothetical advanced combustion turbine (CT).

Q18. How has MISO's annual resource adequacy construct changed from DTE Electric's previous IRP filing?

A18. MISO changed its resource adequacy construct from an annual to a seasonal approach (spring, summer, fall and winter), incorporated planned resource outages

that impact capacity accreditation (particularly for availability during tight system hours), implemented the Reliability Based Demand Curve (RBDC) for the PRA, and reformed the requirements and accreditation for demand response resources (discussed further in Part III). The seasonal approach is similar to the annual construct with a single PRA that solves each season. Each season has different CIL, CEL, LCR, local reliability requirement (LRR) and PRMR values as well as resource accreditation tied to the seasons. This impacts resource outage planning and provides a more granular focus on resource adequacy across the entire PY.

Beginning with PY 2025/2026, MISO implemented a Reliability Based Demand Curve in the PRA. MISO develops a separate downward-sloping demand curve for each season based on LOLE modeling. The curve produces higher capacity prices as the system approaches or falls below the applicable reliability level and lower prices when capacity exceeds that level. Over time, the design is intended to produce capacity-price signals that approach Net CONE near the target reliability level. Witness Manning further discusses how the IRP modeling accounts for ensuring year-round resource adequacy for DTE Electric customers.

Q19. How is MISO's resource adequacy construct changing in PY 2028/2029?

A19. MISO filed its new resource adequacy construct based on a Direct Loss of Load (DLOL) methodology with FERC in Docket ER24-1638 and received approval on October 25, 2024. The DLOL methodology ties planning reserve requirements and resource accreditation to the high-risk loss of load hours. This method better aligns the capacity accreditation for each resource based on the expected availability during the critical loss of load hours. Because both requirements and accreditation

will depend more heavily on performance during high-risk hours, accredited capacity may vary more from year to year, increasing uncertainty in forward capacity planning.

PART II – COMPANY'S EXISTING CAPACITY RESOURCES INCLUDING POWER PURCHASE AGREEMENTS

Q20. How are capacity resources recognized in meeting reliability requirements?

A20. MISO uses an unforced capacity (UCAP) based method to determine the amount of Seasonal Accredited Capacity (SAC) from a capacity resource to credit towards reliability requirements in each Planning Year. SAC is intended to represent the amount of capacity that is expected to be available for that resource during MISO's peak demand for each season based on its operating characteristics and historical performance.

SAC values for non-intermittent resources are currently calculated by reducing the resource's installed/tested capacity (ICAP) by its three-year historic availability (weighted towards Resource Adequacy Hours – tightest 3% of hours in each season based on MISO margin).

SAC values for non-wind intermittent resources, such as run of river hydro and solar, are based on the facilities' performance during specific seasonal peak hours. Accreditation is determined from average performance during hours ending 15, 16, and 17 for Summer, Fall, and Spring, and hours ending 8, 9, 19, and 20 for Winter. New solar generation facilities will be accredited using MISO's default capacity

credit represented as a percent of the installed capacity and published in MISO's Wind and Solar Capacity Report.

SAC values for existing wind generation facilities are based on a combination of MISO's Effective Load Carrying Capability (ELCC) probabilistic method and performance during peak hours. The ELCC represents the amount of incremental load a resource can serve, which is accomplished by comparing the LOLE of the system with the resource to the LOLE of the system without the resource. Performance is measured seasonally by the average generation during the top eight coincident system unique-day peak hours in each Planning Year over a period of the most recent three Planning Years. SAC is calculated by multiplying the seasonal wind ELCC percentage by the performance. New wind generation facilities receive the class-average seasonal wind capacity credit represented as a percent of installed capacity.

Load Modifying Resources in the form of DR reduce demand at the point of customer interconnection, SAC for DR is determined by increasing the interruptible demand by the Local Balancing Authority's transmission loss percentage as well as the MISO PRM.

Q21. What existing capacity resources did the Company commit to MISO for PY 2026/2027?

A21. Confidential Exhibit A-5 (a)-(d) shows the Company's existing capacity resources. The Company utilizes three types of resources to meet MISO Resource Adequacy requirements: Company-Owned Generation, DR, and Long-Term Power Purchase

Agreements including Behind the Meter Generation and bilateral contract capacity. The current Company-owned resources qualified for 9,746 MW of MISO Planning Resources in the summer season of the 2026/2027 PY using the SAC methodology. The Company's current DR resources qualified for 573 MW of MISO Planning Resources in the summer season of the 2026/2027 planning year and include the following demand response programs: 1) Tariff D1.1 Interruptible Space-Conditioning Service Rate, 2) Tariff D3.3 Interruptible General Service Rate, 3) Tariff D8 Interruptible Supply Rate, 4) Tariff R1.1 Alternative Electric Metal Melting, 5) Tariff R1.2 Electric Process Heat, 6) Tariff R10 Interruptible Supply Rider, 7) Tariff R12 Capacity Release and 8) Smart Savers (Bring Your Own Thermostat). The Company's current long-term PPAs qualified for 273 MW of MISO Planning Resources in the summer season of the 2026/2027 Planning Year and include both Public Utility Regulatory Policies Act (PURPA) and PA295/PA342 resources. The accredited value of capacity resources varies from year to year based on unit performance and MISO's SAC methodology.

Q22. How long does the Company project to purchase power from its Long-Term Power Purchase Agreements?

A22. Confidential Exhibit A-5 (a)-(d) shows the Company's Long-Term Power Purchase Agreements and the year in which each agreement terminates. However, for planning purposes and per the IRP filing requirements, the Company assumes that the current power purchase agreements, including PURPA contracts, will be renewed and continue as resources throughout the entire IRP time-period.

PART III - DEMAND RESPONSE/LOAD-MODIFYING RESOURCES ACCREDITATION IN THE MISO RESOURCE ADEQUACY CONSTRUCT

Q23. How are DR resources currently accredited under the MISO Resource Adequacy Construct?

A23. DR resources offered in the 2026/27 PY need a notification time of six hours or less and the DR resource must be capable of being interrupted for a minimum of five times in the summer, five times in the winter, three times in the spring, and three times in the fall to qualify as a Planning Resource for the respective season.

Q24. Do you anticipate any further changes to the DR accreditation?

A24. Yes, MISO filed FERC Docket ER25-1886, on April 4, 2025, and on June 18, 2026, FERC accepted tariff changes for LMRs that are expected to impact DTE Electric's LMR portfolio as further discussed by Witness Leuker. The major changes include: 1) notification time and associated deployment, 2) testing requirements, 3) meter data reporting, and 4) number of interruptions per season.

1) MISO will divide "emergency use only" LMRs into two types: Type I and Type II. The types are bifurcated by how quickly a LMR can respond to MISO's notifications, with Type I deploying within six hours of notification and Type II deploying within 30 minutes of notification. It is expected that Type I LMRs will be deployed more frequently as they will be deployed sooner in MISO's maximum generation emergency steps while Type II LMRs would still be made available but deployed later in the MISO emergency steps.

2) MISO will implement more stringent testing requirements for both LMR types. Type I will be required to test upon initial registration and only again if the amount of megawatts registered changes. Type II LMRs will be required to test annually. Testing will be done at random by MISO with limited "opt-out" provisions.

3) MISO will implement a requirement to submit meter data to determine LMR accreditation amounts. Accreditation will be based on actual availability during MISO's seasonal capacity advisory hours over the last planning year.

4) MISO will remove the limits on the number of interruptions (currently five times in summer and winter seasons and three times in fall and spring seasons) and to be available whenever an emergency is declared.

The effective date for all these changes in the Demand Response and Emergency Resources Reforms is September 1, 2027.

Q25. Are you concerned about current and future DR accreditation requirements having an impact on the ability to increase the level of DR resources in this IRP?

A25. Yes. As previously discussed, MISO has already made changes to demand response accreditation that require shorter notification times and increase the number of times that DR resources can be interrupted per year to receive full accreditation. Additionally, MISO has received FERC approval for changes to demand response

Line No.

accreditation aligned with availability during critical hours as well as introduced more severe non-performance penalties. These changes directionally make demand response less attractive for customers and may negatively influence future participation in DTE Electric's demand response programs. The Organization of MISO States (OMS) shares similar concerns in their ER25-1886 FERC filing comments (Exhibit A-5.1, page 6) stating, "OMS is aware that this set of reforms may reduce the amount of DR available to MISO while we are experiencing a constrained resource environment. These reforms may make running DR programs for Load Serving Entities ("LSEs") more burdensome, more costly, and more difficult to explain to participating customers, making operating such programs ultimately less attractive." As MISO changes future requirements intended to increase the access to and flexibility of DR resources, customers may no longer find participation in demand response programs as beneficial. See the direct testimony of Witness Leuker for additional information on DR programs.

Additionally, as the frequency of calls and the reliance on demand response increases, the performance of LMRs and DR resources will be critical to the Company's capacity position. Per the MISO Tariff, if a DR resource does not respond to a Scheduling Instruction "if deemed appropriate" by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year."[2] If that same DR resource does not respond for a second occasion, "the Demand Resource or BTMG will no longer qualify as an LMR and will not

[2] MISO Tariff Section 69A.3.9.a

receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year."[3] Most new generation resources take multiple years to be brought online, thus, disqualifications of demand response resources and/or customers dropping out of existing programs relied upon to meet resource adequacy targets, creates a reliability risk. As discussed by Witness Leuker, the Company will monitor customer participation and performance.

PART IV –EFFECTIVE CAPACITY IMPORT LIMIT FOR MISO ZONE 7 AND LOCAL RELIABILITY REQUIREMENTS

Q26. What was the PY 2026/2027 Zone 7 ECIL and how did it limit Zone 7 capacity imports?

A26. Based on MISO's resource adequacy requirements for PY 2026/27, 83%, 84%, 94%, and 77% of the PRMR applicable to load serving entities in Michigan Zone 7 must be supplied by resources located within the zone for the summer, fall, winter, and spring, respectively. For PY 2026/27 winter season, the Zone 7 ECIL was 939 MW (ECIL = PRMR – LCR = 15,628 – 14,689 = 939 MW using MISO PRA data published 4/28/26). Thus, while the capacity import limit was 4,123 MW, in reality, only 939 MW of resources external to Zone 7 were able to contribute to resource adequacy in Zone 7. The remaining resources needed to be located within Zone 7 to meet the LCR constraint.

[3] MISO Tariff Section 69A.3.9.b

Line No.

Q27. How has Zone 7 ECIL changed over the past four Planning Years and the percentage of PRMR needed to come from local resources?

A27. ECIL has been volatile over the last four Planning Years as shown in Table 1. Even though ECIL is volatile, the percentage of the PRMR (LCR divided by PRMR) needed to be served by local resources to meet reliability standards in recent years has not dropped below 80% for the summer season and was greater than 100% of PRMR in previous fall and winter seasons showing the importance of generation built within Zone 7.

Table 1: Seasonal Zone 7 Historical ECIL and percentage of local resources required by Planning Year (in MWs)

Summer	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27
Zone 7 ECIL[1]	2,447	2,294	1,547	3,607
Local Requirement as percentage of PRMR[2]	88.5%	89.4%	92.7%	82.8%
Fall	**PY 2023/24**	**PY 2024/25**	**PY 2025/26**	**PY 2026/27**
Zone 7 ECIL[1]	-298	450	2,298	3,154
Local Requirement as percentage of PRMR[2]	101.5%	97.7%	88.8%	83.6%
Winter	**PY 2023/24**	**PY 2024/25**	**PY 2025/26**	**PY 2026/27**
Zone 7 ECIL[1]	1,235	-231	623	939
Local Requirement as percentage of PRMR[2]	92.7%	101.3%	96.1%	94.0%
Spring	**PY 2023/24**	**PY 2024/25**	**PY 2025/26**	**PY 2026/27**
Zone 7 ECIL[1]	3,385	3,298	3,400	4,483
Local Requirement as percentage of PRMR[2]	82.2%	83.2%	82.9%	77.2%

1) Data from actual MISO PRA results

2) Local Requirement as percentage of PRMR calculated by dividing LCR by PRMR.

Q28. Do you have concerns about relying on imports and the ability to import capacity external to Zone 7?

A28. Yes. The values and volatility of the ECIL as shown in Table 1 create uncertainty of being able to rely on external capacity to meet resource adequacy requirements and present a reliability risk to Zone 7. The ECIL is not allocated to any particular LSE, thus there is no certainty around the amount of ECIL available. In addition, there is currently no local capacity requirement for individual LSEs. This creates uncertainty whether there will be enough local resources to meet the Zone 7 LCR as there is no obligation by individual LSEs to ensure their share of the local reliability criteria is met.

In addition, MISO has rules for external resources, such as those in Ontario, that ensure reliability. Ontario rules would need to change before it is prudent to count on those resources for reliability. Capacity from Ontario does not meet various MISO standards for External Resources and cannot be qualified as capacity resources. For External Resources to qualify for capacity credit under MISO's tariff, (1) the requester must demonstrate "that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border…of the Transmission Provider [MISO] Region,"[4] and (2) that "At its sole discretion, the Transmission Provider [MISO] may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency."[5] The Independent Electric System Operator ("IESO") does not grant the specified firm transmission service, nor does it comply

[2] MISO Tariff Module E-1 69A.3.1.c
[3] MISO Tariff Module E-1 69A.3.1.f

with the recall standards as established by MISO, thus disallowing its capacity from qualifying in the MISO construct.

Q29. Do you have concerns with increased costs of relying on resources external to Zone 7?

A29. Yes. Customers are exposed to potential additional capacity costs when using resources outside of Zone 7 to meet resource adequacy requirements. For example, when non-Zone 7 capacity is used, the Company would receive the Zonal Resource Credits (ZRCs) from this out of zone resource and use the ZRCs to meet its Zone 7 capacity requirement to serve customer demand. However, if the Zone 7 auction clearing price is CONE due to insufficient resources to meet the LCR, customers may be subject to a Zonal Deliverability Charge. This charge occurs when there is a difference in the auction clearing price between the MISO zone where the resource is located and the zone in which the LSE is located. In instances where the LCR is not met, this Zonal Deliverability Charge would be assigned to any load serving entity that is relying on resources outside the local zone even if that load serving entity had enough resources in the auction to cover its PRMR. Thus, under MISO's resource adequacy construct, it matters not only whether there are enough resources to meet the overall PRMR, but also where those resources are located.

Additionally, customers are also exposed to potentially excessive energy costs due to system congestion when resources are not located near the load. The cost to serve DTE Electric's customer load at the Company's load node (DECO.NEC) may not be offset by the market revenue (generator LMP) received by a generation

Line No.

resource located in another zone/area. This mismatch in cost/revenue can be large and is unpredictable.

Q30. Do you have any concerns about relying on resources external to Zone 7?

A30. Yes. As previously discussed, the ability to import capacity into Zone 7 is limited by ECIL and the ECIL value can swing significantly from year to year. **The volatility of ECIL (shown in Table 1) creates uncertainty that external resources to Zone 7 will be able to reliably meet resource adequacy requirements for DTE Electric customers**. There have even been seasons in the recent past where more than 100% of resources needed to be located locally (negative ECIL values). A negative ECIL indicates that the calculated LCR exceeded the zone's PRMR for that season; stated differently, satisfying the local reliability constraint required local capacity greater than the PRMR.

Not only is there uncertainty with the ECIL, but there may also not be enough resources available to import from other MISO zones even if the LCR is met and ECIL is not limiting capacity to meet the PRMR. This situation occurred in the 2022/23 Planning Year when Zone 7 was short 397 MWs to the PRMR and there were not enough external resources to import. This shortfall in Zone 7, combined with the overall capacity position of other zones, caused the MISO North/Central region PRA to clear at CONE. As many utilities shift to decarbonize their generation fleet as well as incorporate large load additions, it is not likely that there will be excess generation built due to MISO's 1-year capacity market and the need for utilities to meet their own requirement needs.

If external resources are unable to be imported or the LCR is not met, the probability of a loss of load event (an event in which available capacity is insufficient to serve demand) would not meet the reliability standards that govern the resource adequacy planning process. Additionally, in this scenario Zone 7 would clear at a capacity price of CONE so having resources locally mitigates this additional financial risk on DTE Electric customers.

Q31. What is the significance of Zone 7 and/or the MISO region exceeding reliability standards that govern resource adequacy?

A31. As previously discussed, Market Participants are required to meet an established PRMR to ensure that the 1 day in 10 years LOLE standard is met. In the event that this standard is not met, there is an increased probability of widespread outages due to insufficient resources to meet customer demand. Not meeting the reliability standard increases the likelihood of using DR resources and the risk of outages due to a lack of capacity in those regions.

Q32. Does the PCA provide adequate resources to meet DTE Electric's load ratio share of the forecasted LCR for Zone 7 for the summer season for the first five years?

A32. Yes. DTE Electric was able to forecast the LRR for the Zone 7 summer season by utilizing MISO indicative LRR percentages for Planning Year 2026/2027 and the forecasted annual Zone 7 MISO peak load. It was reasonable to only consider the summer season as the modeling performed by Witness Brooks only identified that season with a reliability risk (see Witness Brooks testimony). DTE Electric held the PY 2026/2027 CIL value flat to develop corresponding summer season LCRs

Line No.

for PYs 2026 through 2031. The comparison of the PCA resources to DTE Electric's load ratio share of the LCR is shown in Table 2.

Table 2: Zone 7 Forecasted Summer LCR Capacity Position by Planning Year (in MWs)

	Summer	PY 2027/28	PY 2028/29	PY 2029/30	PY 2030/31	PY 2031/32
(a)	LRZ7 LRR	25,092	25,550	26,498	28,261	29,094
(b)	LRZ7 CIL	4,628	4,628	4,628	4,628	4,628
(c)=(a)-(b)	LRZ7 LCR	20,464	20,922	21,870	23,633	24,466
(d)	LRZ7 Peak Forecast	21,324	22,092	22,911	24,436	24,851
(e)	DTE LRZ7 Coincident Peak Forecast (ZCPF)	10,544	11,331	11,838	11,688	11,604
(f)=(e)/(d)	DTE Load Ratio Share	49.4%	51.3%	51.7%	47.8%	46.7%
(g)=(c)*(f)	DTE LCR Allocation	10,118	10,731	11,300	11,304	11,424
(h)	PCA LRZ7 Resources (ZRCs)	11,306	11,604	11,706	11,843	12,117
(i)=(h)-(g)	**DTE LRZ7 LCR Capacity Position**	**1,188**	**873**	**406**	**539**	**693**

The results show that DTE Electric's PCA will meet its LCR for Zone 7 ensuring that local reliability is being properly planned for by DTE Electric. Thus, the PCA is reasonable and prudent from a reliability perspective.

Q33. Do you have any other concerns about the timing of the generation transformation and large load additions occurring across MISO and sustaining reliability over the next five years?

A33. Yes. Capacity projections from the 2026 OMS-MISO Survey show an increasing deficit of resources needed to meet reliability requirements if new resources are not brought online timely (Exhibit A-5.2, slides 8 and 9). In the Survey Results on slide 2, OMS stated, "To support rising demand, the region needs to maintain the

increased pace of capacity additions." MISO made a similar statement in the results of the PY 2026/27 PRA (Exhibit A-5.3, slide 2) asserting, "New generation capacity is coming online, but faster resource additions are still needed to support large load growth and ensure resource adequacy." Therefore, it is critical to properly plan for new generation assets to come online well in advance of any planned retirements to avoid further increase in reliability risk to DTE Electric customers. From a pure economic sense, new generation would ideally come online at the exact same time as other generation is retired, however, this poses a substantial risk to reliability when there is no longer generation in excess of requirements available across MISO.

PART V – CURRENT MISO MARKET-COMPENSATED ANCILLARY SERVICES

Q34. Can you identify the compensation mechanisms for ancillary services that are currently recognized by MISO?

A34. Yes. Ancillary services receive compensation either through the MISO market or through a MISO tariff.

Ancillary services that currently receive compensation in the MISO market consist of five products (Regulating Reserve, Spinning Reserve, Supplemental Reserve, Ramp Capability, and Short-Term Reserve), which provide the ability to respond in real time to equipment failures, load forecast uncertainty, and fuel shortages. Refer to Witness Manning for discussion on incorporation of regulation and spinning reserve markets in the IRP.

Q35. Can you describe each of the ancillary service products MISO administers?

A35. MISO administers Day-Ahead and Real-Time markets for Ancillary Services where each of the five products is bought and sold. Regulating Reserve is the ability of generating resources to raise or lower output to follow the moment-by-moment change in demand and frequency. Spinning Reserve is synchronized unloaded resource capacity set aside to be available to immediately offset deficiencies in energy supply that result from a resource contingency or other abnormal event. Supplemental Reserve is unloaded (possibly off-line) resource capacity set aside to be fully available within the Contingency Reserve Deployment Period to offset deficiencies in energy supply that result from a resource contingency or other abnormal event. Short-Term Reserve is the ability of online generating resources to raise or lower output within 30 minutes and offline generating resources to reach their economic minimum output within 30 minutes to meet market-wide, sub-regional and local flexibility needs. Ramp Capability is used to reduce the occurrence of energy and reserve scarcity by reserving ramping capacity for future load variations and uncertainty.

Q36. Is MISO planning to create any new market products or requirements to address future reliability concerns as the generation transformation continues across the MISO system?

A36. Yes. MISO is actively engaging stakeholders about concerns over resources having the right attributes needed to operate the system. Preliminary discussions are taking place to develop new market products or requirements in light of the large load integrations and impacts on the system. MISO intends to develop and refine

potential new products or requirements in the near term to address reliability concerns through its Large Load Working Group.

PART VI – EFFECT OF THE PROPOSED CCGTS ON WHOLESALE MARKET COMPETITION

Q37. Is the Company requesting a CON for any projects in this filing?

A37. Yes. As discussed by Witness Pratt, the Company is seeking CON approvals for two proposed carbon capture and storage (CCS)-enabled CCGT facilities – the Livingston County project and the Monroe County project.

Q38. Does the Company believe the two new CCGTs will have an adverse impact on wholesale market competition?

A38. No. The Livingston County project and the Monroe County project facilities will not create adverse impacts on wholesale market competition, and I will explain further why there is no concern over market power.

Q39. How does participation in the MISO wholesale markets mitigate any potential market power concerns?

A39. MISO is the entity that ultimately controls commitment and dispatch of all resources based on economics and reliability. In addition, the Independent Market Monitor (IMM) monitors all DTE resource offers and applies the market-monitoring provisions established in the MISO tariff. The operational decision-making by MISO and oversight by the IMM help alleviate market power concerns with the proposed CCGTs.

Q40. How does DTE Electric plan to operate the proposed CCGTs?

A40. The proposed CCGTs will be offered into the Day-Ahead and Real-Time Energy and Ancillary Service markets similar to most other DTE Electric generation resources. The CCGTs will also participate in the MISO capacity market through the annual PRA. By participating in the MISO wholesale markets, the IMM has oversight through MISO's FERC approved tariff on DTE Electric's resource offers to ensure there is no intentional market manipulation.

Q41. Do the proposed CCGTs represent a significant portion of the overall resource portfolio in MISO?

A41. No. The proposed CCGTs amount to 1,374 MWs for the Livingston County facility and 687 MWs for the Monroe County facility, representing less than 1.5% of the resources within MISO. The relatively small size of the CCGTs compared to the overall resource amount in MISO would have negligible impacts on the wholesale market prices, thus limiting any concerns over market power. By way of comparison, under FERC's wholesale market share indicative screen—one of two screens FERC uses under its market-based rate program to assess horizontal market power—a seller whose capacity share of the relevant market equals or exceeds 20% in any season fails the screen and is presumed to possess market power, requiring further mitigation or a more detailed analysis.[6] Given that the proposed CCGTs represent only a small fraction of MISO's total resources, the addition of this capacity poses no meaningful risk of DTE Electric approaching this threshold. Additionally, the increase in capacity of ~2,100 MWs for the CCGTs is

[6] *See* 18 C.F.R. § 35.37(c)(1) (2026); Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 89 (2007).

less than ~2,800 MWs being retired at the Monroe Power Plant, thus decreasing DTE Electric's market power.

Q42. Do the proposed CCGTs restrict access to competition in the wholesale markets?

A42. No. The proposed CCGTs would not restrict access for any other party to build a project and participate in the MISO wholesale markets.

In addition, as described by Witness Pratt, the proposed CCGT resources were selected through a competitive solicitation process. This competitive solicitation, the 2025 All-Source RFP, complied with the MPSC's competitive procurement guidelines, was overseen by a third-party independent monitor, and included participation by many third-party developers.

Q43. Does this complete your direct testimony?

A43. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JUSTIN J. W. BROOKS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JUSTIN J. W. BROOKS

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Justin Jeffrey Whitaker Brooks. My business address is 3000 Riverchase Galleria, Suite 3 575, Hoover, AL 35244. I am employed by PowerGEM as the Director of Strategic Energy and Risk Valuation Model (SERVM) Product. PowerGEM is a software and consulting firm that provides expertise in numerous areas including resource planning and resource adequacy to utilities across the United States.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q3. What is your educational background?

A3. I graduated from North Carolina State University with a Bachelor of Science in Nuclear Engineering. In addition, I received a Master of Science from Virginia Commonwealth University in Mechanical and Nuclear Engineering.

Q4. Do you hold any certifications or are you a member of any professional organizations?

A4. Yes. I am a registered Professional Engineer in North Carolina.

Q5. What is your professional experience?

A5. In 2012, I joined Newport News Shipbuilding where I performed various duties across numerous naval platforms related to radiation shielding and the safe engineering and conduct of radiological work. In 2017, I joined the Naval Nuclear Laboratory where I performed various duties related to the engineering of safety

systems in support of the Naval Nuclear Propulsion Program. In 2019, I joined Duke Energy where I developed and led the in-house resource adequacy analysis program for all three company jurisdictions using PowerGEM's SERVM. In that role I conducted analyses in support of the 2021, 2022, and 2023 Duke Energy Carolinas and Duke Energy Progress Integrated Resource Plans for North and South Carolina. In 2024, I joined Astrapè Consulting, now PowerGEM[1], as a Managing Consultant.

Q6. What are your current duties and responsibilities?

A6. As the Director of SERVM Product at PowerGEM, I am the product owner and engineering manager for SERVM. I also continue to assist clients by providing training and consulting services.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in the following cases:

Case No.	Description
U-22058	DTE Electric for Approval of Special Contracts

Q8. Please provide a summary of your and your firm's expertise performing this type of analysis.

A8. I have performed and supervised resource adequacy and capacity accreditation studies for various clients over the past six years, both with Duke Energy and PowerGEM. In addition, I have been involved with various industry task groups

[1] PowerGEM acquired Astrapé Consulting in 2024

Line No.

such as the Electric Power Research Institute's (EPRI) "Resource Adequacy for a Decarbonized Future" project, Energy Systems Integration Group's "Redefining Resource Adequacy" taskforce, the SERC Reliability Corporation's Resource Adequacy Working Group, and the North American Electric Reliability Corporation Probabilistic Assessment Working Group.

PowerGEM has performed resource adequacy and capacity accreditation analyses for various entities across the country for over 20 years. A non-exhaustive list includes utilities such as DTE Electric, Ameren, Associated Electric Cooperative, Central Louisiana Electric Co-Op, Dominion Energy South Carolina, Duke Energy Carolinas, Duke Energy Progress, Entergy, Georgia System Operations Corporation, Louisville Gas & Electric, Santee Cooper, Southern Company, and the Tennessee Valley Authority. Some of the Independent System Operator and Regional Transmission Organizations include Alberta Electric System Operator (AESO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP).

Line No.

Purpose of Testimony

Q9. What is the purpose of your testimony?

A9. The purpose of my testimony is to explain the methodology and results of the resource adequacy analysis performed at the Company's request to support DTE Electric's 2026 Integrated Resource Plan (IRP) filing. My testimony is organized into the following two parts:

Part I	Resource Adequacy Analysis Overview
Part II	Resource Adequacy Analysis Results

Q10. What is your role in conducting the resource adequacy analysis?

A10. I led the PowerGEM team that conducted the resource adequacy analysis. I participated directly in the analysis and supervised the work performed by other PowerGEM team members. Throughout this testimony, the term "PowerGEM" refers to the PowerGEM team that performed the analysis under my direction.

Q11. Are you sponsoring any exhibits in this proceeding?

A11. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-6	Justin J. W. Brooks CV
A-6.1	DTE 2026 IRP Electric Resource Adequacy Assessment

Q12. Were these exhibits prepared by you or under your direction?

A12. Yes, they were.

Line No.

Part I: Resource Adequacy Analysis Overview

Q13. What is resource adequacy?

A13. Resource adequacy is the ability of the electric system to maintain sufficient resources available to serve customer demand, including during periods of system stress.[2]

Q14. How does MISO establish resource adequacy requirements?

A14. MISO, under its Federal Energy Regulatory Commission (FERC) approved tariff, establishes resource adequacy requirements intended to ensure that sufficient capacity is available to serve forecasted demand plus the applicable Planning Reserve Margin (PRM). Load Serving Entities (LSE), including utilities such as DTE Electric, must demonstrate compliance with those requirements.

Q15. How does the Company demonstrate compliance with MISO's resource adequacy requirements?

A15. MISO establishes a PRM, which is the amount of capacity, expressed as a percentage of expected weather-normalized peak demand, that is required above that expected peak demand to satisfy the applicable resource adequacy criterion. That criterion is commonly described as one day containing at least one hour of firm load shed in ten years. Firm load shed refers to an interruption of electric service to customers when available generation and imports are insufficient to serve firm customer demand. The PRM is added to the Company's forecasted coincident peak demand to calculate its Planning Reserve Margin Requirement (PRMR). The Company demonstrates compliance with MISO's capacity planning requirement by

[2] Reliability Explainer, available at https://www.ferc.gov/reliability-explainer, accessed on August 26, 2026.

demonstrating sufficient accredited capacity to satisfy the PRMR. Witness Burgdorf provides further explanation of MISO's resource adequacy requirements, the Company's PRMR, and the accreditation of the Company's resources in his testimony.

Q16. How does the resource adequacy study performed by PowerGEM differ from the methodology used to determine the Company's PRMR?

A16. The two analyses serve different but complementary purposes. The PRMR is a capacity planning requirement that compares the Company's accredited capacity with its forecasted coincident peak demand plus the applicable planning reserve margin. PowerGEM's resource adequacy analysis is a separate probabilistic evaluation of selected resource portfolios using the SERVM model. The SERVM analysis evaluates the portfolios against a Loss of Load Expectation (LOLE) criterion of 0.10 event-days per year under numerous combinations of weather conditions, load uncertainty, and generator performance.

Q17. Can you describe the SERVM model used in the resource adequacy analysis?

A17. Yes. SERVM is a chronological electric system simulation model used to evaluate resource adequacy across thousands of simulated system conditions. SERVM also has full production cost modeling capabilities, although PowerGEM did not use the model in this analysis to calculate or report production cost results. To perform the resource adequacy analysis, SERVM used a multi-pass process to simulate the hourly, chronological commitment and dispatch of system resources and calculate reliability metrics for each simulation.

Line No.

By evaluating system performance across numerous combinations of weather, load uncertainty, and generator performance, SERVM produces a distribution of potential outcomes from which expected resource adequacy metrics can be calculated. Those results provide information regarding the frequency, duration, and magnitude of potential events during which available resources would be insufficient to serve firm customer demand.

Q18. What metrics are used to evaluate whether a resource portfolio is resource adequate?

A18. The standard metric used to evaluate the resource adequacy of a resource portfolio is LOLE. LOLE is the expected number of event-days per year on which available resources are insufficient to serve firm customer demand. LOLE is the most commonly used resource adequacy criterion in the United States. The Company's threshold for LOLE is specified by MISO Tariff Module E-1[3] to be one day with one or more hours of firm load shed every ten years due to a shortage of generation capacity. This is more commonly referred to as either 0.1 LOLE or "one day in ten."

The resource adequacy results also provide other informative, but not determinative, metrics including:

- Expected Unserved Energy (EUE) – The total expected amount of unserved energy in the year measured in MWh.
- Normalized Expected Unserved Energy (nEUE) – The EUE divided by total annual energy demand, expressed in parts per million (ppm).

[3] Module E-1 – Resource Adequacy, available at https://docs.misoenergy.org/miso12-legalcontent/Module_E-1_-_Resource_Adequacy.pdf, accessed August 26, 2026.

- Loss of Load Hours (LOLH) – The expected number of individual hours with firm load shed per year.

Q19. Can you describe the differences between capacity expansion modeling and resource adequacy modeling?

A19. Yes. Capacity expansion modeling and resource adequacy modeling serve different but complementary purposes in long-term planning. Capacity expansion modeling is a deterministic analysis that identifies least-cost portfolios to meet a utility's forecasted peak demand plus the required PRM over long-term time horizons. Capacity expansion modeling typically assumes normal weather conditions, expected load growth and average generator performance. Because it is designed to optimize under normal conditions, capacity expansion modeling does not capture operational risks that occur due to normal variations in weather and generator performance.

Resource adequacy modeling, on the other hand, is a probabilistic type of analysis. The SERVM tool stochastically stress tests the proposed resource portfolios from the capacity expansion model in future study years to evaluate whether the portfolios will satisfy the 0.1 LOLE resource adequacy criterion even under a wide range of future scenarios. SERVM generates a large distribution of future scenarios to ensure a representative sample from which to assess whether the DTE Electric system is adequate. This type of modeling incorporates variations and risks such as:

(1) Extreme weather and its impact on both load and resources

(2) Economic load forecast uncertainty

(3) Generator performance uncertainty

Witness Manning provides additional information regarding the Company's capacity expansion modeling and explains how the capacity expansion and resource adequacy analyses were used together in the IRP process.

Q20. Did you model proposed capacity additions and retirements for the Company using the resource adequacy analysis as described?

A20. Yes. The Company requested a resource adequacy evaluation of its preliminary proposed course of action (preliminary PCA) and four other portfolios for the 2029 and 2033 study years. Witness Manning describes the development and composition of those portfolios and explains why the Company selected 2029 and 2033 for the resource adequacy analysis.

Q21. Why were only two study years evaluated?

A21. Resource adequacy modeling is highly data and computing intensive, making simulations for every year of the 20-year IRP planning period impractical. Broad time horizon simulation also provides limited incremental value given similarity between years and the rate of change of the system being modeled. The best practice is to focus on key years defined by major changes in the load and/or generation fleet. It is generally more informative and efficient to focus on years where meaningful changes to the resource portfolio are expected rather than evaluating numerous closely spaced years that are likely to produce similar results. Refer to the testimony of Witness Manning for why the Company selected 2029 and 2033 for analysis.

Q22. Can you describe the framework for the resource adequacy analysis PowerGEM performed?

A22. Yes. PowerGEM modeled the DTE Electric system together with MISO Local Resource Zones (LRZs) 1 through 6 and the portion of LRZ 7 outside DTE Electric's system. For each portfolio and study year, the analysis evaluated the DTE Electric system using 44 historical weather years from 1980 through 2023, five levels of economic load forecast uncertainty (-4%, -2%, 0%, 2%, and 4%), and a minimum of 120 stochastic simulations of generator performance. All told, this resulted in 26,400 chronological hourly resolution scenarios evaluated for each portfolio and study year. The resulting probabilistic weighted average, or expected value, is the "final" result of the analysis.

Q23. Why did PowerGEM use historical weather data from 1980 through 2023?

A23. Best practice in resource adequacy analysis calls for evaluating the system against as many potential weather conditions as possible. Using historical data from 1980 through 2023 provides a robust sample of complete, reliable data.

Q24. Why did PowerGEM evaluate five levels of economic load forecast uncertainty?

A24. Customer demand may differ from the base load forecast because of economic and other forecast uncertainty. Evaluating multiple load forecast levels allows the resource adequacy analysis to measure how portfolio performance changes if customer demand is higher or lower than forecasted. These five levels (-4%, -2%, 0%, 2%, and 4%) represent the standard set of economic load forecast uncertainty scenarios that PowerGEM uses to assess sensitivity to bulk load forecast variability.

Line No.

Part II: Resource Adequacy Analysis Results

Q25. Which candidate portfolios did PowerGEM analyze?

A25. The Company requested that PowerGEM evaluate the following candidate portfolios:

- Preliminary PCA
- Base
- Non-Dispatch
- No Battery Constraints
- No Build

Witness Manning provides an overview of each portfolio in her testimony.

Q26. What were the results of the resource adequacy analysis for the Company's preliminary PCA?

A26. The resource adequacy analysis for the preliminary PCA portfolio resulted in LOLEs of 0.07 in 2029 and 0.20 in 2033.

Q27. Did the preliminary PCA satisfy resource adequacy?

A27. No. For study year 2029, the preliminary PCA portfolio meets the planning criterion of 0.1 LOLE. However, for study year 2033, the portfolio was resource inadequate, indicating elevated risk of capacity shortfalls resulting in unserved energy during periods of system stress.

Q28. How did the other four portfolios perform in the resource adequacy analysis?

A28. Similar to the preliminary PCA, each of the other four portfolios also met the resource adequacy criterion in 2029[4]. However, in 2033, all four portfolios failed to meet the resource adequacy criterion. Among the portfolios evaluated, the preliminary PCA demonstrated the strongest performance under the analysis. The LOLE results for each portfolio and study year are displayed in Table 1 below.

Table 1 DTE 2026 IRP Candidate Portfolio LOLE Results

Scenario Name	2029 Study Year	2033 Study Year
REF26_BASE	0.08 - PASS	0.21 - FAIL
REF26_NON_DISPATCH	0.07 - PASS	0.69 - FAIL
REF26_NO_BAT_CONST	0.08 - PASS	0.45 - FAIL
REF26_NO_BUILD	0.08 - PASS	1.12 - FAIL
REF26_PRELIM_PCA	0.07 - PASS	0.20 - FAIL

Q29. How did the preliminary PCA perform under the other metrics discussed?

A29. Table 2 below details the preliminary PCA's performance under the other metrics discussed: EUE, nEUE, and LOLH.

Table 2 Preliminary PCA Resource Adequacy Metrics

Metric	2029 Value	2033 Value	Unit
EUE	79	141	MWh/year
nEUE	1.30	2.33	ppm
LOLH	0.17	0.34	Event-hours/year

[4] REF26_NO_BAT_CONST and REF26_NO_BUILD have the same build plan in study year 2029 as REF26_BASE and were not separately analyzed.

Q30. When was the modeled resource adequacy risk most concentrated?

A30. The modeled resource adequacy risk was concentrated in the summer season in MISO Local Resource Zone 7 (LRZ 7), particularly during July from hour ending 20 through hour ending 23[5]. As shown in Table 1, study year 2033 presents more resource adequacy risk than 2029.

Q31. What resource characteristics contribute to improved resource adequacy performance?

A31. From a resource adequacy perspective, a diverse mix of resources enhances reliability by allowing the limitations or underperformance of one resource type, such as reduced solar output on a cloudy day or lower wind generation during a wind lull, to be offset by another resource, including dispatchable generation. When discussing any portfolio, it is important to evaluate the potential risks to the system. For example, a system which relies heavily on storage requires excess energy to store, or a system which heavily relies on thermal generation requires adequate and potentially redundant fuel supply.

A portfolio containing resources with complementary operating characteristics mitigates these resource-specific risks by reducing reliance on any one resource type or operating condition. Probabilistic resource adequacy analysis is an important part of the IRP process because it evaluates how the resources in a portfolio perform together across numerous combinations of weather, load, and generator-performance conditions.

[5] U-22168 Exhibit A-6.1 Figures 2-1 through 2-3.

Q32. What conclusions about the Company's preliminary PCA did you draw from your resource adequacy analysis?

A32. The resource adequacy analysis showed that the preliminary PCA meets the resource adequacy requirement for the 2029 study year. However, in study year 2033, the portfolio was not resource adequate, displaying an increased risk of firm load shed.

Q33. Is there another measure that can be used to quantify how much additional capacity would be required to make the preliminary PCA resource adequate in study year 2033?

A33. Yes. To quantify this, I added "perfect capacity" to the preliminary PCA portfolio until it was brought to the 0.1 LOLE resource adequacy target.

Q34. What is perfect capacity, and what did the SERVM modeling identify as the perfect capacity need for the preliminary PCA in 2033?

A34. Perfect capacity (also referred to as PCAP) is defined as dispatchable capacity with no outages (100% availability). It is used as a communication tool to quickly quantify the gap between a candidate portfolio's resource adequacy performance and the applicable reliability criterion, in this case 0.1 event-days per year. This allows resource planners to compare very different technologies on a common basis, determine how much new capacity is needed to maintain resource adequacy (via 0.1 LOLE, or other reliability metrics depending on jurisdiction), and understand how resource mixes affect the probability of outages. The modeling identified a need of 600 MW of perfect capacity in the preliminary PCA to bring the DTE Electric system back to 0.1 event-day per year LOLE.

Q35. Does perfect capacity represent an actual generating resource or technology?

A35. No. It is simply a communication tool enabling us to quickly determine the smallest amount of capacity required to bridge the delta between the candidate portfolios' expected reliability and the target. Once the "perfect capacity" amount is established, the resource planners use their tools to determine the appropriate "real-world" resource(s) to meet the standard. Witness Manning explains how the Company used the resource adequacy results, together with the other IRP analyses, to revise and evaluate the preliminary PCA.

Q36. Did the Company revise its preliminary PCA portfolio after considering the resource adequacy results?

A36. Yes. The Company provided PowerGEM with a revised preliminary PCA that included the portfolio changes described by Witness Manning. PowerGEM then evaluated the revised preliminary PCA using SERVM.

Q37. What did the resource adequacy analysis show for the revised preliminary PCA in the 2033 study year?

A37. The Company's revised preliminary PCA is resource adequate with a 0.09 event-day per year LOLE (Exhibit A-6.1). Other resource adequacy metrics are detailed in Table 3, which represent improvements from the preliminary PCA's 2033 results.

Line No.

Table 3 Other Resource Adequacy Metrics

Metric	2033 Value	Unit
EUE	53	MWh
nEUE	0.87	ppm
LOLH	0.14	Event-hour per year

Q38. Were climate impacts or extreme weather considered in the resource adequacy analysis?

A38. Yes. The full probabilistic SERVM analysis included 44 historical weather years and therefore incorporated a broad range of weather conditions. The Company also requested a separate sensitivity that isolated selected higher-risk summer and winter weather years to evaluate the revised preliminary PCA under those conditions. Because the selected weather years were already included in the full 44 weather year analysis, the sensitivity did not introduce new weather years. Instead, it separately examined the model outputs associated with selected higher risk weather conditions.

Q39. What requirements were imposed on the Company for this extreme weather analysis?

A39. Per the published IRP filing requirements in Case Nos. U-21570 and U-21867, page 6, PDF page 113:

> *"The utility shall provide detail on how the risk assessment was conducted, including the impact of atypical weather conditions that occur at least as frequently as once in ten years. The utility shall also include all extreme*

weather events of the last 20 years, identified by State declaration of an emergency."

Further instruction was provided by footnote 5: "Atypical weather conditions are weather events that meet the definition of "catastrophic conditions" from the MPSC Service Quality and Reliability Standards less the periods with a State declaration of emergency."

Per the MPSC Service Quality and Reliability Standards, MI Admin Code, R460.702(c):

"*Catastrophic conditions" means either of the following:*

(i) Severe weather conditions that result in sustained service interruptions for 10% or more of an electric utility's or cooperative's customers.

(ii) Events of sufficient magnitude that result in issuance of an official state of emergency declaration by the local, state, or federal government.

Q40. How did PowerGEM's analysis address atypical and extreme weather within the Company's broader risk assessment?

A40. Every year from 2006 to 2025 was searched for a Michigan emergency declaration or documented DTE Electric service interruption event meeting the catastrophic-conditions test. The 44 weather years included in the SERVM analysis, as discussed in Q22 and Q23, were scored via a seven-metric scorecard of load (proxy for temperature, solar, and wind). For each metric, the weather years were assigned a

percentile based on their performance and the most resource-challenged weather years were selected based on a final weighted scoring of 90% or greater. These were then cross-referenced against the 20 years of emergency declaration data. Applying the 90th percentile threshold ensures that extreme weather years are captured in the analysis.

Table 4 identifies the seven metrics, the direction associated with greater modeled risk, and the weight assigned to each metric. The three load metrics collectively account for approximately 50% of the composite score, while the solar and wind metrics each account for 25%, subject to rounding.

Table 4 Extreme Weather Sensitivity Scoring Matrix

Component	Metric	Percentile Direction	Weight
Load	Single highest hour of demand	Higher is worse	0.167
Load	Highest average demand over any one-day period	Higher is worse	0.167
Load	Highest average demand over any three-day period	Higher is worse	0.167
Solar	Largest one-day reduction in solar output relative to normal	Higher is worse	0.125
Solar	Seasonal average solar output	Low is worse	0.125
Wind	Lowest average wind output over a three-day period	Low is worse	0.125
Wind	Seasonal average wind output	Low is worse	0.125

For the summer season, this resulted in the selection of six analysis years: 1994, 2001, 2006, 2011, 2012, and 2018. For the winter season, five years were selected: 1984, 1994, 2014 (Emergency Declaration, polar vortex), 2017, and 2019 (Emergency Declaration, polar vortex). Those selected years were then used to sub-

sample the existing reliability outputs from the model to construct metrics based on those years in isolation.

Q41. Which portfolio and study years did PowerGEM evaluate for the extreme weather sensitivity?

A41. PowerGEM evaluated the revised preliminary PCA in the 2029 and 2033 study years.

Q42. What did the extreme weather sensitivity show?

A42. Table 5 presents the EUE, LOLE, and LOLH results calculated from the selected summer and winter weather-year subsets. These results are conditional on the selected weather years and should be distinguished from the probability-weighted expected-value results calculated using the complete 44 weather year dataset.

Table 5 Extreme Weather Subset Resource Adequacy Results[6]

Study Year	Season	EUE	LOLE	LOLH
2029	Summer	309	0.244	0.633
2029	Winter	0	0	0
2033	Summer	219	0.305	0.538
2033	Winter	0	0	0

Table 6 shows the calculated LOLE of each selected summer weather year.

[6] The results shown are calculated from the selected seasonal weather-year subsets and are not the probability weighted expected value results calculated across the complete 44 weather year dataset.

Line
No.

Table 6 LOLE by Weather Year

Weather Year	2029 Summer LOLE	2033 Summer LOLE
1994	0.017	0.018
2001	0.010	0.008
2006	0.003	0.001
2011	0.032	0.026
2012	0.177	0.247
2018	0.005	0.005

Q43. How should the extreme-weather sensitivity results be interpreted?

A43. The full probability weighted SERVM analysis, which included all 44 historical weather years together with the modeled load-forecast uncertainty and generator performance conditions, showed that the revised preliminary PCA satisfied the 0.10 event-day-per-year LOLE criterion in both study years. The extreme-weather sensitivity separately isolated the model outputs associated with the selected higher-risk summer and winter weather years. The subset results show that the modeled extreme-weather resource adequacy risk was concentrated in the selected summer weather years. The selected winter weather-year subsets produced no EUE, LOLE, or LOLH in either study year. Within the selected summer subset, weather year 2012 accounted for most of the reported LOLE in both 2029 and 2033. These subset results identify the weather conditions contributing most significantly to modeled resource adequacy risk, but they do not replace the probability-weighted results of the full SERVM analysis.

Q44. How did the Company use the resource adequacy results in developing its final PCA?

A44. My analysis was limited to evaluating the resource adequacy of the selected portfolios provided by the Company. Witness Manning explains how the Company considered the resource adequacy results together with its other risks including environmental justice, financial, and grid reliability evaluations, before confirming its final PCA.

Q45. Does this complete your direct testimony?

A45. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

FRANK J. SIRWAITIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF FRANK J. SIRWAITIS

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Frank J. Sirwaitis (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or the Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q3. What is your educational background?

A3. I graduated from the University of Michigan – Dearborn in 2016 with a Bachelor of Arts in Economics, with a focus in Econometrics.

Q4. What is your professional experience?

A4. After graduating from the University of Michigan, I began my professional career with DTE Electric in January 2017 in the Corporate Energy Forecasting department as an analyst with increasing levels of responsibility. In my time with Corporate Energy Forecasting I have worked on long-term sales forecasting (one year or greater), short-term sales forecasting (monthly and daily), peak demand forecasting, economic forecasting, customer forecasting, and weather-normalization of sales and peak. I have also led the development of long-term circuit and substation load forecasting that supports the Company's distribution operations. Additionally, I have led the development of several initiatives to integrate Advanced Metering Infrastructure (AMI) data into various forecasting processes. In 2025 I was promoted to Supervisor of Energy Forecasting.

Q5. What are your current duties and responsibilities?

A5. As a Supervisor of Energy Forecasting I oversee the development of DTE Electric's long-term forecasts, including sales, customers, and peak demand. In addition to leading core forecasting activities, I support the creation of the Company's distribution circuit load forecast, as well as forecasts for distributed generation (DG) and electric vehicles (EVs).

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. Yes. I have completed various workshops hosted by Itron including Energy Forecasting 101, Forecasting and Statistically Adjusted End-Use (SAE) Modeling, and Advanced Forecasting Topics. I have also earned certifications from SAS related to electric load forecasting and programming. I am a member of Itron's Energy Forecasting Group (EFG), as well as the Electric Utility Forecasting Forum (EUFF) group.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in the following cases:

U-20876	2022/2023 EWR Plan
U-21050	2022 PSCR Plan
U-21259	2023 PSCR Plan
U-21322	2024/2025 EWR Plan
U-21425	2024 PSCR Plan
U-21594	2025 PSCR Plan

U-21681	2026-2029 EWR Plan
U-21875	2026 PSCR Plan

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to

1. Present the Company's electric sales, peak demand, system output and customer count forecast for the period 2026-2046 including the base forecast along with supporting scenarios and sensitivities in accordance with the revised Michigan Integrated Resource Planning Parameters (MIRPP) adopted by the Commission's December 18, 2025 order in Case Nos. U-21570 and U-21867.
2. Describe the key forecast drivers and modeling methodologies, including historical sales and peak trends, as well as sources of uncertainty and risk.
3. Detail how building electrification, EVs, energy waste reduction (EWR), and distributed energy resources (DERs) like Distributed Generation (DG) (customer-sited resources including solar photovoltaics (PV) and battery energy storage systems (BESS)) are incorporated into the forecast.
4. Present the treatment of large loads, including baseline inclusions and various scenarios that were assessed as a part of the Company's 2026 Integrated Resource Plan (IRP).
5. Describe the load forecasting alignment between the Company's IRP and Distribution System Plan (DSP).

Q9. Are you sponsoring any exhibits?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-7	Annual Sales by Major Customer Classes, Peak Demand, System Output and Loss Factors 2021-2025 Historical
A-7.1	Annual Sales by Major Customer Classes 2021-2025 Historical Weather Normalized
A-7.2	Base Case Annual Sales by Major Customer Classes, Peak Demand, System Output and Loss Factors 2026-2046 Forecast
A-7.3	Annual Bundled System Output for all Sensitivity Load Forecasts 2026-2046 Forecast
A-7.4	Annual Bundled Peak Demand for all Sensitivity Load Forecasts 2026-2046 Forecast

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. What electric load forecast scenarios, sensitivities, and special-study forecasts did you develop and provide for use in the IRP?

A11. As described by Witness Manning and further explained later in my testimony, I provided the following load forecasts, consistent with the Michigan Integrated Resource Planning Parameters (MIRPP) requirements for use in the IRP process:

1. MIRPP Scenario 1 including the following sensitivities:
    a. With 10% DG
    b. With 15% DG

Line No.

c. With 20% DG

d. With Low Large Load Growth

e. With Medium Large Load Growth

f. With High Large Load Growth

g. With Atypical Weather

2. MIRPP Scenario 2 including the following sensitivities:

a. With Low Large Load Growth

b. With Medium Large Load Growth

c. With High Large Load Growth

d. With Atypical Weather

e. High Load Growth

f. Low Load Growth

g. Alternative Electric Choice Sensitivity

In addition, consistent with the Commission's Orders in Case Nos. U-21990 and U-22058, I developed two forecasts for use in special studies supporting the IRP. These forecasts include:

1. A Base Case excluding load associated with Oracle America Cloud Services LLC ("OACS") and Google LLC ("Google"); and
2. A Base Case that includes OACS load but excludes Google.

Q12. As it pertains to the load forecast, what forecast was used as the Base Case?

A12. The MIRPP Scenario 2 load forecast was used as the Base Case load forecast. This forecast is consistent with the Company's internal planning views and incorporates moderate, baseline, or reference assumptions of the forecast variables discussed

later in my testimony. Accordingly, it represents the Company's most probable outlook for future energy and demand under current policy and market conditions. This Base Case load forecast was used in the MIRPP Scenario 2 as well as in the DTE Reference Case described by Witness Manning.

Q13. How is your testimony organized?

A13. My testimony consists of the following eight parts:

Part I	Key Variables Used to Develop the Forecast
Part II	Forecast Methodology
Part III	Forecast Uncertainty and Risk
Part IV	Historical and Forecast Electric Sales and Peak Demand
Part V	Large Load Analysis and Projections
Part VI	Electric Load Forecast Scenarios and Sensitivities
Part VII	IRP and DSP Forecast Alignment
Part VIII	DG, EVs, Building Electrification, and EWR

PART I: KEY VARIABLES USED TO DEVELOP THE FORECAST

Q14. What are the key variables that affect electricity sales, peak demand and customer forecasts?

A14. The electricity sales, peak demand, and customer forecasts for each customer class (residential, small commercial & industrial (C&I), large commercial & industrial, and streetlighting) are influenced by a wide range of variables, which are discussed in greater detail throughout my testimony.

Key forecast variables include:

- National, state, and local economic projections provided by sources including, but not limited to: S&P Global (formerly IHS Markit) and Moody's Analytics
- Historical weather data from the Detroit Metropolitan Airport (DTW), with normal weather assumptions in the forecast horizon
- The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2025 end-use intensity and end-use saturation estimates for the East North Central Census Division (modified for DTE Electric's end-use information)
- DTE Electric's EWR targets
- DTE Electric's behind-the-meter DG projections for DTE Electric's service territory
- DTE Electric's EV forecast for light-duty and fleet vehicles
- Large load adjustments to account for load changes not otherwise captured in the historical data or economic projections

Q15. How are the key variables utilized to develop forecasts?

A15. As discussed in more detail in Part II, most customer class sales, peak demand, and customer forecasts are derived from linear regression models that relate electricity usage or customer growth to the forecast variables described above.

Q16. As it relates to the key drivers of economic projections, how do you describe the current business climate within DTE Electric's service territory?

A16. Automotive production remains the key driver of Southeast Michigan's economy. Not only is the region home to several automotive assembly plants, but it also

Line No.

harbors a rich network of industry suppliers, contractors, and consultants. Research and development facilities similarly cluster in the area. Numerous local businesses, though not participating directly in the automotive supply chain, serve thousands who make their living in the industry.

The forecast incorporates a near-term increase in automotive production, though EV production adjustments and other economic constraints limit growth from achieving its potential.

Research and development facilities are attracted to the area by talent from local universities and are expanding beyond automotive research into software, medical, and advanced engineering fields.

Southeast Michigan, like much of the country, is experiencing a demographic shift towards an older population on average. This is driving investment and employment in the healthcare sector.

While traditional economic indicators such as automotive production, employment, population, and industrial activity remain foundational inputs to the Company's forecast, the current business environment is also characterized by growing interest from large load customers. As discussed further in Part V of my testimony, these projects can represent additions to electric demand that are not fully reflected in traditional economic forecasts and therefore require additional evaluation within the Company's forecasting and planning processes.

Q17. What is the outlook for Southeast Michigan's economy over the time horizon of the study period, 2026-2046?

A17. Because forecast uncertainty increases in the outer years, I discuss the economic outlook separately for 2026, the medium term (2027 to 2031), and the long term (2032-2046).

Medium-term changes are represented by the compound annual growth rate (CAGR) from base year 2026 through 2031, and long-term changes by the CAGR from 2031 through 2046.

Relative to 2025 levels, in 2026 total nonfarm employment decreases by 0.1%, natural resources and mining employment increases by 0.9%, manufacturing employment falls by 2.8%, total private non-manufacturing employment increases by 0.3%, government employment declines by 0.1%, and automotive production increases by 1.0%, while population decreases by 0.1%.

Over the medium-term, total nonfarm employment is expected to be flat, natural resources and mining employment increases by 0.3%, manufacturing employment declines by 0.9%, total private non-manufacturing employment rises by 0.2%, government employment is expected to be flat, automotive production increases by 5.6% driven by the planned reopening of an automotive manufacturing plant, and population falls by 0.2%.

In the long-term, total nonfarm employment declines by 0.1%, natural resources and mining employment falls by 0.3%, manufacturing employment declines by

0.8%, total private non-manufacturing employment falls 0.1%, government employment declines by 0.2%, automotive production rises by 0.3%, and population declines by 0.4%.

Q18. How do these economic conditions influence electricity usage within DTE Electric's service territory?

A18. Economic and demographic conditions remain important drivers of electricity sales within DTE Electric's service territory; however, customer electricity consumption is increasingly influenced by additional factors that have altered historical usage patterns. Changes in equipment and appliance efficiency, distributed generation, electrification, and the adoption of new end uses all affect how customers use electricity. As a result, the Company's forecast incorporates both traditional economic drivers and these emerging factors to provide a comprehensive assessment of future electricity demand.

Electric sales within each customer class exhibit strong historical relationships to key economic and demographic variables. For example, residential class sales are closely tied to the number of households within the Company's service territory, as seen in Figure 1. Commercial sales closely align with Non-Manufacturing Employment in Figure 2. As commercial activity expands, businesses typically require more employees and greater electricity consumption to support their operations. Similarly, Figure 3 demonstrates the strong relationship between Detroit-area light vehicle production and Industrial sales, reflecting the significant role that automotive manufacturing plays in driving industrial electricity demand.

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Figure 1 Service Area Residential Actual Sales (GWh) and Households (000s)

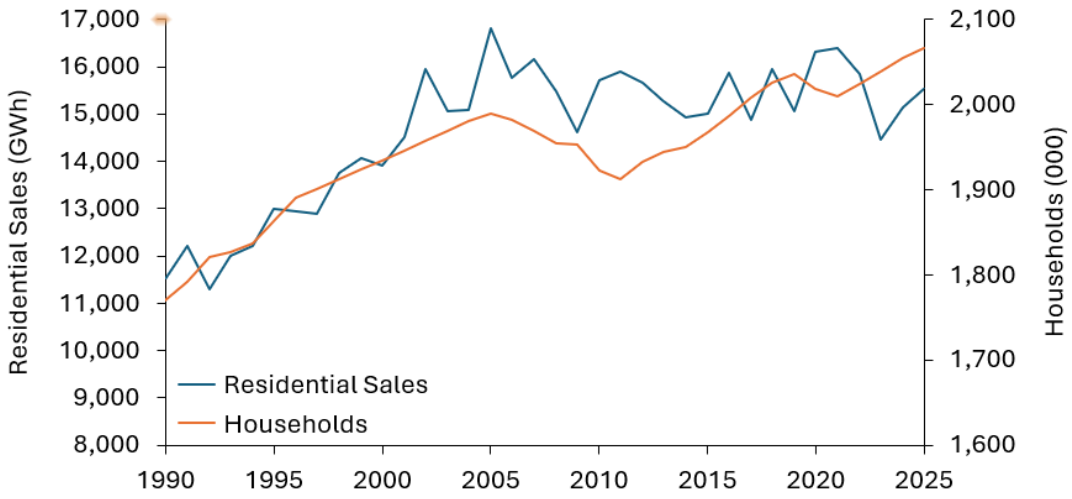
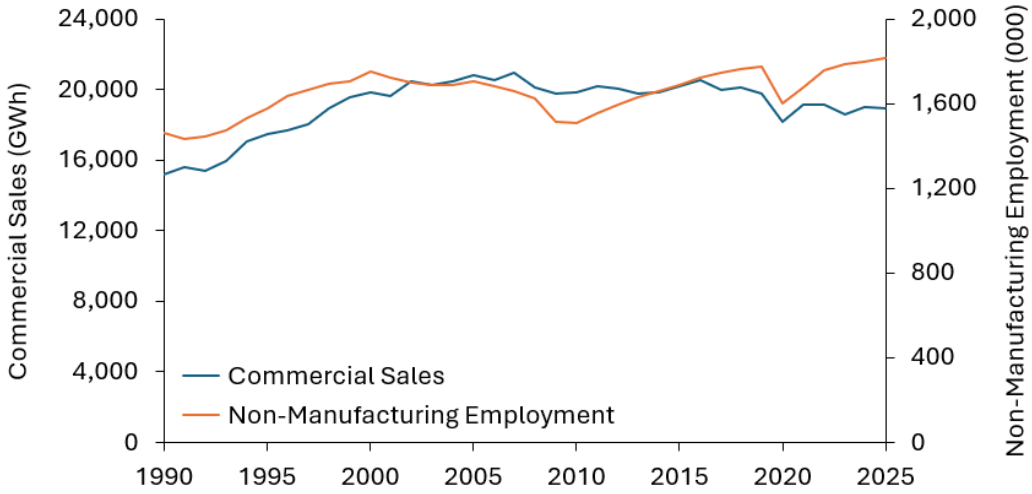
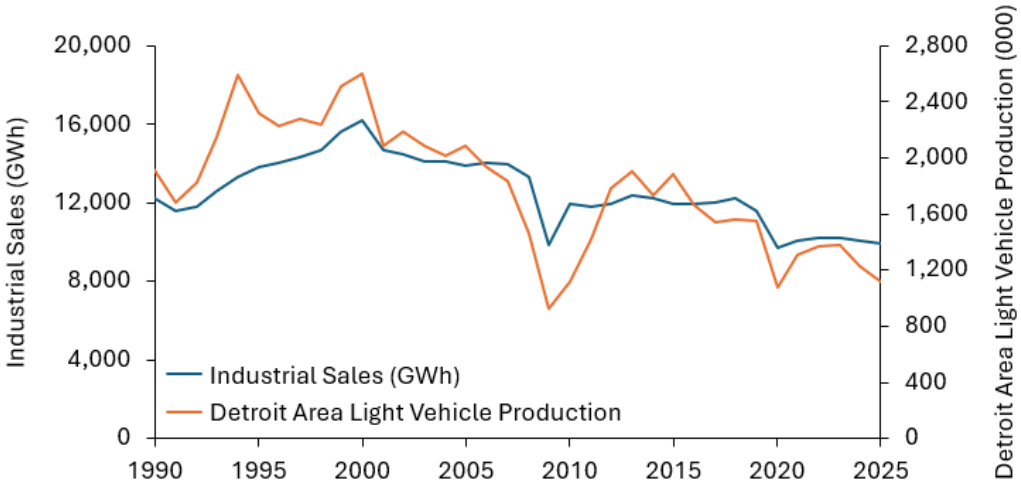


Figure 2 Commercial Actual Sales (GWh) and Non-Manufacturing Employment (000s)



Line No.

Figure 3 Service Area Industrial Actual Sales (GWh) and Detroit-Area Light Vehicle Production (000s)



Figures 1 through 3 show that economic activity remains a foundational driver of electricity usage, although efficiency, distributed generation, and electrification are playing an increasingly important role in shaping customer demand.

Q19. How is weather applied in the forecast?

A19. Weather is one of the primary variables used in each customer class forecast model. In each model, actual weather, measured in the form of heating degree days (HDDs) and cooling degree days (CDDs) is used to capture the unique relationship between a customer class's energy consumption and weather conditions. HDDs are calculated by subtracting average daily temperature from a defined temperature base, such as 65°F. Conversely, CDDs are calculated by subtracting the same temperature base from average daily temperature.

In regression modeling, a coefficient is measured to quantify this weather-energy relationship. Once calculated, the coefficient is applied to the weather assumptions used in the forecast horizon. For the forecast horizon, normal weather is assumed, as it represents the most prudent basis for long-range weather expectations.

Q20. Can you describe the HDD and CDD bases used in the forecast?

A20. Yes. As illustrated in Figures 4 and 5, weather response varies by customer class. Residential sales are more sensitive to weather and typically begin cooling building stock at an average temperature of 60°F. Small C&I sales are less responsive to weather and typically begin cooling building stock at an average of 50°F. These weather relationships are also non-linear in nature, necessitating the use of multiple HDD and CDD bases to capture weather response by customer class.

The HDD and CDD bases, represented by the name and temperature of the base, used for each customer class are as follows:

- Residential: HDD25, HDD60, CDD60, CDD65, CDD70 and CDD75
- Small C&I: HDD50, CDD50, CDD60, and CDD70
- Large C&I (varies by supersector):
    - Education and Health: CDD50
    - Transportation, Trade and Utilities (TTU): HDD50 and CDD50
    - Offices: HDD45 and CDD55
    - Other Markets: HDD45 and CDD55
    - Automotive: HDD50 and CDD60
    - Other Manufacturing: CDD55

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Figure 4 Residential Daily kWh Per Customer vs Temperature (°F)

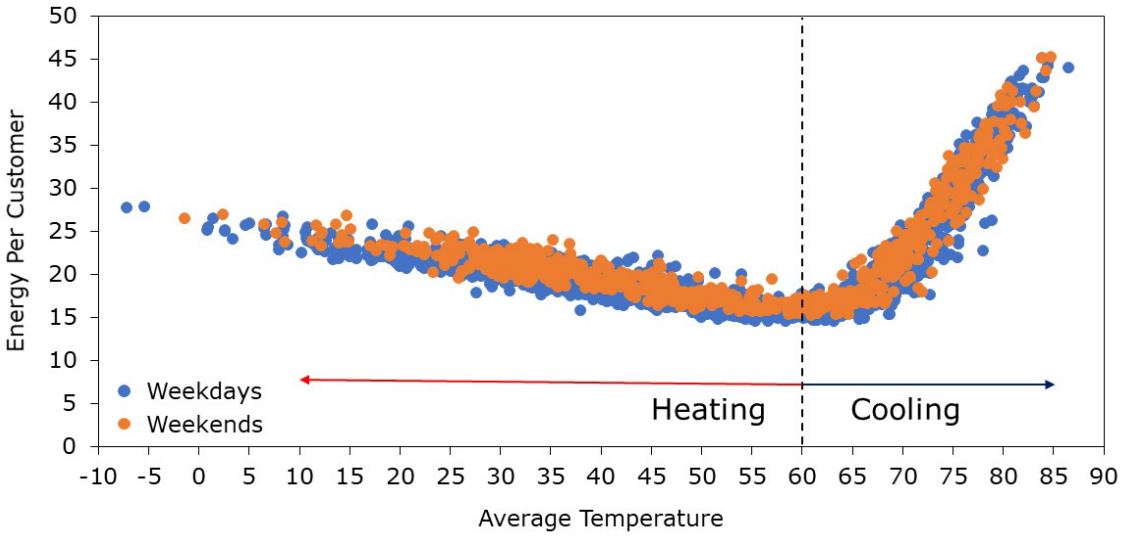
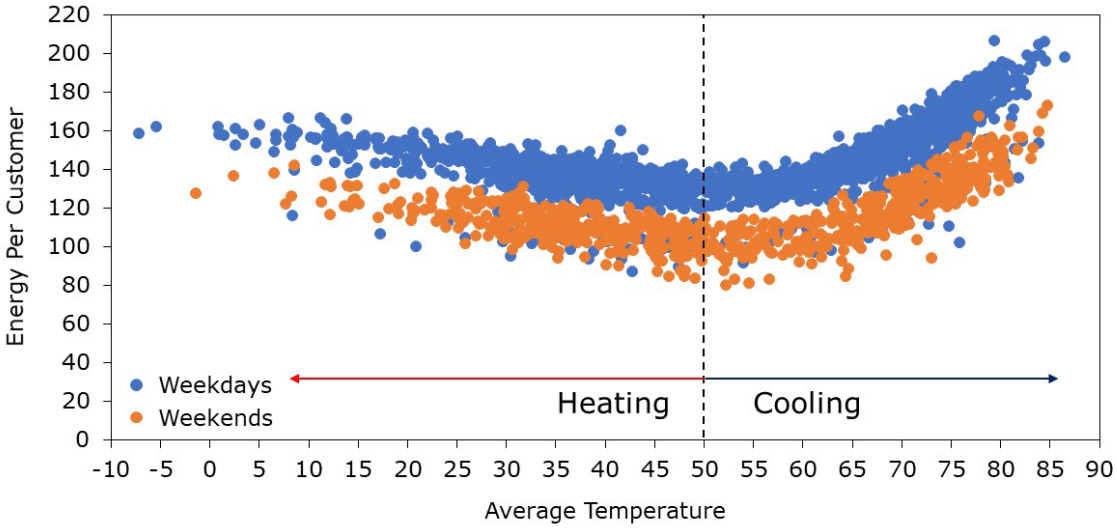


Figure 5 Small C&I Daily kWh-Per-Customer vs Temperature (°F)



Q21. How does DTE Electric define normal weather?

A21. DTE Electric defines normal weather as a 15-year average of historical values, updated annually as recommended by the Commission in Case No. U-20471. In this case, the normal weather period spans 2010-2024. Historical actual sales presented in my exhibits have also been weather-normalized using the same normal

weather assumptions applied in the forecast, allowing for consistent comparison purposes.

To derive normal weather values, daily average temperatures are converted to HDDs and CDDs for various bases and then averaged across years. This process yields normal HDD and CDD values for each base across a given day, month, and year.

Q22. What temperature assumptions were made regarding the peak demand forecast?

A22. The normal temperature on the day of the annual peak is assumed to be 82.5F, representing the mean peak-day temperature recorded at DTW. This value is derived from the average peak-day mean temperature over the same 15-year normal weather period of 2010-2024, consistent with the methodology described above. The mean temperature is calculated as the average of 24-hourly temperatures observed throughout the day. The annual peak day is assumed to occur on a weekday in the month of July.

PART II: FORECAST METHODOLOGY

Q23. What is the general approach used in developing the forecast for DTE Electric's service area electric sales and system output?

A23. The general approach reflects widely accepted industry standards for electricity forecasting, primarily regression analysis and statistically adjusted end-use (SAE) modeling. These methods have consistently produced reliable forecasts for DTE

Electric service area electric sales with historically, on average, small variances from actual annual sales.

Forecasts are developed separately for each major rate classification: Residential, Commercial and Industrial (C&I), Large Loads, and Streetlighting. The residential and small C&I sales forecasts are derived by combining a use-per-customer forecast, using a SAE specification, with a customer forecast. The large C&I forecast is derived through a generalized econometric model separated into seven unique supersectors. Large Loads are forecast outside the econometric models using customer-specific plans and projections. Streetlighting is forecast based on customer growth, and adoption of higher efficiency lighting technologies. The net system output is forecasted as the sum of the electric sales values and the projected losses.

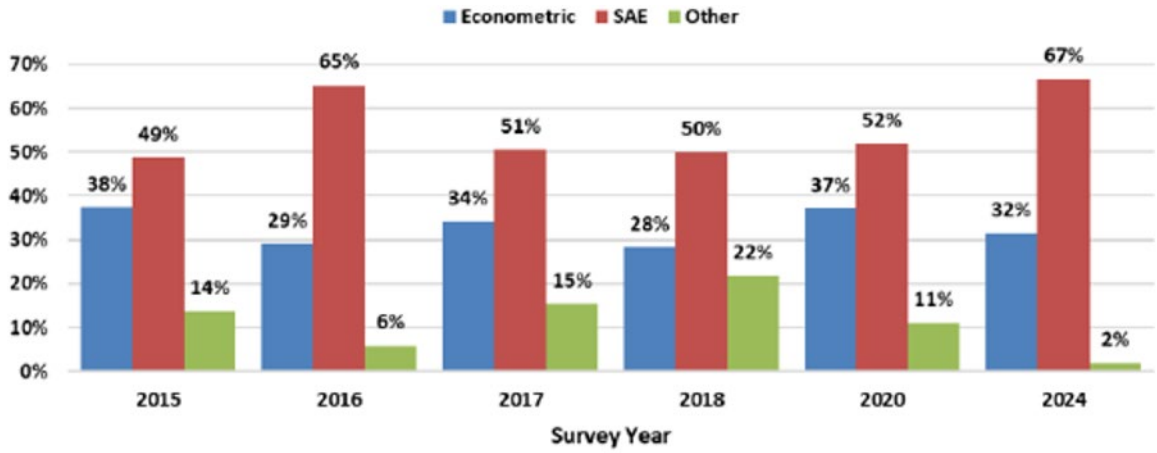
Q24. Why is regression modeling the primary method the Company uses to forecast?

A24. Regression modeling (including both standard econometric and SAE) is the preferred approach not only from the Company but also from peer utilities (98% of utilities as of 2024) as seen in Figure 6. The Company has been using regression modeling to forecast sales since 2003[1].

[1] https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000000vMiiAAE

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Figure 6 Itron Forecasting Benchmark Survey for Residential Model



Regression modeling offers quantitative insights into the relationships between variables, crucial for understanding and reflecting long-term trends. For instance, it can quantify the impact of weather variations, economic conditions, and changes in appliance adoption on electricity consumption. Properly specified and validated regression models provide accurate and reliable forecasts. Their flexibility to incorporate multiple predictors helps capture the complexity of real-world variations in electricity usage.

Q25. What standards are used to evaluate the results of the regression models?

A25. A variety of statistical tests and metrics are used to evaluate the effectiveness of a regression model. These include, but are not limited to:

- Adjusted R-squared measures how well the model explains variation in historical data while accounting for the number of explanatory variables included. Higher adjusted R-squared values increase confidence in the model's ability to explain historical relationships and provide reliable

forecasts. Consistent with accepted statistical practice for forecasting, the Company generally seeks adjusted R-squared values of approximately 0.90 or higher, indicating that roughly 90% of the observed variation in electricity usage is explained by the model.

- Mean Absolute Percentage Error (MAPE) measures forecast accuracy by quantifying the average percentage difference between actual and predicted values. The Company evaluates both in-sample and out-of-sample MAPE results when assessing model performance. Consistent with standard forecasting practices, MAPE values of approximately 3% or less are indicative of strong model performance.
- The Durbin-Watson (DW) statistic is used to detect autocorrelation in regression residuals. Significant departures from a DW value of 2 may indicate the presence of systematic over- or under-forecasting patterns. Consistent with accepted statistical practice, the Company generally seeks DW statistics between 1.5 and 2.5.
- T-statistics evaluate the statistical significance of individual explanatory variables and help determine the extent to which each variable contributes to explaining changes in the dependent variable. Consistent with standard statistical practice, absolute t-statistics greater than approximately 2.0 are often considered evidence of statistical significance.
- P-values assess whether the relationship between an explanatory variable and the dependent variable is likely to be genuine or could have occurred by chance. Consistent with broadly accepted statistical standards, p-values below 0.05 are commonly used as evidence that a variable is statistically significant.

While the Company strives to satisfy each of these evaluation criteria, model selection is based on the totality of the evidence. In certain circumstances, deviations from one metric may be acceptable when justified by overall model performance, economic reasonableness, forecast stability, and consistency with accepted forecasting practices.

Q26. Can you describe the data used to construct the forecast models?

A26. Yes. The forecast and customer models were estimated with monthly historical consumption data beginning in January 2015, with estimation ending in August 2025. The forecast for both sales and customers was extended through 2046 and was used to develop the long-term system energy and peak demand forecast.

Q27. How were the SAE models developed?

A27. The SAE models begin as a standard end-use representation of energy consumption expressed as the sum of individual end-uses. Each end-use is comprised of a saturation projection, representing how many customers have each appliance or piece of equipment along with an estimate of average kWh usage. The combination of saturations and average electricity per end-use are indexed and calibrated to the Company's base-year use-per-customer to create an initial consumption forecast for each end-use. Once the end-use intensities are developed, representing the baseline amount each end-use consumes, they are combined with utilization variables. These variables reflect how conditions such as weather, economics and efficiency influence the level of use between different months and over time. The utilization variables then form three aggregated explanatory variables:

- XHeat – An aggregated heating variable that captures changes in heating end-use saturation and efficiency, combined with economic and other factors that impact the utilization of heating equipment such as HDDs
- XCool – An aggregated cooling variable that captures changes in cooling end-use saturation and efficiency, combined with economic and other factors that impact the utilization of cooling equipment such as CDDs
- XOther – An aggregated base-load variable that captures changes in base-load end-use saturation and efficiency, combined with economic and other factors that impact the utilization of base-load equipment such as number of days in each month

These variables, along with seasonal factors, are then regressed against the Company's historical monthly use per customer sales. The model effectively acts as the statistical adjustment and calibrates the end-use forecast to the Company's historical sales. The resulting use-per-customer forecast is then multiplied by a customer count forecast to generate the total sales for the class.

Q28. How do the residential and small C&I SAE models differ?

A28. While both classes utilize the same SAE modeling framework, the residential and small C&I models differ in the number of end-uses included, the data sourced to construct the end-use intensities, and the economic variables that drive utilization.

For the residential class, the model includes 22 end-uses. Appliance saturations and average use per end-use are based on DTE Electric's residential appliance saturation survey and the EIA's AEO 2025 data for the East North Central Region.

Utilization is driven primarily by weather, real personal income, population, and number of residential households. Residential customer counts are forecast using household projections for Southeast Michigan and total residential sales are calculated by multiplying the customer forecast by the SAE derived use per customer.

For the small C&I class, the model includes 11 end-uses. Saturations and average electricity usage per end-use are derived from the EIA's AEO 2025 data for the East North Central Region. The projections are weighted by the intensity and prevalence of 11 different EIA defined building types to reflect the diversity of small C&I facilities. To further align the model with the Company's service area, end-use intensities are weighted using DTE Electric specific building energy consumption. For small C&I, the primary variables used to explain utilization are weather, gross state product, non-manufacturing employment, and residential households. Small C&I customers are modeled using a regression with residential households as the primary variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total small C&I class sales forecast.

Q29. How was the large C&I Forecast developed?

A29. The large C&I forecast was developed using an econometric approach tailored to seven distinct supersector markets. The forecast begins by disaggregating total large C&I sales into detailed market segments based on each customer's North American Industry Classification System (NAICS) code that are subsequently grouped into supersectors defined by the Bureau of Labor Statistics. The seven

supersectors include medical and education, transportation trade and utilities (TTU), offices, other markets, automotive, other manufacturing, and steel.

For each supersector, an econometric regression model is developed using explanatory variables such as corresponding supersector employment and gross state product, automotive production, weather, and cumulative EWR savings to drive the forecast. The regression results are evaluated for validity and reasonableness through various model statistics.

Because the large C&I class is not modeled using an end-use model, regression modeling alone does not capture incremental load growth from emerging technologies or customer specific changes. Therefore, two post regression adjustments were applied:

1. Fleet and public charging electrification growth to account for expected increases in electric vehicles.
2. Large customer projects including expansions or closures informed by the Company's customer account managers.

Q30. Are large loads included in the large C&I model?

A30. No, as described in further detail in Part V of my testimony, the Company distinguishes Large Loads from traditional large C&I customers based on magnitude of demand. While both customer types may take service under Rate Schedule D11, the average large C&I customer has a peak demand of approximately 1 MW, whereas a Large Load can exceed 100 MW at a single site.

As a result, Large Loads are evaluated separately within the Company's load forecasting and planning processes.

Q31. How was the Customer Choice sales forecast developed?

A31. The Customer Choice sales forecast was based on 10% of retail sales utilizing historical class ratios applied to the Choice cap. Because the Choice cap is based on total retail sales, continued load growth associated with electric vehicle adoption and anticipated large load customer growth is expected to increase the amount of load eligible to participate in the Customer Choice program over the planning horizon. This would create additional Customer Choice capacity beyond levels experienced in recent history. In the Company's Base load forecast, Customer Choice participation was assumed to remain at the statutory cap and fully utilize additional available Choice program capacity as retail sales growth increases the amount of load eligible to participate in the program. As discussed by Witness Hajj, the Company's Base Case assumes this expanded capacity remains fully subscribed, however, future enrollment levels remain uncertain. To evaluate this uncertainty, the Company has developed a sensitivity for Alternative Electric Choice sales which is further explained in Part VI of my testimony.

Q32. How was the DTE Electric system peak demand forecast developed?

A32. A bottom-up hourly load model was used to forecast annual DTE Electric service area and DTE Electric bundled peak demand. This model was also utilized to determine monthly peak demands in the forecast period.

Line No.

Q33. What is a bottom-up hourly load model?

A33. A bottom-up hourly load model obtains the peak demand forecast by summing hourly values from all the different end-uses. Load profiles are developed for each of the sales classes utilizing the Company's historical hourly AMI data. Residential and small C&I classes were further broken into base, cooling, and heating end-uses which captures changing peak demand levels based on the composition of the underlying load shapes, and changes in end-use consumption. Additional load profiles for technologies, such as various EV charging behaviors and DG, are also used.

The load profiles are scaled to the monthly energy forecasts by customer class, adjusted for losses, and summed up to predict the system total. The highest hourly value in a year or month is the peak forecast.

Q34. What are the losses assumed in the forecast?

A34. Based on the 2021 Line Loss Study conducted by Burns & McDonell, the Company applies a loss factor specific to each customer class to gross-up forecasted electric sales. This adjustment reflects the energy needed to overcome system losses and yields the total output requirement shown in Exhibit A-7.

Q35. What are the advantages of using a bottom-up hourly load model to forecast system peak demand?

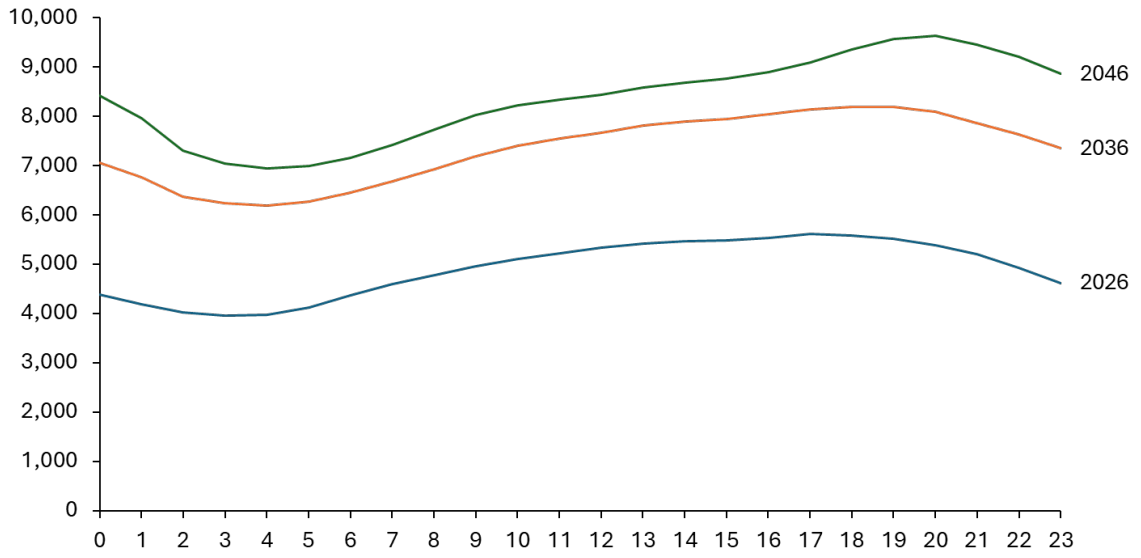
A35. Modeling system peak demand using a bottom-up hourly load modeling approach offers significant advantages because it captures load shape diversity across customer classes and technologies. As customers adopt more efficient HVAC

equipment or as technologies such as EVs increase in penetration, a bottom-up approach enables a more accurate assessment of how both the magnitude and timing of system peak demand may evolve.

Within an IRP, this approach is particularly valuable because generation resources must be sufficient to meet demand during all hours of the day and throughout the year. Bottom-up hourly modeling supports the scenario analysis performed to evaluate a range of potential future outcomes associated with different technology adoption pathways that could materially reshape customer demand. For example, EVs and DG may not align with the Company's current system peak, therefore, understanding how increasing adoption levels could shift the peak hour and overall load profile is critical for effective long-term planning. Figure 7 illustrates these dynamics by showing the difference in average load profiles over time under Scenario 1. As illustrated in the graph, average hourly bundled load increases across all hours by 2036, reflecting the impact of emerging large load growth. By 2046, continued EV adoption drives a shift in the daily load profile, with peak demand occurring later in the evening and disproportionately higher growth in the late evening and early morning hours.

Line No.

Figure 7 Scenario 1 Average Hourly Bundled Load (MW)



Q36. How do the weather assumptions in the bottom-up hourly load model align with the normal weather assumptions described earlier in your testimony?

A36. The hourly load model utilizes a consistent 15-year historical period to develop HVAC profiles. To ensure alignment across the HDD and CDD assumptions used in long-term energy forecasting for generation and distribution planning, the Company constructed a representative typical weather pattern.

This typical weather pattern was developed using a combination of rank-and-average and rank-and-median methodologies. The process consists of the following steps:

1. A 15-year historical dataset of hourly weather observations is compiled, including temperature, humidity, wind speed, and global horizontal irradiance, consistent with the normal weather period.

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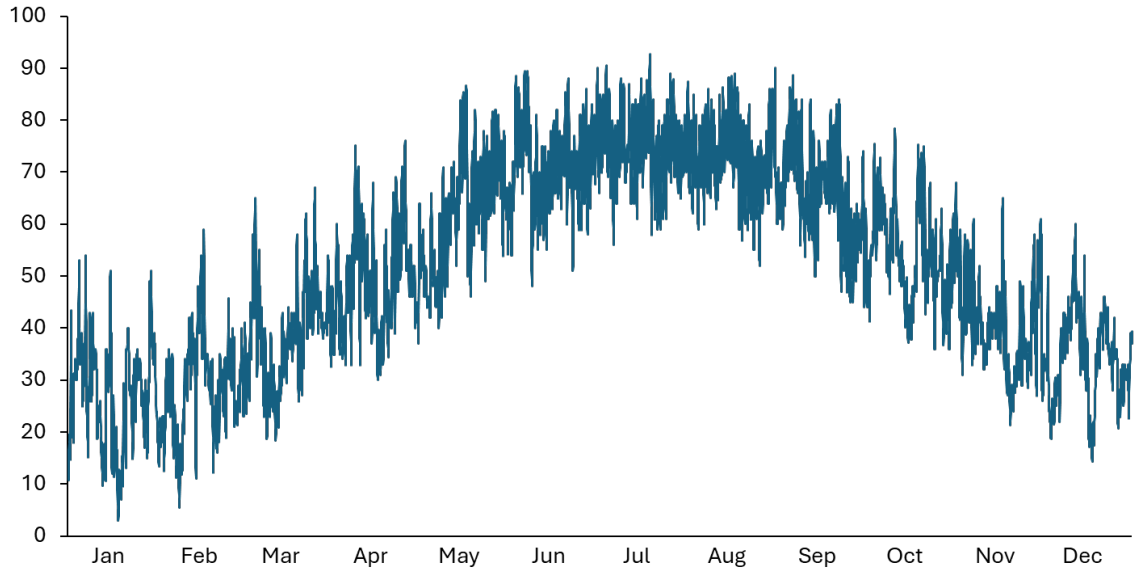
2. For each month, historical days are ranked by daily average temperature. Median conditions are then identified for each rank to represent typical weather conditions across the full range of observed outcomes.
3. The resulting median weather days are reordered using an "order" variable derived from a representative historical year to ensure realistic seasonal progression and appropriate placement of peak-producing conditions.
4. The reordered weather profiles are mapped onto forecast calendars such that day-of-week alignment, monthly totals, and peak timing are preserved, ensuring consistency and stability across forecast years.
5. The weather pattern is adjusted so that monthly totals for key variables (e.g., solar irradiance, wind speed, and humidity) align with normal conditions while maintaining smooth day-to-day transitions.

To further enhance stability across forecast vintages, a rank-and-average approach (using the mean rather than the median) is applied to the five warmest days in summer-peaking months and the five coldest days in winter-peaking months.

The resulting typical weather pattern captures the appropriate level of weather variability experienced in a typical year, including severe, moderate, and mild conditions across hours, days, and months. Figure 8 illustrates the hourly typical weather pattern for an example year used in the forecast.

Line No.

Figure 8 Hourly Typical Weather Pattern (Temperature °F)



PART III: UNCERTAINTY AND RISK

Q37. What are the principal sources of uncertainty in the forecast?

A37. The Company's load forecast is subject to uncertainty because the future values of several important forecast drivers may differ from the assumptions reflected in the Base Case load forecast. Principal sources of uncertainty include the pace of EV adoption, the number, size and timing of new large load customers, the level of participation in the Customer Choice market, building electrification, customer-sited DG, and changes in customer growth and economic activity.

EV-related forecast uncertainty is driven predominantly by uncertainty in the rate of customer uptake, or EV penetration, in the Company's service area. Factors such as vehicle costs, charging infrastructure availability, federal and state policies and incentives, technological developments, and customer charging behavior may

affect the timing and magnitude of EV-related energy and peak-demand load growth.

Large loads are also an important source of uncertainty. Prospective large load projects may differ from forecast assumptions regarding whether and when they proceed, their ultimate load requirements, the timing and duration of their load ramps, and their long-term utilization. Because individual large load projects may have substantial load requirements, changes in these assumptions can materially affect projected energy requirements and peak demand.

Additionally, as discussed by Witness Hajj, the Customer Choice market represents an emerging source of uncertainty. Large load growth is expected to substantially increase the amount of load eligible to take service under the Customer Choice program, increasing uncertainty regarding future utilization of the available capacity under the Choice cap. Future enrollment levels may differ from the Base assumption that available Customer Choice program capacity will be fully utilized. The Company therefore developed an Alternative Electric Choice forecast sensitivity that does not assume full utilization of available Customer Choice capacity, as discussed in Part VI of my testimony.

Building electrification and customer-sited DG also contribute to forecast uncertainty. The future adoption of building electrification, including electric space heating, water heating, and other end uses, depends on evolving building codes, customer preferences, technology costs, and government policies and incentives.

DG, particularly customer-sited solar, introduces uncertainty through variability in adoption rates, system sizing, and operational behavior.

Customer growth and economic activity provide additional sources of uncertainty through changes in population, employment, and economic mix.

Q38. How did the Company account for these sources of uncertainty in the forecasts provided for in the IRP?

A38. The Company developed alternative load forecasts that vary assumptions regarding important sources of forecast uncertainty. These forecasts include low, medium, and high large load growth; high and low overall load growth; alternative levels of DG adoption; atypical weather; and an alternative level of Customer Choice participation. Collectively, these alternative forecasts permit the Company to evaluate a range of potential future load requirements rather than relying exclusively on a single forecast outcome.

I discuss the assumptions and development of these alternative load forecasts in Part VI of my testimony. Witness Manning explains how the alternative forecasts were incorporated into the Company's resource planning models and evaluated through the applicable IRP scenarios and sensitivities.

Q39. What planning risks may arise if actual load differs materially from the forecast?

A39. If actual load grows more rapidly than forecast, generation, capacity, transmission, or distribution infrastructure may be needed earlier than anticipated. This may

create risks related to reliability, resource adequacy, cost, and the timely development of resources and infrastructure needed to serve customers. Conversely, if load growth occurs more slowly than forecast, resources or infrastructure developed based on the higher forecast may be needed later than anticipated or may be underutilized. This may result in customers bearing costs for resources or infrastructure before those investments are fully needed.

These risks demonstrate why the IRP evaluates multiple load forecasts reflecting different assumptions regarding future load growth. Witness Manning explains how these load forecasts were evaluated in the IRP modeling, and Witness Hajj discusses how the modeling results informed the Company's broader planning conclusions and Proposed Course of Action (PCA).

PART IV: HISTORICAL AND FORECAST SALES AND PEAK DEMAND

Part IV Section I: Sales

Q40. What has been the compounded annual growth rate (CAGR) of DTE Electric sales over the last five years?

A40. As shown in Exhibit A-7.1, weather normalized service area sales from 2021 to 2025 have declined overall during the five-year historical period. In 2021, total service area sales were 45,607 GWh and 2025 sales were 44,577 GWh, representing a CAGR of -0.6%.

Bundled sales have decreased from 41,263 GWh in 2021 to 40,080 GWh in 2025, representing a CAGR of -0.7%. The customer choice sales increased from 4,344 GWh in 2021 to 4,497 GWh in 2025, a CAGR of 0.9%. Refer to Exhibit A-7.1 for

Line No.

additional detail regarding historical actual sales for the service area, bundled and customer choice.

Q41. What is the CAGR of the DTE Electric service area electric sales in the Base Case over the forecast period?

A41. In the Base Case, service area sales are projected to increase over the forecast period. In 2025, sales were 44,577 GWh and expected to increase to 68,075 GWh in 2046 as shown in Exhibit A-7.2. This represents a 2.0% average annual increase.

Q42. What is the CAGR of DTE Electric bundled electric sales in the Base Case over the forecast period?

A42. In the Base Case, bundled sales are projected to increase over the forecast period. In 2025, sales were 40,080 GWh and expected to increase to 61,307 GWh in 2046 as shown in Exhibit A-7.2. This represents a 2.0% average annual increase.

Q43. What is the CAGR of DTE Customer Choice electric sales in the Base Case over the forecast period?

A43. In the Base Case, customer choice sales are projected to increase over the forecast period. In 2025, sales were 4,497 GWh and expected to increase to 6,768 GWh in 2046 as shown in Exhibit A-7.2. This represents a 2.0% average annual increase.

Q44. What is the outlook for residential class sales in the Base Case?

A44. As shown in Exhibit A-7.2, DTE Electric's residential class sales in the Base Case are projected to increase at an average annual rate of 0.1% from 2025 through 2046. As discussed in Part II and Part VIII of my testimony, long-term residential sales

trends are influenced by several key factors. Growth in residential sales is driven by projected increases in household counts, which contribute to customer growth, as well as continued adoption of EVs and home charging applications. This growth is partially offset by lower usage per customer resulting from energy efficiency improvements driven by national standards and the Company's EWR programs. In addition, increasing adoption of solar PV systems is expected to reduce on-site consumption served by the Company, thereby lowering residential sales.

Q45. What is the outlook for small C&I sales in the Base Case?

A45. As shown in Exhibit A-7.2, DTE Electric's service area small C&I class sales in the Base Case are projected to increase at an average annual rate of 1.8% from 2025 through 2046. As discussed in Part II and Part VIII of my testimony, long-term trends in small C&I sales are influenced by several key factors. Growth in small C&I sales is driven by projected increases in demand associated with public, workplace, and fleet charging applications, as well as increased usage in certain office building-related end-use applications. Customer growth in the class is also generally consistent with trends present in residential customer counts. This growth is partially offset by declines in consumption from other end uses, where increases associated with economic activity are moderated by improvements in equipment efficiency.

Q46. What is the outlook for large C&I in the Base Case?

A46. As shown in Exhibit A-7.2, DTE Electric's service area large C&I class sales in the Base Case are projected to increase at an average annual rate of 0.1% from 2025 through 2046. As discussed in Part II of my testimony, long-term trends in large

C&I sales are influenced by differences across the class's underlying supersector markets. Sales growth in certain markets, including offices, other markets, and automotive, is expected to be supported by projected growth in associated economic activity such as employment levels and automotive production that exceed declines attributable to energy efficiency. This growth is partially offset by declining sales in other markets, including education and health, TTU, other manufacturing, and steel, where projected economic activity is less optimistic and constrained by continued energy efficiency improvements. Table 1 provides a summary of the forecasted sales growth rates by supersector.

Table 1 Supersector Sales 2025-2046 CAGR

Supersector	2025-2046 Sales CAGR
Education & Health	-0.1%
Trade, Transportation & Utilities (TTU)	-0.8%
Offices	0.2%
Other Markets	0.6%
Automotive	0.1%
Other Manufacturing	-0.4%
Steel	-0.3%
Total Large C&I	0.1%

Q47. What is the outlook for large loads in the Base Case?

A47. As discussed in greater detail in Part V of my testimony, the Company anticipates two large load customers in the Base Case. These loads are expected to begin

energizing in 2027, and after the full load is online, are projected to collectively contribute an additional 18,182 GWh of sales beginning in 2029.

Q48. What is the outlook for street lighting sales in the Base Case?

A48. In the Base Case, street lighting sales are projected to decrease 0.3% annually, on average, from 2025 through 2046 due to adoption of more efficient lighting.

Part IV Section II: Peak Demand

Q49. What has been the CAGR of DTE Electric peak demand over the last five years?

A49. As shown in Exhibit A-7.1, the service area peak demand in 2021 was 11,358 MW and 2025 peak demand was 11,017 MW, representing a CAGR of -0.8%. The bundled peak demand was 10,552 MW in 2021 and 10,219 MW in 2025 at a CAGR of -0.8%. Refer to Exhibit A-7.1 for additional details regarding historical actual peak demand for service area, bundled and customer choice.

Q50. What is the CAGR of the DTE Electric service area system peak demand in the Base Case over the forecast period?

A50. As shown in Exhibit A-7.2, DTE Electric's forecast service area peak demand in the Base Case increases from 11,017 MW in 2025 to 13,228 MW in 2046, representing a compound annual growth rate of 0.9%. The increase in peak demand is mainly due to the large load growth.

Q51. What is the CAGR of the DTE Electric bundled peak demand in the Base Case over the forecast period?

A51. As shown in Exhibit A-7.2, DTE Electric's bundled peak demand in the Base Case increases from 10,219 MW in 2025 to 12,169 MW in 2046, representing a compound annual growth rate of 0.8%.

PART V: LARGE LOAD ANALYSIS AND PROJECTIONS

Q52. How were large load additions handled in the load forecast?

A52. As Witness Hajj explains, the Company uses "large load" according to the particular regulatory, forecasting, or modeling context being addressed. Identified large loads were evaluated separately from the economic and demographic trends modeled in the load forecast. This separate treatment reflects that an individual large load project may represent a substantial and concentrated addition to electric demand with a project-specific development schedule, anticipated energization date, load ramp, and operating characteristics that are not captured by broader economic and demographic projections. The resulting forecast combines projected load growth derived from the Company's forecasting models with separately developed large load assumptions to estimate future energy requirements and peak demand.

Q53. Which large loads are reflected in the base load forecast submitted with this IRP, and how were they incorporated?

A53. The base load forecast submitted with this IRP reflects the loads associated with OACS and Google. For purposes of the base load forecast submitted in this proceeding, the Company treated an identified large load as contracted when the

customer had executed the service agreements necessary to support the forecasted load and the available customer-specific information provided a reasonable basis for developing the load projection. OACS and Google satisfied those criteria when the forecast was finalized. This treatment is consistent with the IRP Filing Requirements issued by the Commission in Case Nos. U-21570 and U-21867 on December 18, 2025, which direct utilities to include contracted large loads in the base load forecast, and provides the criteria used by the Company to determine which identified large loads were reflected in this forecast.

The Commission approved the agreements associated with OACS in its December 18, 2025 order in Case No. U-21990. DTE Electric has requested Commission approval of the agreements associated with Google in Case No. U-22058, and that request remains pending.

Separate load projections were developed for OACS and Google using customer-specific information regarding anticipated energization, ramp schedules, and projected full capacity. The OACS load projection assumes an energization date of January 2027 with the projected full capacity of 1,383 MW being achieved by December 2027. The Google load projection assumes an energization date of December 2027 with the projected full capacity of 1,000 MW being achieved by December 2028. The load projections for both large load additions were then added on top of the bottom-up hourly load forecast previously described.

Q54. Did the Company develop alternative forecasts for prospective large load growth?

Line No.

A54. Yes. Consistent with the MIRPP requirements, the Company developed low, medium, and high large load forecasts in addition to the base load forecast. These forecasts reflect different assumed levels and timing of prospective large load growth and were provided as inputs for the corresponding IRP modeling sensitivities. I describe the development of those forecasts in Part VI of my testimony, and Witness Manning describes how they were used in the IRP modeling.

Q55. What forecasts did you develop to support the analyses comparing load impacts with and without the inclusion of OACS and Google?

A55. In addition to the base load forecast, which reflects the loads associated with both OACS and Google, two alternative forecasts were developed. The first alternative forecast excludes the loads associated with both OACS and Google. The second alternative forecast reflects the OACS load but excludes the Google load.

These alternative forecasts provide the load inputs used to evaluate the effects associated with each load. The comparison with and without the OACS load supports compliance with the Commission's December 18, 2025 Order in Case No. U-21990, which directs the Company to compare the resource requirements necessary to serve its load with and without the OACS load.[2] The alternative forecasts also allow the Company to perform a corresponding analysis with and without the Google load. Witnesses Manning and Machi describe how the forecasts were used in the resource planning and rate impact analyses, respectively.

[2] Case No. U-21990, December 18, 2025 Order, pp. 35–36, 44.

Part VI: ELECTRIC LOAD FORECAST SCENARIOS AND SENSITIVITIES

Q56. Did you prepare alternative load forecasts for this proceeding?

A56. Yes. I prepared the MIRPP Scenario 1 and Scenario 2 load forecasts and the alternative load forecasts used as inputs to their corresponding modeling sensitivities. In total, 16 alternative forecasts were prepared, as shown in Exhibits A-7.3 and A-7.4. Witness Manning describes how these forecasts were evaluated in the IRP modeling.

Q57. Can you explain the difference between a load forecast scenario and a sensitivity forecast?

A57. Yes. For purposes of the load forecast, a scenario is an alternative projection that incorporates coordinated changes to multiple forecast assumptions. For example, the load forecast developed for MIRPP Scenario 1 changes assumptions concerning EV adoption, building electrification, and weather relative to the base case load forecast.

A sensitivity forecast generally begins with a specified scenario or the base case load forecast, changes one forecast assumption, and holds the other forecast assumptions constant. This allows the Company to evaluate the effect of the changed assumption on projected energy requirements and peak demand. Witness Manning describes how the resulting forecasts were used as inputs to the corresponding IRP modeling sensitivities.

Q58. What sensitivity forecasts were developed under MIRPP Scenario 1?

A58. I developed the following sensitivity forecasts from the MIRPP Scenario 1 load forecast: 10% DG, 15% DG, 20% DG, Low Large Load Growth, Medium Large Load Growth, High Large Load Growth, and Atypical Weather. The resulting annual bundled system output and peak-demand forecasts are presented in Exhibits A-7.3 and A-7.4.

Q59. What sensitivity forecasts were developed under MIRPP Scenario 2 or the DTE Electric Reference Case?

A59. I developed the following sensitivity forecasts from the MIRPP Scenario 2 load forecast: Low Large Load Growth, Medium Large Load Growth, High Large Load Growth, Atypical Weather, High Load Growth, Low Load Growth, and the Alternative Electric Choice Sensitivity. As discussed earlier in my testimony, the MIRPP Scenario 2 load forecast also serves as the base case load forecast used in the DTE Electric Reference Case. Witness Manning identifies which sensitivity forecasts were evaluated with each modeling case.

Q60. What assumptions are reflected in the MIRPP Scenario 1 load forecast?

A60. The MIRPP Scenario 1 load forecast changes three assumptions relative to the base case load forecast: EV adoption, building electrification, and weather reflecting climate change.

For EV adoption, the Company used a high-growth case derived from an external expert forecast of new vehicle sales, which was used to estimate future EV registrations. That assumption results in higher EV-related load growth relative to

the Base Case load forecast. The high growth case represents greater EV adoption than assumed in the Base Case load forecast.

For building electrification, the Company applied its high electrification projections, as detailed in Part VIII of my testimony. Those projections reflect increased building-electrification adoption based on the assumptions described in the 2025 Energy Waste Reduction, Demand Response, and Efficient Electrification Statewide Potential Study applicable to DTE Electric's service territory.

Projected climate change impacts were reflected by incrementally adjusting normal weather in each year of the forecast by adding 8.0 additional CDDs and removing 21.9 HDDs annually. These adjustments are based on the average results of the A1 and B2 IPCC emissions scenarios from the models included in the Coupled Model Intercomparison Project Phase 3 (CMIP3) [3].

Q61. What assumptions are reflected in the MIRPP Scenario 2 load forecast?

A61. As described earlier in my testimony, the Company used the MIRPP Scenario 2 load forecast as its Base Case load forecast. That forecast reflects the Company's baseline assumptions for the variables described in Parts II and VIII of my testimony.

Q62. What assumptions are reflected in the DG sensitivity forecasts?

A62. The Company developed 10%, 15%, and 20% DG sensitivities, each designed such that, by 2046, customer adoption reaches specified participation levels relative to

[3] https://ccr.nelson.wisc.edu/visualization-and-tools/central-eastern-north-american-landscape-conservation-cooperatives-lccs-michigan-focus

the Company's preceding five-year average peak demand. The 10% sensitivity reflects the participation level permitted under current law, while the 15% and 20% sensitivities evaluate higher assumed participation levels.

To achieve these adoption levels, the Company assumed increasing incentive levels across the sensitivities, covering approximately 65%, 80%, and 85% of installed costs, respectively. I also provided the installed cost assumptions underlying these incentive levels to Witness Manning for evaluation in the IRP modeling.

Q63. What assumptions are reflected in the Low, Medium, and High Large Load Growth sensitivity forecasts?

A63. The Low Large Load Growth forecast adds approximately 2.0 GW of prospective large load growth during 2033 through 2034 beyond the loads associated with OACS and Google that are reflected in the Base Case load forecast. The Low Large Load Growth forecast therefore reflects approximately 4.4 GW of total large load.

The Medium Large Load Growth forecast adds approximately 5.9 GW of prospective large load growth during 2033 through 2037 beyond the loads associated with OACS and Google LLC reflected in the Base Case load forecast. That is approximately 3.9 GW more than the prospective large load growth reflected in the Low Large Load Growth forecast and results in approximately 8.3 GW of total large load.

The High Large Load Growth forecast adds approximately 9.3 GW of prospective large load growth during 2033 through 2040 beyond the loads associated with OACS and Google reflected in the Base Case load forecast. That is approximately

3.4 GW more than the prospective large load growth reflected in the Medium Large Load Growth forecast and results in approximately 11.7 GW of total large load. Consistent with the MIRPP and IRP filing requirements, the Company applied a probabilistic methodology to known interested large load opportunities to develop aggregate forecast levels representing a reasonable range of potential outcomes. These levels were based on the information available when the forecasts were completed and were used to develop the aggregate Low, Medium, and High Large Load Growth forecasts. Inclusion of a prospective project in this methodology does not indicate that the project is contracted or will ultimately take service. Witness Manning describes how these forecasts were used in the corresponding IRP modeling sensitivities.

Q64. What assumptions are reflected in the High Load Growth sensitivity forecast?

A64. The MIRPP Scenario 2 sensitivity requirements[4] provide: "For the filing utility's load obligation, increase the energy growth rate by at least a factor of two above the base case energy or 0.5% (whichever is larger, but independent of any load growth from data centers) on a per customer basis. Adjust demand accordingly. For the region included in the scenario utilize load growth that is consistent with the most recent MISO futures."

[4] Dec 18, 2025 Order in Case Nos. U-21570 and U-21867, page 89 MPSC order U-21570 and U-21867

The MIRPP Scenario 1 load forecast satisfies these requirements and, therefore, was also used as the High Load Growth sensitivity forecast.

Q65. What assumptions are reflected in the Atypical Weather sensitivity forecast?

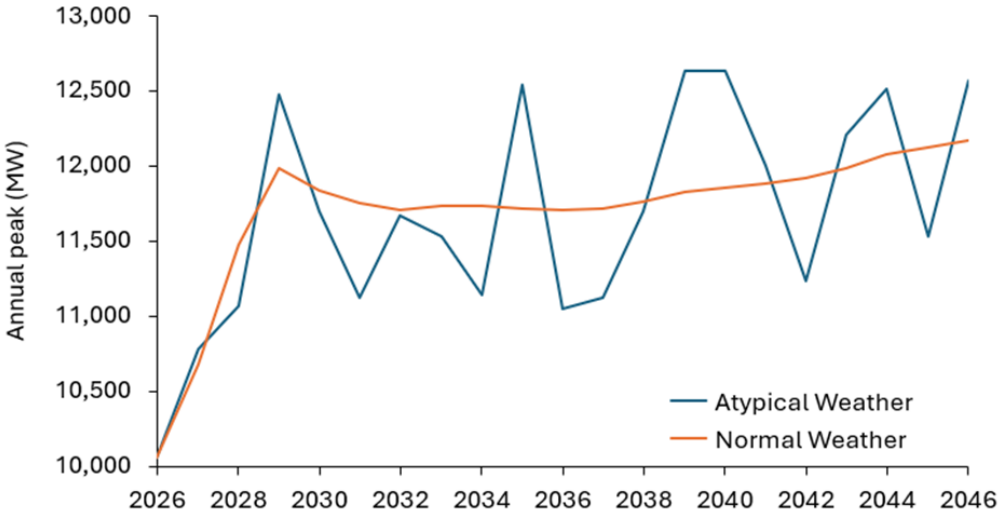
A65. The MIRPP requires the Company to: "Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions."[5]

To develop the load forecast inputs for this sensitivity, I used actual historical weather in place of the normalized weather described in Part II of my testimony. Specifically, actual weather from 2010 to 2024 was mapped for each historical weather year to a corresponding future forecast year. Because this approach preserves the variability inherent in observed weather patterns, it introduces greater year-to-year fluctuations in the forecasted energy requirements and peak demand. Figure 9 illustrates how the annual peak fluctuates from year-to-year in the Atypical weather sensitivity.

[5] Ibid, page 84

Line No.

Figure 9 Base scenario bundled peak (MW)



The historical calendar was preserved in this mapping process to maintain the integrity of weekday and weekend alignment, as well as to appropriately account for leap years. This approach avoids distortions that could arise from mismatched calendar structures and ensures a more accurate representation of load patterns under atypical weather conditions.

The analysis used 15 historical weather years. The MIRPP requires the sensitivity to address atypical weather conditions occurring at least as frequently as once in ten years, but it does not limit the analysis to 10 historical years. The historical weather inputs (including HDDs, CDDs, wind speeds, and global horizontal irradiance (GHI)) were used to develop both the load forecast and the associated wind and solar production profiles.

Line No.

The solar production shapes derived from historical GHI were incorporated into the DG projections embedded within the load forecast. To ensure consistency across planning analyses, the same set of historically derived wind and solar production profiles, based on aligned wind speed and GHI data, were also provided to Witness Manning for use in the EnCompass model as part of this sensitivity.

Q66. What assumptions are reflected in the Low Load Growth sensitivity forecast?

A66. The MIRPP Scenario 2 sensitivity requirements[6] provide that "EV adoption and electrification are slower than expected. Demand and load growth rates are consistent with the 5-year historical growth rates prior to 2020 and the onset of COVID-19".

For EV adoption, the Company utilized a low-growth case derived from an external expert forecast of new vehicle sales, which was used to estimate future EV registrations. That assumption results in lower EV-related load growth relative to the Base Case load forecast. This scenario is intended to represent a future in which conditions are less favorable for EV adoption, including persistent lack of incentives, public charging speeds and costs not widely accepted by consumers and lack of regulation that drive EV sales.

For building electrification, the Company applied its low electrification projections, as detailed in Part VIII of my testimony. The Low Load Growth sensitivity forecast reflects a future in which building electrification continues to increase, but at a slower pace than in the Base Case load forecast, reflecting earlier market maturity relative to Base Case assumptions.

[6] Dec 18, 2025 Order in Case Nos. U-21570 and U-21867, page 89 MPSC order U-21570 and U-21867

Q67. What assumptions are reflected in the Customer Choice sensitivity forecast?

A67. The Company developed an Alternative Electric Choice sensitivity forecast to assess the potential load forecast effect if customers do not migrate to alternative electric suppliers at the level reflected in the Base Case load forecast. This sensitivity assumes Customer Choice participation does not increase with future load growth. Customer Choice load is maintained at the forecasted 2028 level for all subsequent years of the planning horizon. Under these assumptions, bundled peak demand increases by more than 200 MW by 2030 and nearly 300 MW by 2046, reflecting the additional load the Company would need to serve if customer choice participation does not expand commensurately with future load growth. The assumptions underlying this sensitivity forecast are described here, while Witness Manning discusses the resulting modeling impacts and resource planning implications.

PART VII: IRP AND DSP ALIGNMENT

Q68. What is meant by "alignment" between the IRP load forecast and the DSP load forecast?

A68. In this context, "alignment" refers to the use of a consistent set of underlying inputs, assumptions, methodologies, and projections of energy consumption across both the IRP and DSP load forecasts. Alignment includes consistent treatment of key drivers of changing customer behavior such as customer growth, economic conditions, building electrification, DG, EVs, and weather. It also includes the use of a common forecasting framework that connects the system-level and distribution-level forecasts and ensures they are internally consistent.

Q69. Why is alignment between the IRP load forecast and DSP load forecast important?

A69. Alignment between the IRP load forecast and DSP load forecast is important because it ensures that the Company's generation resource planning and distribution system planning are based on a consistent and unified set of underlying inputs, assumptions, and projections. This alignment enables the Company to effectively translate system-level load forecasts used for resource planning into the localized forecasts required for substation and circuit-level distribution planning, thus ensuring that both planning processes are coordinated and internally consistent.

Q70. How does the IRP load forecast align with the load forecast used in the Company's 2026 DSP filed in Case No. U-22104?

A70. As introduced in Case No. U-21193 and described in further detail in Case No. U-22104, the Company's Integrated Forecasting Solution (IFS) enables alignment between the load forecast for the IRP and the load forecast used in the 2026 DSP.

As outlined in Section 5.1 of the Company's 2026 DSP, the IFS serves as a shared forecasting platform that centralizes and standardizes load forecasting inputs across planning processes and produces 8,760-hourly load forecasts at both the system level and the substation and circuit levels using the same inputs, assumptions, and weather patterns applied in the IRP system-level forecast.

Specifically, the IFS applies the same underlying methodologies and inputs described in Parts I and II of my testimony to both the IRP and DSP forecasts,

ensuring that the system-level projections used for resource planning are directly connected to geographically granular forecasts used for distribution planning.

At a more detailed level, the IFS develops reference hourly load forecasts for substations and circuits using the same regression-based, bottom-up hourly load forecasting methodology described in Part II of my testimony, with the primary distinction being that historical substation and circuit loads are modeled rather than aggregate customer classes.

To maintain consistency between system-level and distribution-level planning, the IFS also applies the same hourly load shapes used in the IRP for residential and commercial for projecting localized customer growth, as well as for DG, BESS and EV charging. These load shapes are then scaled to reflect circuit- and substation-specific adoption assumptions and are layered onto the reference hourly forecasts for each circuit and substation.

By linking these forecasts within a single framework, the IFS enables the Company to model not only the total magnitude and timing of load growth, but also how that load is distributed across substations and circuits throughout the system, thereby bridging system-level and location-specific planning needs.

Q71. More specifically, how do the load forecast scenarios developed in the 2026 DSP align with the load forecast scenarios developed in the IRP?

A71. The load forecast scenarios in the IRP and DSP are aligned in a similar manner, while recognizing that each process has distinct filing requirements and supports

different planning objectives. Importantly, the base case load forecast assumptions are identical across the IRP and the DSP. The primary difference is the evaluation of scenarios, which reflects the distinct requirements of each filing.

Under the Commission's IRP filing requirements, electric utilities are required to evaluate a range of defined scenarios and sensitivities, including variations in load growth, electrification, DERs, and other key drivers that influence system demand and resource planning decisions. The IRP filing requirements are prescriptive and include specific, defined scenarios. In contrast, the DSP filing requirements emphasize distribution system planning at the circuit level, including a more general and less prescriptive evaluation of load forecasts under multiple conditions, specifically lower and higher levels of electrification.

Accordingly, although the IRP and DSP apply different scenario frameworks to meet their respective regulatory requirements, they are grounded in a common set of load forecast drivers and assumptions, enabling coordinated planning across both system-level and distribution-level analyses.

Q72. Can you explain more specifically how the Company aligned the DSP scenarios with the IRP scenarios?

A72. Yes. Although the requirements for IRP scenarios are structurally different from the requirements for the DSP, the Company has performed an alignment process in some instances to ensure that comparable load forecast assumptions are consistently reflected across both proceedings.

Specifically, the low and high load electrification assumptions in the respective sensitivities developed for the DSP scenarios are consistently reflected in the IRP scenarios. For example:

- The Low Electrification scenario in the DSP, which reflects lower levels of electrification, is aligned with IRP Sensitivity 2b under Scenario 2 "Low Load Growth"
- The High Electrification scenario in the DSP, which reflects increased levels of electrification, is aligned with IRP Scenario 1.

The primary distinction is that IRP Scenario 1 includes additional requirements related to climate change, which are not incorporated into the DSP due to the differences in the respective filing requirements.

This alignment ensures that the range of potential future load conditions evaluated in the IRP is consistently translated into distribution-level planning scenarios, even though the DSP presents those scenarios in a format tailored to distribution system planning requirements.

Q73. What are the benefits of this integrated forecasting approach for regulatory planning and reliability?

A73. This integrated forecasting approach described above, which relies on the alignment of the IRP and DSP load forecasts, provides several important benefits.

First, it ensures technical alignment between generation resource planning and distribution system planning, allowing system-level IRP projections to be consistently translated into localized distribution impacts.

Second, it enhances transparency and consistency across regulatory filings, including IRPs, DSPs, and other planning proceedings such as Transportation Electrification Plans (TEPs), by using a shared set of inputs and a common data foundation.

Finally, the integrated approach supports the consistent representation of emerging technologies, such as DG, BESS, and EVs, across both system-level and distribution-level forecasts, which improves the Company's ability to plan for long-term reliability, resilience, and evolving customer demand.

PART VIII: DG, EVs, BUILDING ELECTRIFICATION, and EWR ASSUMPTIONS

Part VIII Section I: Distributed Generation

Q74. What type of DG resources were included in the forecast?

A74. The Company, for purposes of the forecast, is defining DG as customer-sited resources that are: 1) interconnected to the distribution system on the customer's side of the utility's service meter (behind-the-meter) and 2) installed to offset site load with incidental export. For forecasting purposes, the projected additional DG resources were assumed to be solar photovoltaics (PV) with or without paired BESS.

Q75. What is the current state of DG in DTE Electric's service territory?

A75. As of year-end 2025, the DG program includes approximately 12,000 residential and non-residential customers, representing over 103 MW of AC nameplate capacity. This represents less than 1% saturation of the Company's total customer

base and in-state peak load, well below the legislated 10% cap[7]. Nearly all installations (99.9%) are solar PV. In addition, more than 38 MWh of BESS energy capacity is paired with solar installations within the program, approximately 97% of which are residential customer installations.

With the DG program succeeding the former Net Metering program, incremental DG installations have remained relatively consistent from the program's inception in 2019 through 2024. Annual additions have averaged approximately 11 MW, with limited variability, ranging from a low of 8 MW to a high of 13 MW. In 2025, incremental installations reached an all-time high of 20 MW. This increase was likely driven by customers accelerating installations in advance of the anticipated expiration of the federal Investment Tax Credit (ITC), which subsidized 30% of installed system costs.

Q76. How was the DG forecast developed and how was it applied to the load forecast?

A76. The DG outlook was developed using the Company's historical residential and non-residential interconnection data. The forecast begins with an assessment of historical and projected PV economics for both customer segments. Key variables including, but not limited to, capital costs, operating and manufacturing costs, tax credit schedules, and electricity prices, are used to determine PV economics. These economics, integrated with a logistic function, serve as the primary explanatory variable in a regression model, with historical interconnections as the dependent variable, to project future levels of DG adoption.

[7] U-20890 DTE Electric Company's 2025 Annual Interconnection Report 2025 Interconnection report; Program space is determined through the utilities average five-year in-state peak load

Separate forecasts are developed for residential and non-residential customers. Historical and forecasted DG levels are then incorporated directly into the load forecast as an additional end-use in the SAE framework for residential and small C&I customers.

BESS attachment rates are applied to the projected DG adoption to estimate future BESS capacity. These attachment rates are used to quantify the incremental storage capacity associated with customer-sited generation and to model the resulting impacts on customer demand, including energy arbitrage and the effect it may have on peak demand.

Q77. What is the outlook for DG?

A77. The market for DG is expected to continue growing gradually over the long term. Near-term adoption is moderated by customer economics, primarily reflecting the elimination of the 30% ITC, while longer-term adoption is supported by continued declines in solar technology costs.

Within DTE Electric's service territory, DG penetration is below 1% saturation of the Company's customer base and remains below the applicable legislative program cap, providing room for additional adoption over the forecast horizon. Under the base forecast, DG capacity is projected to grow to more than 600 MW by 2046. BESS are expected to follow a similar growth trajectory, reaching more than 140 MW of installed capacity by 2046.

To assess the potential system impacts of higher-than-expected DG adoption, the Company evaluated several alternative DG scenarios consistent with the IRP

planning parameters. Specifically, DG program participation equivalent to 10%, 15%, and 20% of system-peak load were modeled under Scenario 1 to examine outcomes beyond both the base forecast and the current legislative cap.

Part VIII Section II: Electric Vehicles

Q78. How is the Company defining EVs as it relates to the forecast?

A78. An EV is a vehicle that uses electricity stored in an onboard battery as a primary source of propulsion in place of a conventional internal combustion engine fueled by gasoline or diesel. The two primary types of EVs relevant to the Company's forecast are battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). BEVs operate exclusively on electricity while PHEVs combine an electric motor and battery with a smaller internal combustion engine.

Q79. What is the current market size for EVs in DTE Electric's service territory?

A79. In DTE Electric's service territory of Southeast Michigan, EV sales have grown at a compound annual growth rate (CAGR) of nearly 57% from 2021 to 2025 with approximately 48,000 EVs sold in 2025, compared to about 8,000 EVs in 2021. In 2025, 86% of the newly sold EVs in Michigan are registered in DTE Electric's service territory and 80% of these are all-electric. There are approximately 114,000 EVs registered in Southeast Michigan[8].

Q80. How did the Company forecast load growth from EVs?

A80. The EV load forecast, which includes both plug-in hybrid and full battery electric vehicles, is built from the product of three core variables across five vehicle segments.

[8] Reported from 2025 Vehicles in Operation

The core variables are:

1. Vehicle stock: The total number of vehicles on the road per vehicle segment
2. Vehicle miles traveled (VMT): Average annual miles traveled per vehicle segment for electric vehicles
3. Electric intensity: Average electric consumption in kWh/mile per vehicle segment

The five vehicle segments are:

1. Light-duty used for personal driving
2. Light-duty fleet
3. Medium-duty fleet
4. Heavy-duty fleet
5. Buses

Various data sources were used to arrive at the projections for EV load. Historical vehicle registration data was utilized as it provides baseline data on vehicle adoption, total vehicle stock, and purchase trends unique to the Company's service area. External market-share projections purchased from the Electric Power Research Institute (EPRI), specific to DTE Electric's service territory, were leveraged to estimate future EV sales and registrations which are then accumulated to project total EV stock for each segment. VMT and electric intensities were derived through a combination of internal estimates based off service area specific historical registration data, EPA fuel economy ratings, and EIA projections[9], tailored to each vehicle segment.

[9] U.S. Energy Information Administration - EIA – Fleet Truck Stock
U.S. Energy Information Administration - EIA – Light-Duty Energy Use
U.S. Energy Information Administration - EIA – Light-Duty Vehicle Sales
U.S. Energy Information Administration - EIA – Light-Duty Vehicle Miles Traveled

For each vehicle segment the EV load is calculated as:

$$\text{EV Load} = \text{Number of Vehicles} \times \text{VMT} \times \text{Electric Intensity}$$

This segment-level load forecast is then translated into customer classes. For personal vehicles, the forecast assumes that most charging today primarily occurs at residences under residential rates. As adoption grows, charging is expected to shift increasingly toward commercial rate classes, including workplace, public charging stations, and direct current fast charging (DCFC). For fleet vehicles and buses, charging is assumed to occur entirely at commercial and industrial establishments, under a mix of small and large businesses.

Q81. What is the outlook for EVs?

A81. EVs are projected to be among the fastest-growing end-use among residential and commercial customers in DTE Electric's service territory. The EV market as of year-end 2025 reflected 12 percent of new vehicle sales and is projected to account for more than 40 percent of new vehicle sales by 2046.

In the near term, EV adoption is expected to face moderate headwinds due to the September 2025 sunset of $7,500 federal EV tax credits, which is anticipated to temper demand and slow the pace of adoption relative to recent historical growth. Nevertheless, EV sales are projected to maintain forward momentum over the next several years, albeit at a more moderate rate than previously expected, as underlying market fundamentals, including expanding model availability, continued infrastructure investment, and long-term cost declines, remain supportive

Line No.

of continued adoption. Consistent with analyses previously presented in the Company's 2026 Transportation Electrification Plan and 2026 electric rate case, the forecast incorporates the impacts of federal incentive changes.

Given the relative infancy of the EV market and the uncertainty associated with key adoption drivers such as public policy, customer preferences, and automotive manufacturer product strategies, the Company evaluated multiple EV adoption scenarios to assess the potential impacts on load growth and resource planning. Consistent with the Company's Transportation Electrification Plan, Distribution System Plan, and other planning processes, these scenarios are used to evaluate a range of potential future outcomes. Specifically, the Company assessed three EV adoption trajectories: low, medium, and high. The medium adoption case is reflected in the base load forecast, the low adoption case is utilized for the Low Load Sensitivity, and the high adoption case is incorporated into Scenario 1 and its associated sensitivities.

Table 2 presents the projected energy utilized in the forecast models and resulting peak demand utilized in the forecast models for EVs for the Base Case.

Line No.

Table 2 Cumulative Electric Vehicle Energy and Demand[10]

Year	2026	2031	2036	2041	2046
Energy (GWh)	515	1,798	3,667	6,254	8,672
Coincident Winter Peak Demand (MW)	84	299	595	1,141	1,560
Coincident Summer Peak Demand (MW)	56	207	418	679	1,150

Part VIII Section III: Building Electrification

Q82. What is building electrification?

A82. Building electrification refers to the transition of end-use equipment within residential and commercial buildings from fossil fuel-based technologies to electrically powered alternatives. Common examples include air-source heat pumps (ASHPs), ground-source heat pumps (GSHPs), heat pump dryers, heat pump water heaters, and electric cooking equipment.

Q83. Does the Company's load forecast consider building electrification?

A83. Yes. The load forecast reflects various levels of building electrification as incorporated in the base forecast and in alternative scenarios and sensitivities.

Q84. How was building electrification applied to the forecast?

A84. Similarly to other end-uses, both residential and small C&I building electrification was incorporated directly into the SAE modeling structure as separate end-uses.

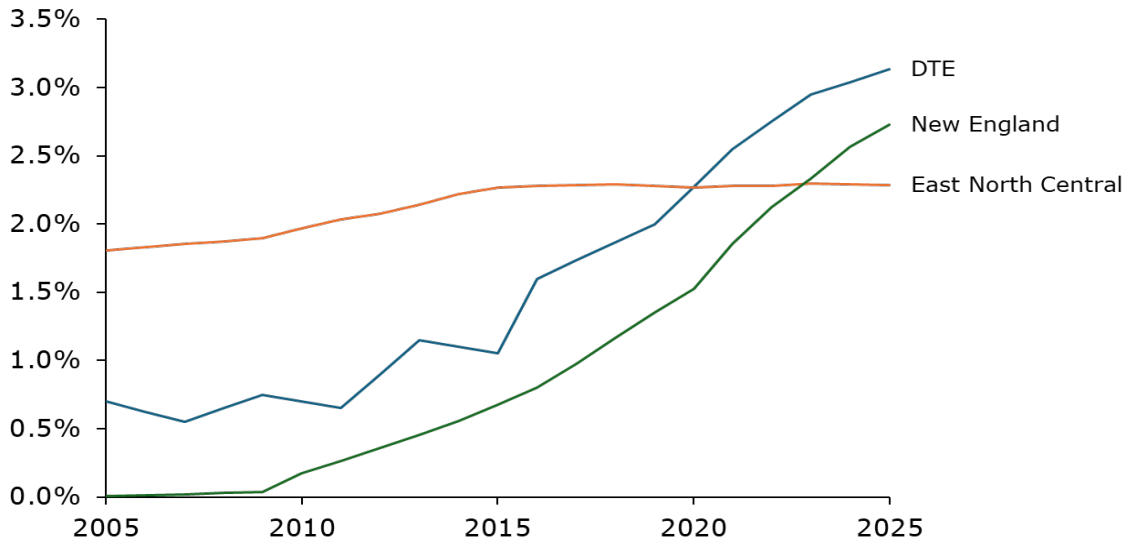
As described in Part II, the Company leverages saturation projections from the EIA's AEO 2025 for the East North Central region. Given the growth in ASHPs

[10] Peak demand impact is coincident with bundled peak demand and includes line losses

Line No.

and GSHPs experienced over the last fifteen years in DTE Electric's service territory, EIA's saturation projections were not utilized due to both the regional inconsistency in historical adoption (as reported by the EIA), as well as EIA projecting declining saturation for the East North Central Region. Instead, in the Base Case, the Company modeled future growth in ASHPs and GSHPs using the New England region projections which are better aligned historically to the Company's adoption levels. Figure 10 displays these historical differences for ASHPs.

Figure 10 DTE vs Regional EIA Historical ASHP Saturations (% of Customers)



Q85. How were alternative scenarios developed for building electrification?

A85. The Company developed both low and high building electrification scenarios for use in the IRP.

The low building electrification projections assume that growth in building electrification continues, but at a slower pace than assumed in the base case. Recent historical years were analyzed to identify observed growth trends, and a logarithmic trend was applied over the remainder of the forecast period to dampen future growth. Projected efficiency improvements in heat pump technology outweigh incremental growth in this scenario resulting in an overall decline in load projections.

The high building electrification projections were developed using the 2025 Energy Waste Reduction Demand Response and Efficient Electrification Statewide Potential Study specific to DTE Electric's service territory, as described further by Witness Kupser and Witness Leuker. This scenario was designed to represent a future in which sponsored programs are in place to incentivize building electrification and to evaluate the potential impacts incentivization could have on adoption.

Q86. What is the outlook for building electrification?

A86. At present, building electrification in the Company's service territory remains limited in penetration and continues to be an emerging market, particularly for space heating applications. The majority of residential, commercial, and industrial buildings currently rely primarily on fuels such as natural gas to meet space heating and process energy needs.

While building electrification is not yet widespread, it is economically viable today for select applications and presents scalable opportunities in Michigan over time. Future adoption is expected to depend on factors such as customer interest, policy,

natural equipment replacement cycles, and improvements in relative economics, either through market-driven trends or targeted incentive programs. Across all three scenarios evaluated in the IRP, growth in building electrification is projected to occur incrementally, positioning electrification as a gradual market transition rather than an immediate or universal shift. Table 3 presents the projected energy utilized in the forecast models and resulting peak demand utilized in the forecast models for building electrification in the Base Case.

Table 3 Cumulative Building Electrification Energy and Demand[11]

Year	2026	2031	2036	2041	2046
Energy (GWh)	196	232	255	275	288
Coincident Winter Peak Demand (MW)	119	134	139	147	148

Part VIII Section IV: Energy Waste Reduction

Q87. How much EWR is included in the load forecast?

A87. Historical and forecast EWR savings are incorporated into the load forecast. This includes historical achievements and their persistent effects over time, as well as new savings assumed to occur over the forecast horizon. As described by Witness Kupser, for purposes of the IRP, the Base Case load forecast assumes EWR savings consistent with Case No. U-21681, the Company's 2026–2029 EWR plan, and Case No. U-21193, the Company's 2022 IRP PCA, which represents the most recently approved long-term EWR savings levels beyond the current EWR plan period. Any EWR savings above these levels were evaluated through the IRP as a supply-side

[11] Peak demand impact is coincident with bundled peak demand and includes line losses

resource. Additional details regarding the EWR levels assessed in the IRP are provided in the testimonies of Witness Manning and Witness Kupser.

Q88. How is EWR incorporated into the load forecast?

A88. EWR is incorporated into the load forecast using two distinct approaches, reflecting differences in data availability by customer class. For residential customers, both historical and forecast EWR savings are available at the end-use level, allowing the forecast to directly adjust end-use projections over time directly into the SAE framework. This results in declining electric intensity as efficiency improvements persist and expand. For C&I customers, where historical and forecast data are less granular across subsectors (e.g., secondary versus primary, automotive vs general manufacturing), EWR savings are incorporated as an explanatory, right-hand-side variable in the regression-based load forecast models.

Q89. Are Demand Response (DR) programs included in the Company's peak load forecast?

A89. DR programs are not explicitly included in the peak load forecast. DR programs, such as Interruptible Air Conditioning, are used to meet the Company's required amount of unforced capacity needed to meet the MISO resource adequacy requirements. DR programs are accounted for on the supply side as load modifying resources. For further detail on resource adequacy requirements see the testimony of Witnesses Burgdorf, Leuker, and Manning.

Q90. Does this complete your direct testimony?

A90. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARKUS B. LEUKER

DTE ELECTRIC COMPANY

QUALIFICATIONS AND DIRECT TESTIMONY OF MARKUS B. LEUKER

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Markus B. Leuker (he/him/his). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am the Director of Load Management and Forecasting in the Business Planning and Development organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science Degree in Business Administration from Xavier University in Cincinnati, Ohio with a concentration in Marketing and Management in 1991. I received a Master of Business Administration Degree from Xavier University in Cincinnati, Ohio in 1998. I have also completed several Company-sponsored courses and attended various seminars to further my professional development.

Q4. What is your professional experience?

A4. I joined the Company in November 2010 as Manager, Corporate Energy Forecasting. Prior to DTE Electric, I worked for IHS/CSM Worldwide as a Sr. Manager, North American Advisory Services where I led the pursuit, development, execution and delivery of key client projects. Some of my experiences at IHS/CSM Worldwide included: Market Research & Analysis, Market Opportunity Analysis, Business Modeling and Strategic Analysis, Regulatory Market Assessment, and Financial and Scenario Analysis. In addition, I worked as North American

Manager, Market Research & Analysis for Visteon Corporation where I managed global coordination of the research function and led a team of researchers in various studies including customer and competitor research, new product creation, and customer satisfaction. I have also had prior experience in the utility industry working as a Senior Analyst at Cinergy Corporation (currently Duke Energy). While at Cinergy, I worked on various non-regulated and regulated marketing activities.

Q5. What are your current duties and responsibilities?

A5. In 2024 I was promoted to Director of Load Management and Forecasting. In this position I am responsible for overseeing DTE Electric's Demand Response (DR) portfolio, which includes short- and long-term strategic development, marketing and management of DR programs and pilots. I am also responsible for overseeing the operations of DTE Electric's Customer Choice program. This includes the billing of Transmission charges for Retail Access (Choice) customers, completing Michigan Public Service Commission (MPSC or Commission) filings per the Retail Access tariff, administering the 10% Cap and Queue list customers, and coordinating with third-party Alternative Energy Suppliers to complete these activities.

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. I am a member of Edison Electric Institute's (EEI) Load Forecasting Group (LFG). The LFG's purpose is to enhance load forecasting capabilities by exchanging information among the group's base of experienced and knowledgeable load

Line No.

forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

Q7. Have you previously sponsored testimony before the MPSC?

A7. Yes. I have sponsored testimony and exhibits before the MPSC in the following DTE Electric cases:

Case No.	Description
U-17049	2012 Energy Optimization Plan
U-17097	2013 Power Supply Cost Recovery (PSCR) Plan
U-17302	2013 Renewable Energy Plan Update
U-17319	2014 PSCR Plan
U-17680	2015 PSCR Plan
U-17762	2016-17 Energy Optimization Plan
U-17767	2015 DTE Electric Rate Case
U-17793	2015 Renewable Energy Plan
U-17920	2016 PSCR Plan
U-18014	2016 DTE Electric Rate Case
U-18111	2016 Amended Renewable Energy Plan
U-18143	2017 PSCR Plan
U-18255	2017 DTE Electric Rate Case
U-18262	2018-19 Energy Waste Reduction Plan
U-18403	2018 PSCR Plan
U-18419	2017 Certificate of Necessity
U-18232	2018 Renewable Energy Plan
U-20162	2018 DTE Electric Rate Case

Line No.		
1	U-20221	2019 PSCR Plan
2	U-20471	2019 Integrated Resource Plan (IRP)
3	U-20561	2019 DTE Electric Rate Case
4	U-18232	2020 Amended Renewable Plan
5	U-20836	2022 DTE Electric Rate Case
6	U-21193	2022 Integrated Resource Plan
7	U-21297	2023 DTE Electric Rate Case
8	U-21534	2024 DTE Electric Rate Case
9	U-21860	2025 DTE Electric Rate Case
10	U-22046	2026 DTE Electric Rate Case

11

12 **Purpose of Testimony**

13 **Q8. What is the purpose of your testimony?**

14 A8. The purpose of my direct testimony is to:

15 • Discuss DTE Electric's existing DR portfolio including residential,
16 commercial and industrial customer programs and tariffs;
17 • Discuss the evolving DR Policy and Planning framework and effects on the
18 Company's DR portfolio
19 • Discuss the current DR programs, and plans to evaluate and develop new
20 products and services to be added to the existing portfolio of DR programs;
21 • Describe the DR assumptions and inputs that were provided to the IRP team
22 to be modeled;
23 • DR resources in the Proposed Course of Action (PCA) and;
24 • Provide capital costs for the time period 2028 - 2030 for which the Company
25 is asking pre-approval.

Line No.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-8	Demand Response Existing Programs for IRP Modeling
A-8.1	Demand Response Inputs for IRP Modeling
A-8.2	Demand Response Capital Costs for Pre-Approval

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes.

Q11. How is your testimony organized?

A11. My testimony consists of the following six (6) parts:

Part I	DR Program Overview and Existing DR Programs
Part II	Evolving DR Policy and Planning Framework
Part III	DR Pilots
Part IV	Summary of DR Assumptions and Inputs
Part V	DR in the Proposed Course of Action
Part VI	DR Capital Costs for Pre-Approval

Part I: DR PROGRAM OVERVIEW AND EXISTING DR PROGRAMS

Q12. What is the purpose of DR?

A12. DR is designed to reduce or shift enrolled customers' energy usage during periods of high demand and/or price to ensure continued reliability and/or reduce power supply costs. DR programs provide special rates or other forms of compensation to incentivize desired customer usage behaviors.

Q13. What are the benefits to customers for participating in DR programs?

A13. DR programs enable electric customers to play a role in the reliable operation of the electric grid and support the clean energy transition. Customers participating in DR programs or tariffs can benefit from lower bills and/or incentives when utilizing these programs. All customers, whether they participate or not, benefit from the overall cost savings that DR can provide through reduced capacity purchases and the reduction in less efficient or more expensive forms of generation.

Q14. What forms of capacity can be avoided through DR?

A14. Reliance on DR can serve as an alternative solution if peaking capacity is needed to meet demand or additional purchases are needed to reliably serve customers.

Q15. What are the benefits of DR to the utility?

A15. The reduction or shift in customer usage from DR programs can provide value to the utility and its customers through DR's contribution to the Company's capacity position and reduction in capacity purchases. In addition, reducing electricity usage when demand is high and margin is tight can result in lower wholesale energy prices.

Q16. What is a DR Event?

A16. A DR Event is a period when DR programs are dispatched to reduce demand and maintain grid reliability. DR Events have been traditionally dispatched by the Midcontinent Independent System Operator (MISO) to help relieve stress during bulk system emergencies, specifically during Energy Emergency Alert Level 2

(EEA-2), but some programs can be dispatched to assist with localized grid constraints or for economic reasons.

Q17. Could you describe the Company's current DR portfolio?

A17. Yes. DTE Electric develops and manages its DR portfolio offering customers a range of options consisting of programs, customer incentives, tariff structures, and education. These programs are based off customer profiles and willingness to curtail or shift energy usage during peak hours. As part of the development process, the DR organization evaluates customer behavior, program acceptance and validates technologies that can deliver benefits to its customers.

The Company's current DR portfolio is made up of interruptible tariffs, programs, and pilots that are available to residential and commercial and industrial (C&I) customers. The goal of the Company's DR portfolio is to deliver cost-effective, measurable demand reductions by effectively engaging customers to reduce or shift their energy consumption when called upon.

Q18. What programs and tariffs are included in the Company's current DR portfolio?

A18. The Company's DR portfolio is made up of CoolCurrents™, Smart Savers, Interruptible Water Heating, and multiple interruptible tariff rates for C&I customers. The participants in the DR programs or on the interruptible tariffs receive a discounted rate or incentive in exchange for reducing their load during DR events

Line No.

Q19. What is the CoolCurrents Program?

A19. CoolCurrents is the program name for the Interruptible Space Conditioning tariff (Rate D1.1) that is available to residential and commercial customers. Customers who enroll in CoolCurrents are equipped with a Load Control Device (LCD) connected to their air conditioning unit(s) or central heat pump that allows the Company to cycle the associated appliance in exchange for a discounted rate. The cycling of the appliance is limited to no more than eight hours in any 24-hour period and events can be called year-round in any of the four MISO seasons. Customers cannot override the dispatch signal, making CoolCurrents a predictable and reliable DR program for the Company. As of September 2026, there are approximately 247,000 residential and commercial customers enrolled in the CoolCurrents program.

Q20. How does the Company market its CoolCurrents Program to potential customers?

A20. The Company continues to grow the program MWs by updating obsolete radio control units (RCU) with new load control devices (LCDs), replacing equipment for existing customers where devices are not in compliance and conduct investigations into causes for devices currently offline and bring them into compliance. The Company does not actively market its CoolCurrents program to new customers. In Case No. U-22046, the Company proposed closing the program to new enrollees as the costs associated with the second meter requirement have been identified as a barrier for new enrollment.

Q21. What is the Smart Savers program?

A21. The Smart Savers program, which is a Bring Your Own Thermostat (BYOT) program, is available to residential and commercial customers who have an existing and eligible Programmable Communicating Thermostat (PCT) installed at their residence or business. In this program, customers enroll their eligible thermostat in the program and agree to let the Company adjust the setpoint on the thermostat up by four degrees during Smart Savers events. Smart Savers events last no more than four hours and can be called between 12:00 pm and 8:00 pm on non-holiday weekdays. The Smart Savers season runs from June 1st through September 30th, and events are limited to 56 total hours annually. Customers can opt out of events and override thermostat settings prior to and during an event. At the end of 2025, there were 95,351 devices enrolled in the Smart Savers program.

Q22. How does the Company market its Smart Savers program?

A22. The Company uses a combination of thermostat in-app marketing, social media, and direct marketing to target customers to participate in Smart Savers.

Q23. What is the Interruptible Water Heating rate?

A23. The Interruptible Water Heating rate (D5) is a tariff available to both residential and commercial customers that use hot water for sanitary purposes (other uses subject to the approval of the Company) and take service under Residential and General Service Rate Schedules. An LCD is installed at the customer's location that turns off the heating element of electric water heaters for up to four hours in any 24-hour period during any MISO season. Participating customers receive a discounted rate on the associated water heating usage. Like CoolCurrents,

customers cannot override the dispatch signal. At the end of 2025, there were 43,678 residential and commercial customers taking service under the Interruptible Water Heating rate.

Q24. Does the Company actively market its Interruptible Water Heating rate?

A24. No, the Company does not actively market the interruptible water heating rate due to the low cost-effectiveness score of the rate. The low cost-effectiveness score is due to the cost of purchasing and installing LCD's, the rate break given to customers, and the corresponding capacity for the program. However, MISO's new rules pertaining to Load Modifying Resources (LMRs) accreditation will be based on availability during MISO's seasonal Capacity At-Risk Hours over the previous year. Given MISO's seasonal Capacity At-Risk Hours can vary in time of day and day of the week, having a resource that is available year-round, twenty-four hours a day, such as the Water Heating program, could be a cost-effective asset for the Company in the future.

Q25. What additional interruptible tariffs does the Company offer to C&I customers to promote participation in demand response?

A25. The Company offers C&I customers six tariffs at a discounted rate in exchange for agreeing to interrupt a portion of their electric load during DR events. Unless otherwise noted, these tariffs are available for interruption year-round in any of the four MISO seasons. The tariffs that are available to C&I customers are as listed:

1. Interruptible General Service Rate (D3.3): Commercial secondary customers can elect to have separately metered service that is subject to

interruption or establish a portion of their load as firm through the product protection feature. This rate is not available to customers whose loads are primarily off-peak. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, economic reasons, or when available system generation is insufficient to meet anticipated system load.

2. Interruptible Supply Base Service Rate (D8): Primary voltage customers who desire separately metered service for a specified quantity of demonstrated interruptible load of not less than 50 kW at a single location can take service under this rate. Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads will lead to a capacity deficiency.
3. Alternative Electric Metal Melting (Rider 1.1): Customers who operate electric furnaces for the reduction of metallic ores and/or electric use consumed in holding operations who provide special circuits can have that load separately metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.
4. Electric Process Heat (Rider 1.2): Customers who use electric heat as an integral manufacturing process, or electricity as an integral part of anodizing, plating, or coating process and who provide special circuits can have that load separately metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.
5. Interruptible Supply Rider (Rider 10): Rider 10 allows customers to elect the amount of interruption they are willing to take under a separate meter. Program participation is capped at a total of 650 MW of enrolled load. Rider

10 is designed for customers of greater than 50 MW at a single location, although at the Company's discretion, and with available capacity, the minimum site requirements can be waived. The Company may order an interruption to maintain system integrity.

6. Capacity Release (Rider 12): Customers are provided with a capacity release payment by subscribing at least 100 kW of load per site location for interruption. The Company may order an interruption to maintain system integrity. The program is only available during the MISO summer season from June 1 – August 31 although the Company is evaluating customer reception for Rider 12 to be made available for the other seasons as well.

C&I customers who take service on an interruptible tariff are subject to financial penalties for not reducing their load to their agreed upon levels during a DR event and are at risk of being removed from an interruptible tariff for underperformance. At the end of 2025, there were 277 C&I customers on an interruptible tariff and an additional 93 customers who participated in the R12 offering in the Summer 2025.

Q26. How does the Company target customers for its C&I interruptible rates?

A26. The Company's Major Account Services (MAS) Team communicates the different rate options to C&I customers and works with them to understand the benefits and expectations of being on an interruptible rate.

Q27. How do the programs and tariffs that make up the Company's DR portfolio fit into the current MISO construct?

A27. The capacity associated with the programs and interruptible tariffs are registered as LMRs to meet the company's resource adequacy requirements (or capacity

obligation) in one or more seasons. The Company's interruptible tariffs (D3.3, D8, R1.1, R1.2, R10) are registered as year-round resources and provide capacity in each season. CoolCurrents and Smart Savers are registered for the spring, summer and fall seasons, while R12 is currently available for the summer season, but the Company is exploring expanding the product to other seasons. All the Company's DR resources are registered with a two-hour notification time, meaning these resources must respond to the MISO instruction to dispatch within two hours.

In the current MISO construct, the Company's LMRs are only dispatched by MISO during system integrity events or better known as MISO Max Gen Event Step 2.[1] CoolCurrents, Smart Savers, Interruptible Water Heating and D3.3 can be dispatched by the Company for other reasons such as economics or localized relief in addition to MISO ordered dispatches.

Q28. How much capacity does the Company's existing DR portfolio account for in meeting MISO's resource adequacy requirements in the 2026/2027 Planning Year (PY)?

A28. DTE Electric registered 520 MW (installed capacity or ICAP) of DR for the summer season, equating to 573 Zonal Resource Credits (ZRCs). The seasonal breakdown of ICAP capacity and ZRCs used to meet resource adequacy requirements in the 2026/2027 PY is in Table 1.

[1] When assessing grid conditions, MISO issues the following notifications: (1) a capacity advisory when MISO forecasts reserve margins of less than 5%; (2) a MaxGen Alert when the reserve margin drops below 1,500 MW in the MISO North sub-region or 500 MW in the MISO South sub-region; (3) a MaxGen Warning when MISO's reserve margin is projected to be negative; and (4) MaxGen Events, Warning when MISO's reserve margin is projected to be negative and Warning level actions are not sufficient, also includes Energy Emergency Alert – Level 1 (EEA-Level 1), Level – 2 (EEA-Level 2), and Level – 3 (EEA-Level 3).

Table 1 2026/2027 PY ICAP Capacity (ZRCs) by Season

Summer	Fall	Winter	Spring
520 (573)	288 (328)	282 (342)	351 (442)

Q29. How does the Company forecast the DR Capacity used to meet resource adequacy requirements?

A29. Beginning with the 2024/2025 MISO Planning Year, the Company changed how it calculates DR capacity in its portfolio to standardize the process and ensure that the Company resources can perform to the expected value reliably when called upon. To forecast the available DR load for the interruptible tariffs, the Company uses previous year's actual interruptible load at the MISO Seasonal Coincident Peak while also considering any known customer changes. For DR programs like Smart Savers and CoolCurrents, the Company uses actual performance data from historical events and a regression model to calculate event performance over a four-hour event period. The lowest load reduction observed during the four-hour period is then used to calculate the capacity that is claimed in the Planning Resource Auction (PRA) to ensure the Company is not overstating the interruptible capabilities, keeping reliability at the forefront of demand response.

Q30. Why does the Company use these methodologies to calculate the amount of capacity available for interruption within the DR portfolio?

A30. One of the requirements set forth by MISO is that, for the Company to register DR resources as LMRs and maintain annual capacity credits, the load reduction from DR must be sustainable for a minimum of four hours. By using actual data that

already includes customer overrides and opt outs, the Company can ensure its DR resources can reliably perform when called upon to the levels needed and communicated to MISO as well as fulfill MISO participation requirements.

Q31. Has this change in methodology affected the amount of capacity the Company claims to meet resource adequacy requirements?

A31. Yes, when this methodology change was first implemented with the 2024/25 MISO Planning Year, the accredited capacity associated with the Company's portfolio was reduced by approximately 25% for the summer season from the prior year as demonstrated in Witness Farrell's testimony in case no. U-21919 (2024/2025) and Witness DeKimpe's testimony in case no. U-21658 (2023/2024).

Part II: EVOLVING DR POLICY AND PLANNING FRAMEWORK

Q32. What changes are being explored by MISO related to LMRs?

A32. On April 4th, 2025, MISO proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff, beginning with the 2028/2029 Planning Year to improve availability, operational effectiveness, and accreditation of demand response and emergency only resources and on June 18, 2026, FERC accepted tariff changes. Proposed tariff revisions included changing how LMRs are accredited, proposed dividing LMRs into Type I and Type II, adding testing requirements, and modifying the requirement for the number of interruptions per season. The Federal Energy Regulatory Commission (FERC) accepted the proposed tariff revisions, subject to condition on June 18, 2026, and will be implemented beginning with the 2028/29 MISO Planning Year. These revisions are discussed by Witness Burgdorf.

Q33. How might these MISO changes affect the DR portfolio?

A33. The MISO changes will likely lead to lower accreditation of MISO LMR resources due to resources being accredited on availability. Some customer attrition is expected within the C&I class, though it is difficult to calculate how much, due to the increased testing requirements and Type I and Type II bifurcation, which could result in a smaller DR portfolio. MISO has also implemented changes that would increase penalties for underperforming resources that could also affect the DR portfolio.

Q34. Could you discuss how the change in accreditation calculation could affect the accredited capacity associated with the Company's DR portfolio?

A34. Yes. Beginning with the 2028/2029 MISO Plan Year, resources will be accredited by MISO based on their availability during a season's resource adequacy hours, defined as the 65 hours with the tightest operating margin. The tightest hours will be made up of resource adequacy hours and capacity at risk hours and can occur during any hour of a season, including nights and weekends, which will add additional variability to a resource since actual availability can fluctuate by time, day, week or month. In addition, some programs that the Company currently offers are not available 24 hours a day and 7 days a week, so if a tight hour occurs outside of the availability of a program, the accreditation of that program will be reduced.

Q35. Why does the Company believe that the LMR reforms could cause customer attrition?

A35. The Company believes LMR reforms could cause customer attrition by increasing the number of events called, preventing customers from opting out of testing, and

increasing penalties for underperformance. As discussed by Witness Burgdorf, LMRs will be divided into Type I and Type II, both of which introduce requirements that could cause attrition. Type I LMRs will have up to six hours to deploy after being notified by MISO but are expected to be deployed more frequently. Type II resources are not expected to be deployed as frequently, but resources will have only 30 minutes to deploy after being notified by MISO. Both an increase in deployment frequency if registered as a Type I resource and a shortened deployment notification timeframe if registered as a Type II resource could increase customer attrition. Furthering the possibility of attrition is the inability for customers to opt out of testing. Testing for C&I customers requires that operations for their facility be restricted or halted to meet performance obligations. The ability to opt out of testing previously meant customers would not be subject to the financial risks associated with restricting or halting facility operations. However, no longer being able to opt out of testing could add financial risk for the customer that outweighs the benefits of participating in DR, leading to customer attrition. Finally, increasing financial penalties for underperformance, penalties which would be passed on by the Company to underperforming customers, could add financial risk to the customer. The financial risk of increased penalties could outweigh the benefits of participating in DR, leading to customer attrition.

Q36. Is the Company taking any actions in response to MISO's LMR reforms?

A36. Yes. The Company understands that the MISO changes will affect its DR portfolio and the customers who participate in demand response offerings, especially C&I interruptible customers. To ensure the Company still has a robust portfolio of DR offerings, the Company will continue to analyze and design new DR programs that

will fit within the MISO construct and will appeal to customers and make sure reliability is at the forefront of its DR offerings. The Company also will explore the expansion of its current programs to increase dispatch availability. In addition, the Company has taken steps to educate its C&I customers on the MISO changes and gather feedback to make sure the changes are fully understood well before the anticipated effective date of September 1, 2027.

Q37. Has the Company communicated to its interruptible customers on the MISO LMR reforms?

A37. Yes. The Company began communicating and educating its C&I customers on the proposed changes and to gather feedback well before the LMR reforms were officially filed with FERC. Now that the reforms are finalized, the Company will make sure the changes are effectively communicated to its customers before the effective date of September 1, 2027, affecting the 2028/2029 Planning Year.

Part III: DR Pilots

Q38. What are the Company's plans for future DR programs?

A38. DTE Electric is conducting additional DR pilots that meet the definition and objective criteria for pilots established by the MPSC in Case No. U-20645 and encompass residential, commercial, and industrial customers. Based on the results of these pilots and of utility benchmarking efforts, the Company expects to identify other alternative DR programs that may become economic and technically viable alternatives to generation capacity, have an appropriate level of customer adoption potential, and are cost-effective for customers. While the Company intends to learn as much as possible through benchmarking of other pilots and programs and

leverage the knowledge of vendors who have experience in implementing DR programs, it is considered best practice to conduct actual pilots before launching a new full-scale program. These pilots seek to identify how the Company's unique customer base will react to specific marketing efforts, program design features, and other characteristics that are dependent on DTE Electric's unique combination of systems, equipment, tariffs, programs, and processes.

Q39. What is the Company's overall approach to developing and managing the ongoing and future DR pilots?

A39. The Company has several successful, long-term programs which support its peak-reduction objectives, and many other pilot efforts through which the Company explores diverse opportunities to engage customers and reduce peak load. However, the Company's DR offerings and customer engagement should not remain static over time, and the continued development of pilots is critical to ensure a pipeline of learnings to support future programs and to present customers with the best program offerings. To support ongoing pilot efforts, the Company needs to remain agile enough to efficiently redeploy DR pilot spending and resources as capacity needs change, customer behaviors evolve, program acceptance is assessed, or other more cost-effective technologies and opportunities arise in the near future. This flexibility will ensure DTE Electric is well positioned to expand existing or future programs to respond to changing market conditions and customer behavior. The Company continues to evaluate alternative programs that may emerge as a result of insights from pilots or utility benchmarking efforts. In the coming years, the Company expects to continue developing new pilots that may become cost-effective programs with an appropriate level of customer adoption potential.

Q40. What DR pilots is the Company currently conducting?

A40. The Company is currently conducting an Electric Vehicle (EV) pilot, a Vehicle to Home (V2H) pilot, a C&I Battery storage pilot, and a pilot with Renew Home in which micro adjustments are made to customers thermostats. The Company has also proposed a Virtual Power Plant (VPP) pilot in Case No. U-21653 that utilizes residential batteries.

Q41. Can you describe the EV pilot?

A41. Yes. The EV pilot, known as Smart Charge, has evolved from a DR-only pilot where a signal was sent to stop a participating EV from charging to an active managed charging pilot.

Originally launched in 2019, Smart Charge was designed to assess the effectiveness of Open Vehicle Grid Integrated Platform (OVGIP) concept to integrate EV charging with grid objectives through DR. This initial pilot design ran until May 2023.

After completion of the initial design, the Company modified the focus of the pilot to incorporate active managed charging, starting in July 2023. One of the main reasons the Company transitioned to active managed charging was due to the mandatory roll out of residential electric time-of-use (TOU) rates in March 2023. In this phase of the pilot, the Company's active managed charging approach ties each participant's enrollment to their specific TOU rate schedule and automatically initiates charging to occur during their off-peak rate period when it's the lowest cost for them and most beneficial to the system.

Q42. Have any changes been made to the pilot design since its initial implementation?

A42. Yes. Throughout 2023 and 2024, the Company continued its partnership with Ford, General Motors (GM), and BMW through the OVGIP while adding a new partnership with WeaveGrid. WeaveGrid is a platform that connects utilities, original equipment manufacturers (OEMs), and EV drivers and is the platform that is used to enroll eligible Tesla drivers into the Smart Charge pilot.

In 2024, it was announced that OVGIP was being terminated and ChargeScape LLC was taking over all utility pilots/programs that were originally managed under this platform. During the transition to ChargeScape, GM decided to step away from participating in EV pilots and programs with their utility partners to allow internal evaluations to take place on GM's position in the EV market. Beginning in 2025, all Ford and BMW Smart Charge participants seamlessly transitioned from OVGIP to the ChargeScape platform with zero impact to customers in terms of daily active managed charging. Throughout 2025, Smart Charge continued to operate as an active managed charging pilot, with eligibility expanding by adding ChargePoint, Wallbox, and Emporia Electric Vehicle Supply Equipment (EVSE) as eligible chargers to participate through the WeaveGrid platform.

Q43. What is the current state of the Smart Charge pilot?

A43. In 2026, both ChargeScape and WeaveGrid are implementing additional data ingestion in the daily managed charging signal dispatching that will be used to protect DTE Electric's distribution assets. The goal is to enable peak demand reduction across five (5) synthetic transformer groups and two (2) synthetic circuit

groups per platform to predict when overloading is expected to occur and when upgrades are necessary on each asset as EV adoption continues to grow in DTE Electric's service territory. This data ingestion will be leveraged to optimize charging schedules in conjunction with system constraints.

Q44. What are the next steps with the Smart Charge pilot?

A44. The Smart Charge pilot is being extended through 2030, with WeaveGrid serving as the standalone platform provider. The next phase of Smart Charge will focus on quantifying distribution value. The Company will seek to recruit customers located in constrained areas of the system that may benefit from managed charging schedules. The Company intends to evaluate the pilot annually to determine whether Smart Charge should be scaled to a full program.

Q45. What is Vehicle-to-Home technology?

A45. Vehicle-to-Home or commonly referred to "V2H" is technology that allows bi-directional electric vehicles to operate as a flexible demand response resource. V2H technology allows for a portion or whole home's electric load to be supplied by a bi-directional electric vehicle battery.

Q46. Can you describe the V2H pilot?

A46. Yes. In December 2025, the Company partnered with Ford to evaluate the potential for bi-directional electric vehicles to operate as a flexible demand response resource. The pilot enrolled 10 Ford employees and called 25 pre-scheduled events through August 31, 2026. These events are designed to test the ability of customer-owned electric vehicles to reduce net household load during periods of

system need, while also assessing customer participation, operational feasibility, and overall grid benefits. Participants are eligible to earn up to $400 through a combined up-front and pay-for-performance incentive structure tied to event participation. During a V2H event, participating Ford employees connect their Ford F-150 Lightning EV to a bi-directional charger, enabling the EV battery to discharge electricity and serve the whole home load for a specified period. By offsetting customer demand from the grid, these events provide DTE with insight into the magnitude, duration, and reliability of load reductions that V2H technology could deliver as part of a future demand response portfolio. Individual events range from one to four hours and are conducted on non-holiday weekdays at varying times of day to evaluate performance across different grid conditions. Lessons learned from this pilot will inform the scalability, cost-effectiveness, and potential integration of V2H technology into DTE's broader demand response and load management strategies.

Additionally, DTE has signed with GM to expand V2H offerings to a maximum of 30 GM employees. The pilot is similarly designed to the Ford pilot, with the ability to call up to 50 discharge events within the 12-month pilot period. These discharge events will be a mix of pre-scheduled and ad-hoc events to test customer availability and receptiveness. The first dispatch event was called in July 2026.

Q47. What are the next steps with the V2H pilot?

A47. The V2H pilot is currently being evaluated for the Ford employee participants who have been participating since December 2025. The GM employee participants began testing in July 2026 and are expected to remain in the testing phase through

July 2027. The evaluations for both groups will help the Company and the participating OEMs determine the short-term and long-term value of V2H technology, including customer electric vehicle availability and the potential for the technology to alleviate demand on the grid.

Q48. Can you describe the C&I battery storage pilot?

A48. Yes. The battery energy storage pilot is a behind-the-meter (BTM) lithium-ion phosphate battery energy storage system (BESS) at two customers' sites. It is designed to test the ability to achieve peak demand shaving or shifting during DR events. The Company is targeting a two-year pilot period following installation and commissioning of the batteries.

Q49. What is the status of the C&I battery storage pilot?

A49. In 2025, factory acceptance testing (FAT) for the first BESS was completed. The Company worked with Hitachi and GTI to review and finalize the design for BESS skid. GTI completed manufacturing of the first skid and all BESS components, not including the batteries, were shipped to GTI to begin integration of the components into the skid. GTI delivered the first skid to DTE in April 2026 for commissioning. As of September 2026, commissioning of the first skid is ongoing.

Q50. Once the batteries are commissioned, what are the next steps in the C&I battery pilot?

A50. Once the batteries are commissioned, they will be installed at customer sites and pilot operations will begin. The initial proposed event schedule includes no more than 30 planned DR events per year and five short notice DR events, with at least

one-hour customer notice, per year. As mentioned previously in my testimony, the pilot will last approximately two years post-installation and test the ability to achieve peak demand shaving or shifting during DR events. The pilot also aims to assess the battery's ability to reduce demand charges and overall bills, provide operational experience with installation and control interfaces, gauge customer interest in hosting or scaling storage, assess shared control feasibility, and inform future tariff development through better understanding of storage value streams, compensation models, and wholesale market integration. Upon conclusion of the pilot, the customer will have the option to purchase, lease, or have the battery removed from the site.

Q51. Can you describe the thermostat micro adjustment pilot with Renew Home?

A51. Yes. In July 2026, the Company launched a pilot with Renew Home in which small adjustments are made to customers central air conditioners that are controlled by Nest thermostats. The overall objective of the pilot is to determine the viability of micro adjustments and the impact on peak load reduction. The pilot includes approximately 5,000 customers who have opted in through their thermostat. The pilot will be evaluated for the remainder of 2026 before a determination is made to expand to additional customers in 2027.

Q52. What is a Virtual Power Plant (VPP)?

A52. The United States Department of Energy (DOE) defines VPPs as an aggregation of resources that can balance electrical loads and provide utility-scale and utility-grade grid services like a traditional power plant.

Q53. Is the Company proposing to pilot a VPP?

A53. Yes. The Company filed a VPP pilot proposal, which focuses on a VPP using residential customer-owned batteries, through MPSC's Expedited Pilot Process (EPP) that was approved in Case No. U-20898. The application was filed in Case No. U-21653 on June 18th, 2026, which began the 90-day pilot review process. Pending approval, the pilot is scheduled to launch in the Fall of 2026.

Q54. Can you describe the residential battery VPP pilot?

A54. Yes. The proposed pilot will leverage up to 100 residential batteries located within the Veridian at County Farms community ("Veridian") in Ann Arbor, Michigan. Each residence within Veridian comes standard with a suite of energy efficient infrastructure, including solar panels and battery storage. The batteries installed at the residences are manufactured by sonnen Inc. and provide 4.8 kW of power along with 20 kWh of energy storage. The residences come standard with one battery, however there are several potential participants who have installed additional batteries at their residence. The Company is also leveraging sonnen's edge distributed energy resource management system (DERMS) to manage the orchestration of the batteries during the duration of the pilot.

Q55. What is the Company evaluating with respect to the residential VPP pilot?

A55. The Company's evaluation focuses on three key objective areas: customer experience, operational performance, and cost-effectiveness. Specifically, the customer experience objective will focus on bill impacts, incentives, and overall satisfaction with the pilot. Operational metrics such as capacity/energy reduction, optimal battery state of charge, battery availability, and customer charging patterns

will also be evaluated. Finally, the Company is planning to use the levelized-cost-of-capacity methodology currently used to evaluate demand response programs and the MPSC's recently released Benefit Cost Analysis (BCA) tool incorporating benefits such as, but not limited to, capacity avoidance, energy reduction, ancillary services, and avoided transmission and distribution costs to quantify cost-effectiveness.

Q56. Could you discuss how the VPP pilot will operate?

A56. Yes. The Company will use the sonnen DERMS system to orchestrate the batteries at the Veridian site. The batteries will be dispatched at the same time to reduce the coincidence peak and load shape at Veridian. The batteries will be scheduled to dispatch daily for no more than 4 hours in a 24-hour period. The batteries can be dispatched year-round at any time of the day and any day of the week.

Q57. Will the VPP pilot evaluate any other technologies at Veridian?

A57. No. The purpose of the VPP pilot is to evaluate the performance of a residential battery VPP only, to gain operational learnings specific to this technology. Customers who have other technologies, such as a smart thermostat, are eligible to enroll in other Company programs.

Q58. Are residential battery VPPs reflected in the Company's PCA?

A58. Yes. As described by Witness Hajj, the Company's PCA includes VPP resources. Specifically, residential battery VPP resources were selected in the Company's modeling as a cost-effective resource that can potentially provide capacity. As discussed earlier in my testimony, a VPP aggregates customer-sited resources to

balance electrical loads and provide utility-scale and utility-grade grid services. The Company's proposed Veridian VPP pilot is intended to provide operational experience and evaluate customer participation, battery availability, dispatch performance, and overall program cost-effectiveness. These learnings will help inform the design and implementation of a broader residential battery VPP offering ahead of the Company moving forward with deployment of the resource identified in the PCA.

Q59. Does the Company believe that a residential battery program could be beneficial to the utility and its customers?

A59. Yes. The Company has benchmarked residential battery DR programs to further the understanding of the potential utility and customer benefits of the program. Our research identified financial incentives as the most prevalent customer benefit. Whereas the Company could see benefits such as, but not limited to, capacity reduction, energy reduction, and ancillary services if the program is cost-effective. For specific benchmarking that the Company completed, please refer to the VPP pilot application in Case No. U-21653.

Part IV: Summary of DR Assumptions and Inputs

Q60. Could you briefly discuss the DR potential study that was completed on behalf of the State?

A60. Yes. Further discussed by Witness Kupser, the State of Michigan contracted with NV5 to complete a statewide potential study that looked at the statewide potential of Energy Waste Reduction, Demand Response and Electrification for Michigan's Upper Peninsula and Lower Peninsula (MISO and PJM areas). The study focused on a 20-year horizon, from 2026 to 2045 and evaluated the technical, achievable

and economic potential for DR programs across the residential, commercial and industrial sectors in Michigan. Each scenario modeled included the technical potential, maximum achievable potential, a mid scenario and a low scenario. Each scenario is defined in Figure 1.

Figure 1: Statewide DR Potential Study Scenario Definitions

- Technical Potential: the total reduction potential if every eligible customer were to participate in each option. This scenario is at the measure-level and does not consider interactions between opportunities.
- Maximum Achievable Potential: the total reduction potential if every opportunity provided incentives at the high-end of the range currently offered, resulting in a Utility Cost Test of near 1.0.
- Mid Scenario: the total reduction potential if incentives were set to 75% of the maximum achievable scenario.
- Low Scenario: the total reduction potential if incentives were set to 50% of the maximum achievable scenario

Q61. What opportunities did the statewide DR potential study evaluate?

A61. The statewide potential study evaluated nine opportunities that were made up of various measures. The opportunities included were Residential Direct Load Control, Residential Battery Storage, Residential Time-of-Use Rates, Residential Behavioral, C&I Auto DR/Fast DR, C&I Manual Curtailment, C&I Direct Load Control, C&I Battery Storage, and C&I Thermal Storage.

Q62. Could you describe each of the opportunities that were evaluated in the statewide DR potential study?

A62. Yes. I have provided a short description of each opportunity below.

- Residential Direct Load Control and C&I Direct Load Control were characterized as programs in which customers receive financial

Line No.

incentives in exchange for allowing the utility to directly control cooling and heating equipment, as well as residential pool pumps;

- Residential and C&I Battery Storage offerings were defined as programs that provide financial incentives to customers who permit the utility to dispatch installed battery systems during demand response events;
- Residential Time-of-Use Rates were described as rate structures that apply bill credits or elevated pricing during peak periods to encourage reductions in customer energy consumption; however, this option was not expected to yield incremental peak reductions due to the widespread adoption of time-of-use rates among Michigan residential customers and was not included in the DTE service area specific results;
- Residential Behavioral Demand Response encompassed programs that rely on targeted customer communications to prompt reductions in usage during peak events;
- C&I Auto DR/Fast DR referred to opportunities that leverage building automation and control systems to enable automated load reductions;
- C&I Manual Curtailment programs provide fixed bill credits or incentives based on the amount of load curtailed during events;
- C&I Thermal Storage was defined as an approach involving the installation of ice-based storage systems to shift load but was ultimately determined to be not cost-effective and therefore excluded from the study's potential estimates.

Q63. How did the statewide potential study determine if an opportunity was considered cost-effective?

A63. An opportunity was considered cost-effective if it had a Utility Cost Test (UCT) score greater than 1. All opportunities were considered cost-effective for the MISO area in the Lower Peninsula for all scenarios except C&I Thermal Storage[2].

Q64. How did the Company model DR based on the Statewide Potential Study?

A64. After completion of the Statewide Potential Study, NV5 completed a DTE Electric service area specific potential study[3] for the Company. I provided the IRP team with the specific program inputs as shown in Exhibit A-8.1 that were applicable to DTE Electric from the service-area specific results, specifically costs, where applicable, and capacity from the mid scenario.

Q65. Did you make any modifications to the DTE Electric service area specific results that were provided to the IRP team to be modeled?

A65. Yes. The first modification I made was to shift the start year from 2026 to 2028 to allow for the programs to be ramped up or to be implemented and ramped up if they were selected. The next step I took was to review the DTE Electric service area specific potential study capacity and cost data and compare it against the Company's capacity and cost data. Finally, I modified the potential study cost and capacity data as described below and shared the data with the IRP team to model.

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[2] In the maximum achievable scenario, residential direct load control had a UCT of 0.91, making it not cost-effective. Despite this, it is included in the potential because of how close the UCT is to 1.0; the significant existing participation and the levelized cost per kW of the program is still lower than MISO Zone 7 CONE.

[3] Volume-III-Demand-Response-Statewide-Potential-Study_20251017.pdf

Q66. What modifications did the Company make to the DTE service area specific demand response potential study?

A66. The Company made modifications to DTE Electric service area specific demand response results for C&I Battery Storage, C&I Direct Load Control, C&I Auto DR/Fast DR, C&I Manual Curtailment, Residential Behavioral DR, Residential Battery Storage, and Residential Load Control.

Q67. Could you describe the changes that were made to the C&I Battery Storage results?

A67. Yes. The Company modified the peak capacity reduction and cost assumptions provided in the potential study to reflect a more representative view of near-term C&I battery storage availability and expected demand response program participation within the Company's service area. Given the currently limited deployment of C&I battery storage and the absence of a well-established adoption trend, the Company did not rely on a standalone forecast of C&I battery adoption. As highlighted in the statewide potential study, battery adoption remains highly dependent on incentive levels and underlying value streams, with relatively low participation observed at modest upfront cost incentive levels and significant uncertainty regarding the timing and scale of broader market adoption. Consistent with this characterization of the market, the Company applied a proxy-based approach to estimate potential growth in available capacity. Specifically, the Company used the year-over-year growth characteristics observed in its residential battery forecast as a directional benchmark to approximate potential expansion in C&I battery availability. The resulting capacity estimates were then adjusted using a 50% market capture rate, consistent with participation levels observed in more

mature demand response programs, to estimate the portion of capacity that could reasonably be enrolled and dispatched. The Company estimated costs using the potential study's mid-case scenario incentive of $52/kW-year, applied the incentive to the estimated peak capacity for the respective years, and increased these costs to account for a DR financial incentive.

Q68. Could you describe the changes that were made to the C&I Direct Load Control results?

A68. Yes. The Company did not assume any growth beyond its current projections. C&I customers are eligible to enroll in the Company's direct load control DR programs, Smart Savers and CoolCurrents. In total, both programs have approximately 1,162 C&I customers enrolled, which is less than 1% of all C&I customers. A saturation rate of less than 1%, despite the program's existence for several years, led the Company to determine growth beyond its current projections were unlikely.

Q69. Could you describe the changes that were made to the C&I Auto DR/Fast DR results?

A69. Yes. The Company did not adjust the capacity from the DTE Electric service area specific potential study but did increase the costs to account for a DR financial incentive. The Company believes Auto DR enabling technology could enhance customers' ability to participate in demand response as MISO LMR reforms introduce requirements that add complexity to participation. The Company does not currently have an Auto DR specific offering and has not developed a forecast for growth in adoption of Auto DR enabling technology. In the absence of internal data pertaining to growth and costs, the Company adopted the potential study's

capacity and cost estimates, with the increase added to costs to account for a DR financial incentive.

Q70. Could you describe the changes that were made to the C&I Manual Curtailment DR results?

A70. Yes. Despite the DTE Electric service area specific potential study projecting additional growth potential within the C&I manual curtailment section, the Company did not assume any growth beyond its current projections. As previously mentioned in my testimony, the Company believes enrollment in legacy C&I DR tariffs is likely to decline. As a result, the Company has forecasted its capacity associated with the legacy C&I tariffs and riders to decrease from 371 MW for the MISO's 2026/27 Planning Resource Auction PRA summer season to 312 MW in 2029. Beginning with the 2028/29 planning year, accredited capacity will be calculated based on actual availability of the resource during MISO's tightest hours, which could also decrease the accredited capacity associated with the legacy tariffs. The DTE Electric service area specific potential study did not consider the effect that MISO LMR reforms would have on this customer segment when forecasting the C&I manual curtailment potential. Even with the incentive levels identified in the DR Potential Study, the Company does not believe that the increased incentive levels would outweigh the new LMR requirements, set forth by MISO and would encourage new enrollments in a C&I Manual Curtailment Program.

Q71. Could you describe the changes that were made to the Residential Behavioral DR results?

A71. Yes. The Company did not assume any potential for residential behavioral DR based on results from a pilot that was operated by the Company between 2021 and 2023. During this time, the Company conducted a Peak Time Savings (PTS) pilot in which customers received bill credits for reducing energy consumption during demand response events. Customers could reduce their energy consumption any way they saw fit, with no assistance from the Company. After the pilot concluded, the Company determined that it was not effective and terminated the PTS pilot at the end of 2023.

In addition, the Company did not consider any savings from a Critical Peak Pricing (CPP) program as this was a tariff (D1.8, Dynamic Peak Pricing) previously offered to customers. The Company has since closed the tariff to new customers as the Company observed low enrollment when the tariff was separated from the previously offered SmartCurrents program. The statewide study also acknowledged that there are significant barriers to enrollment in a CPP tariff.

Q72. Could you describe the changes that were made to the Residential Battery Storage results?

A72. Yes. The Company modified the peak capacity reduction and cost assumptions provided in the DTE Electric service area specific potential study to better align with the Company's load forecast and expectations for residential battery adoption within its service area as described in further detail by Witness Sirwaitis. The resulting capacity estimates were then adjusted using a 50% market capture rate, consistent with participation levels observed in more mature demand response programs, to estimate the portion of capacity that could reasonably be enrolled and

dispatched. The Company estimated costs by applying the potential study's mid-case scenario incentive of $52/kW-year, as well as estimated DERMS fees. These costs were then increased to account for a DR financial incentive.

Q73. Could you describe the changes that were made to the Residential Load Control results?

A73. Yes. The Company changed its current growth projections to capture incremental capacity and costs for the Company's existing load control programs (Smart Savers and CoolCurrents) to align the projections with potential study estimates. The Company implemented these changes until an estimated enrollment saturation for both programs was reached, after which incremental capacity was held constant and incremental costs were assumed to be $0. The Company estimated enrollment saturation for CoolCurrents by approximating the required timeline to bring all currently enrolled customers online and available for interruption. Estimated enrollment saturation for Smart Savers was provided by a third-party vendor that provides distributed energy resource management (DERMS) and virtual power plant services to utilities. The Company approximated costs by applying a $/MW estimate to the incremental capacity value for each year. This $/MW value was calculated by taking the sum of total estimated costs, including the DR financial incentive, and dividing it by the total estimated capacity assumed in the first year of the projections.

Q74. Did you provide any DR EV pilots to the IRP team to be modeled?

A74. No. The Company is conducting two DR EV pilots, Smart Charge and V2H. The Company decided not to provide either pilot to the IRP team to be modeled as

insights gathered by both pilots have not yet recognized sufficient value to model. This determination was supported in the Statewide DR Potential Study, (discussed earlier in my testimony) which stated many EV drivers are already charging during off-peak hours, resulting in little additional peak reduction from a managed charging program like Smart Charge.

Q75. Did the Company make any additional changes to the DTE service area specific demand response potential study?

A75. No.

Q76. What inputs and assumptions did you provide the IRP team to model for the existing Smart Savers and CoolCurrents Programs?

A76. For the 2026/2027 MISO Planning Year, the Company registered 76 MW for the Smart Savers Program and 74 MW for the CoolCurrents Program for the summer season, which were provided to the IRP team for modeling. The Smart Savers Program is projected to grow to 103 MW in 2029 by enrolling an additional 30,000 thermostats over the next three years. This level of annual enrollment aligns with the continued growth of the program since its inception in 2018.

The CoolCurrents Program is also forecasted to grow. The growth of the capacity associated with the program is a result of the aggressive equipment upgrades that will install an additional 20,000 Load Control Devices (LCDs) annually, totaling 60,000 LCDs over the three-year period post U-22046 test year. This would bring the total number of LCDs that are online and available for interruption to approximately 194,000. In addition, it was proposed in the Company's most recent

electric rate case (Case No. U-22046) to change the incentive mechanism for CoolCurrents customers who are available for interruption, to further encourage customers to ensure their equipment is up to date and functioning properly.

Q77. What inputs and assumptions did you provide the IRP team to model for the existing interruptible tariffs that the Company offers?

A77. As previously mentioned in my testimony, the Company offers six interruptible rates and riders (D3.3, D8, R1.1, R1.2, R10 and R12). Due to the LMR reforms that were filed by MISO to FERC, the Company believes enrollment on these legacy tariffs is likely to decline. As a result, the Company has forecasted its capacity associated with the legacy tariffs and riders to decrease from 371 MW for MISO's 2026/2027 Planning Resource Auction (PRA) summer season to 312 MW in 2028. In addition, beginning with the 2028/2029 planning year, accredited capacity will be calculated based on actual availability of the resource during MISO's tightest hours, which could also decrease the accredited capacity associated with the legacy tariffs.

The Company is working to add five additional MW beginning in 2027 and building to 20 MW by 2029. This will be achieved by designing a new commercial offering to target small commercial customers who can better abide by MISO's LMR reforms and testing requirements.

Q78. Did the Company assume any capacity from a competitive DR procurement for years 2027 - 2030 that was agreed upon in the Company's last IRP, Case No. U-21193?

A78. Yes. The Company intends to pursue the third solicitation and has made changes to the process in hopes of a successful procurement. The 100 MW was held flat for the IRP planning period as a placeholder for successful DR procurement solicitations, higher than forecasted customer enrollment into current programs, and/or new DR programs that are brought online post 2030.

Q79. Could you describe the actions that the Company took attempting to procure capacity through a competitive procurement process?

A79. Yes. The Company retained Guidehouse, Inc. (Guidehouse) to develop a Request for Proposal (RFP) and issued the first RFP on June 26, 2024. The Company only received one intent to bid response and received zero bids from the 14 aggregators invited to bid. The second solicitation for 25 MW beginning with the 2026/27 MISO Planning year was issued on April 10, 2025. The Company expanded the bid to invite 17 aggregators, and again, received zero bids.

Q80. What feedback has the Company received from aggregators as to why bids have not been submitted in response to the RFP?

A80. The Company has only received feedback from one of the aggregators regarding why they chose not to respond to the RFP despite the Company's effort to better understand why aggregators are not participating. After the second solicitation the Company received three suggestions from one aggregator on potential ways to increase aggregator participation:

1. Remove the 1 MW per site minimum capacity requirement.

2. Increase the incentive for new customers to participate in the program. Specifically, offering new customers the greater of $150,000/MW-year or the MISO market clearing price for five years.

3. The Company should act as the MISO market participant, with the vendor responsible for submitting all necessary site-specific test materials to DTE.

Q81. Does the Company have any response to these suggestions?

A81. While the Company appreciates the time the aggregator took to provide feedback, the Company believes incorporating the suggested feedback into the next RFP would present the following challenges. First, the Company cannot remove the 1 MW limitation, as this limitation is a State of Michigan DR aggregation requirement for bundled customers that stems from the Order in Case No. U-21099. Second, paying a customer over $150,000/MW-year is greater than MISO's PY 2026/2027 Cost of New Entry (CONE) value of $137,510/MW-year and significantly greater than the Company's Rider 12 tariff which pays customers approximately $25,000/MW-year in exchange for load curtailment, making it not cost-effective and resulting in ratepayers overpaying for a capacity resource.

In response to the third suggestion of DTE acting as the MISO market participant for the aggregator, the Company believes this participation model would add unnecessary risks to the Company and its customers. In this model, the Company would be responsible for any risk should the aggregator not fulfill its capacity delivery obligations. Financial penalties for not fulfilling capacity delivery obligations have been increased by MISO and could result in significant financial loss, as well as loss of accreditation for future offerings by the Company. A

participation model in which the aggregator is the market participant eliminates the financial risk to the Company and its customers, as any penalties for underperformance would be the responsibility of the aggregator.

Q82. Is the Company exploring changes to the third solicitation to receive bids to procure capacity?

A82. Yes. Prior to launching the third and final solicitation RFP, the Company conducted a Request for Information (RFI) to increase awareness of the opportunity for organizations who might be interested in bidding, as well as hopes of learning from potential bidders what they would like to see in the RFP. In the RFI, organizations were asked to describe anticipated challenges with meeting the proposed RFP requirements as well as provide recommended amendments to the requirements that would increase the appeal of the RFP. Upon review of the RFI, the Company will modify the RFP as appropriate. The Company also explored a partnership with Piclo, a Distributed Energy Resource (DER) marketplace, but ultimately decided against the partnership due to the costs and uncertainty around what the additional benefits (if any) would be observed.

Q83. In total, how many MW of DR does DTE forecast to have available in 2029?

A83. As seen on Exhibit A-8, the Company forecasts to have a DR portfolio totaling 638 MW (ICAP) of demand response in the Summer 2029.

Q84. Can you summarize all the inputs and assumptions that you provided to the IRP team to be modeled?

A84. Yes. I provided the following inputs and assumptions to the IRP team as shown in Exhibit A-8.

1. Forecasted the Company's Direct Load Control Programs (CoolCurrents and Smart Savers) to grow to 206 MW in 2029.
2. Forecasted the Company's DR Tariffs (D3.3, D8, R1.1, R1.2 and R10) to decrease to 312 MW in 2029.
3. Forecasted a new program(s) to add an additional 20 MW to the DR portfolio by 2029.
4. Assumed no additional potential for the C&I Manual Curtailment measure for the duration of the potential study period due to already being a large part of the Company's portfolio.
5. Assumed 100 MW procured for the next three planning years through a successful DR procurement solicitation or new DR programs that are brought online.

Part V: DR IN THE PROPOSED COURSE OF ACTION

Q85. How does demand response support the Company's overall IRP strategy and proposed course of action?

A85. Demand response is an important component of the Company's PCA. As described by Witness Hajj, the PCA is designed to maintain reliability, support affordability, advance the clean energy transition, and meet applicable statutory requirements through a diverse portfolio of supply-side and demand-side resources. Demand response contributes to accredited capacity that supports the Company's resource adequacy requirements and helps shift demand during periods of system need. In addition, demand response complements other resources within the PCA by helping

manage overall system costs. Accordingly, the Company continues to maintain and expand demand response resources where supported by customer participation, operational performance, and cost-effectiveness. As discussed earlier in my testimony, this includes growth in existing programs and continued evaluation of virtual power plant and other demand response opportunities that may provide additional capacity in the future.

Q86. What incremental DR resources were included in the PCA?

A86. The PCA includes approximately 73 MW of VPPs, modeled as residential battery and C&I battery programs based on the Company's previously discussed potential study modifications. Per exhibit A-8.1 lines 2 and 7 the residential program begins with 15 MW in 2028 and grows to approximately 70 MW in 2046. The C&I program begins with approximately 1 MW in 2028 and grows to approximately 3 MW in 2046. The total cost of the residential program over the study duration was established using the Demand Response residential battery cost assumptions discussed previously in my testimony and is estimated at approximately $65 million. The total cost of the C&I program over the IRP planning period was established using the Demand Response C&I battery cost assumptions discussed previously in my testimony and is estimated at approximately $2 million. The costs are projected to be made up mostly of operations and maintenance (O&M), including incentives and DERMS fees.

Q87. How does the Company plan to grow the residential and C&I battery program to the forecasted levels?

A87. The Company will use the learnings from the Veridian VPP pilot, which is a residential battery VPP, to grow the program. The program utilizes a performance-based incentive of $52/kW-year with no upfront incentive. The program will target customers who already own a residential or C&I battery within the Company's service territory for enrollment.

Part VI: DR CAPITAL COSTS FOR PRE-APPROVAL

Q88. What capital costs is the Company requesting the Commission preapprove for CoolCurrents as an existing DR resource included in the proposed resource plan?

A88. The Company is requesting pre-approval of $21 million of capital expenditures over the three-year period from 2028-2030 to purchase new load-control devices and replace obsolete or unavailable CoolCurrents load-control devices with the new devices. Doing so will increase the amount of enrolled capacity that is online, dispatchable, and available for interruption. CoolCurrents is an existing DR capacity resource included in the IRP's starting point resource portfolio. The requested investment is necessary to maintain and achieve the CoolCurrents capacity reflected in the Company's IRP assumptions and proposed resource plan. Exhibit A-8.2 provides the annual capital costs for which the Company requests preapproval.

The Company is not requesting cost preapproval in this proceeding for O&M expenses associated with CoolCurrents or the remainder of its DR portfolio. Those expenses will be addressed through the applicable ratemaking processes. In addition to the capital expenditures described above, the Company currently

projects approximately $30.7 million of O&M expenditures from 2028 through 2030 for the continued operation and development of its DR portfolio. These projected O&M expenditures include costs associated with CoolCurrents, Smart Savers, Smart Charge, residential VPP program, and other DR pilots and programs. The Company provides this information to present the projected costs of its DR portfolio, but it does not request preapproval of those O&M expenditures under MCL 460.6t(11).

Q89. Was CoolCurrents selected as an incremental resource through the capacity expansion optimization?

A89. No. CoolCurrents is an existing DR resource reflected in the starting point resource portfolio used in the IRP modeling. As Witness Manning explains, the IRP model evaluates the incremental resources needed after accounting for the starting point planning resources. The proposed CoolCurrents investment is therefore not presented as a newly selected optimization resource. Rather, it is an investment necessary to maintain and achieve the capacity contribution from an existing resource specifically included in the Company's PCA.

Q90. How does the proposed investment affect the capacity available from CoolCurrents?

A90. The Company currently has enrolled customers whose load-control devices are obsolete or no longer available for interruption. Replacing those devices increases the quantity of enrolled load that can be reliably dispatched and counted toward the Company's projected DR capacity. The investment is forecast to support an increase in CoolCurrents capacity by 30MW while also sustaining capacity that

could become unavailable as existing devices age or fail. Without continued investment, the Company will be unable to maintain or increase CoolCurrents capacity to forecasted levels.

Q91. Can you elaborate on the pre-approval of capital that is being requested for the CoolCurrents Program?

A91. Yes. As previously mentioned, the Company plans to continue to grow the CoolCurrents Program. To do so, the Company will need to continue to aggressively replace the approximately 82,000 obsolete radio control units (RCUs). The Company plans to purchase, update and install an additional 20,000 LCDs annually after the rate case test year, as well as investigate 5,000 offline LCDs annually, totaling approximately 60,000 LCDs over the three-year period, bringing the total of LCDs that could be online and available for interruption to approximately 194,000. This total also includes the planned 15,000 LCD installations as discussed by Witness Leuker in case no. U-22046 for the test year in that instant case. Following approval of the requested capital for the CoolCurrents program, the Company is planning to administer contracts to vendors, develop a strategic installation plan, communicate LCD installations to customers, and begin updating and installing LCDs to achieve the planned 20,000 annual installations.

Furthermore, the Company has upgraded the device management platform used to monitor and provide feedback on device operational statuses. These upgraded capabilities provide the Company with improved visibility into online and offline devices and subsequent replacement needs. The Company has also established a

practical path to achieving the targeted installation quantities through a refined customer agreement approach as well as engagement with contractors and internal field service personnel.

Q92. Does this complete your direct testimony?

A92. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARGARET E. GUILLAUMIN

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MARGARET E GUILLAUMIN

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Q1. What is your name, business address and by whom are you employed?

A1. My name is Margaret E. Guillaumin (she/her/hers). My business address is One Energy Plaza, Detroit MI, 48226. I am employed by DTE Electric Company (DTE Electric or Company) as Plant Director in the Energy Supply organization.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. My formal education consists of a Bachelor of Science degree in Chemical Engineering from Michigan Technological University. I have also completed several Company sponsored courses and have attended various seminars to further my professional development with DTE Electric.

Q4. What is your professional experience?

A4. I began my employment with DTE Electric in July 2003 in the engineering department at River Rouge Power Plant. Throughout my career with DTE Electric I have received various promotions with increasing levels of responsibility. These positions included several engineering roles at the St. Clair Power Plant beginning in November 2003, Supervisor of Chemical Engineering for DTE Electric's fossil power plants in 2010, Manager of Laboratory and Field Support in 2012, Fuel Supply Manager at St. Clair Power Plant in 2014, and St. Clair Power Plant Maintenance Manager in 2016. In October 2017, I was promoted to Plant Manager, Greenwood Energy Center, responsible for all day-to-day operation,

maintenance, and engineering for the facility. In April 2019, my role was expanded to include DTE Electric's natural gas and fuel oil Peakers, as well as DTE Electric's interest in the Ludington Pumped Storage facility. In April 2022, I was appointed Plant Manager, Blue Water Energy Center (BWEC), where I was responsible for transitioning the newly constructed facility through final commissioning activities to commercial operation. Following the commercial operation date, I was responsible for the day-to-day operation, maintenance, and engineering of the facility. In April 2023, I was promoted to Plant Director, Operations Performance. In this role, my responsibilities included periodic outage planning and execution for DTE Electric's fossil fuel power plants, strategic planning and long-term generation strategy, asset maintenance planning, and oversight of the St. Clair, Trenton Channel, and River Rouge Power Plants during decommissioning, as well as responsibilities for approving capital projects as a voting member of the Capital Governance Board.

Q5. What are your current duties and responsibilities?

A5. In March 2024, I was appointed to the role of Plant Director, Energy Supply. In addition to maintaining my responsibilities over the decommissioning sites, my responsibilities transitioned to include oversight of natural gas and peaker generating units in the DTE Electric's fleet as well as DTE Electric's interest in the Ludington Pumped Storage facility.

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Q6. Have you previously provided testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in the following cases:

U-21534	DTE Electric 2024 Rate Case
U-21860	DTE Electric 2025 Rate Case
U-22046	DTE Electric 2026 Rate Case

Line No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to provide details regarding the DTE Electric fossil-fueled, nuclear, and energy storage assets in support of the 2026 Integrated Resource Plan (IRP) including:

- The location, size, age, fuel, environmental controls, and other general characteristics of the existing dispatchable electric generating assets owned and operated by DTE Electric
- The Operation and Maintenance (O&M) expenses and capital expenditures planned for Monroe Power Plant and Greenwood Energy Center under various retirement sensitivities analyzed in this IRP that are discussed by Witness Manning
- The O&M expenses and capital expenditures planned for peaker power plants under various retirement sensitivities analyzed in this IRP that are discussed by Witness Pratt

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-9	O&M and Capital Projected Expenditures – Monroe Power Plant
A-9.1	O&M and Capital Projected Expenditures – Greenwood Energy Center
A-9.2	O&M and Capital Projected Expenditures – Peaker Power Plants

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Q10. How is your testimony organized?

A10. My testimony consists of the following three parts:

Part I	Characteristics of Dispatchable Generation Resources
Part II	Monroe Power Plant and Greenwood Energy Center Projected O&M Expenses and Capital Expenditures
Part III	Peaker Projected O&M Expenses and Capital Expenditures

PART I – CHARACTERISTICS OF DISPATCHABLE GENERATION RESOURCES

Q11. Can you describe the existing DTE Electric fossil-fueled, nuclear, battery energy storage systems (BESSs), and pumped storage hydro generating fleet?

A11. DTE Electric currently owns and operates two coal-fired steam power plants (Monroe and co-owner of Belle River Unit 2), one natural gas-fired combined cycle power plant (Blue Water Energy Center), two natural gas-fired steam power plants (Greenwood and co-owner of Belle River Unit 1), one nuclear power plant (Fermi 2[1]), one BESS (Slocum), is a co-owner of six pumped storage hydraulic power plant units (Ludington), and is also the owner of one natural gas-fired combined heat and power plant (Dearborn CHP) and 68 natural gas-fired and oil-fired peaker units in operation in the lower peninsula of Michigan.

Table 1 contains a summary of the characteristics of the existing fossil-fueled, nuclear, BESS, and pumped storage generating units in operation.

[1] Witness Pratt describes DTE Electric's long-term strategy in more detail, including Fermi 2.

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Table 1 Current Generating Units (Non-Renewable) as of 1/1/2026

Plant	Location	Commercial Operation Date	Projected Retirement	Summer Capacity (Net MW)	Primary Fuel	Emissions Control	Co-Owned?
Belle River	East China Twp, China Twp	1984-5	2039	1,270 (1,034 DTE Electric, 81.39%)	Natural Gas, Coal	Low NOx[1] burners, OFA[2], ESP[3], DSI[4], ACI[5]	Michigan Public Power Agency, 18.61%
Blue Water Energy Center	East China Twp	2022	Beyond Study Period	1,127	Natural Gas	Multi-pollutant catalyst, SCR[6], low NOx[1] turbines	No
Fermi 2	Frenchtown Twp	1988	Beyond Study Period	1,141	Nuclear	Non-emitting	No
Greenwood	Avoca Twp	1979	Beyond Study Period	785	Natural Gas	Low NOx[1] burners, OFA[2]	No
Ludington Pumped Storage	Ludington	1973	Beyond Study Period	1,122 (DTE Electric, 49%)	Hydro	Non-emitting	Consumers Energy, 51%
Monroe	Monroe	1971-4	Monroe 3-4 (2028) Monroe 1-2 (2032)	3,066	Coal	Low NOx[1] burners, OFA[2], ESP[3], SCR[6], FGD[7]	No
Peaker fleet	Various	Various	Superior 11-1 - 11-4 (2032) All Others Beyond Study Period	1,928	Oil, Natural Gas	Low NOx[1] turbines, oxidation catalysts	No
Dearborn CHP	Dearborn	2019	Beyond Study Period	34	Natural Gas	Low NOx[1] turbines	No
Slocum BESS	Trenton	2025	Beyond Study Period	14 (56 MWh)	Lithium-Ion	Non-emitting	No

Acronyms: 1 – Nitrogen Oxide; 2 – Over Fire Air; 3 – Electrostatic Precipitators; 4 – Dry Sorbent Injection; 5 – Activated Carbon Injection; 6 – Selective Catalytic Reduction; 7 – Flue Gas Desulfurization

Q12. How has the Company modified its generation fleet since 2014?

A12. Between 2014 and 2026, the Company retired or converted 3,333 MW of coal-fired capacity by completing the retirements of Harbor Beach (103 MW), River Rouge (523 MW), St. Clair (1,367 MW), and Trenton Channel Power Plant (705

MW) and the conversion of Belle River Unit 1 from coal-fired to natural gas-fired operation (635 MW). This substantially reduces the Company's reliance on coal-fired generation and leaves only two Company coal-fired power plants in operation – Belle River Unit 2 (635 MW) and Monroe Power Plant (3,066 MW).

Q13. What are the Company's planned retirement dates for the remaining operating coal-fired power plants?

A13. The Company's planned coal-fired unit retirements in the Proposed Course of Action (PCA) in this filing are consistent with the Case No. U-21193 Order dated July 26, 2023, in the Company's 2022 IRP. This includes converting Belle River Unit 2 from coal-fired to natural gas-fired operation by the end of 2026, retirement of Monroe Units 3 and 4 by the end of 2028, and retirement of Monroe Units 1 and 2 by the end of 2032. By 2033, the Company will have retired over 7,000 MW of coal-fired capacity, which is inclusive of all its coal-fired power plants, over the course of twenty years.

Q14. How will the changes in the Company's generation fleet, including the planned retirement of Monroe Power Plant, impact the Company's employees?

A14. Through the transition of its electric generating fleet, DTE Electric has managed changes in workforce needs in an equitable manner that supports employees while maintaining institutional knowledge and operational expertise at the Company. For employees, this means creating opportunities to continue their careers at DTE Energy. As with other plant retirements, the Company intends to maintain its no-layoff commitment and will continue working with represented and non-

represented employees and union leadership to support workforce transitions. These efforts include employee redeployment to other areas of the business and, where appropriate, retraining opportunities to facilitate successful transitions.

PART II –MONROE POWER PLANT AND GREENWOOD ENERGY CENTER PROJECTED O&M EXPENSES AND CAPITAL EXPENDITURES

Q15. Can you describe the information shown in Exhibits A-9 and A-9.1?

A15. Exhibits A-9 and A-9.1 show the forecasted annual O&M and capital expenditures planned for the Monroe Power Plant and Greenwood Energy Center, respectively, under the retirement sensitivities analyzed in this case as described by Witness Manning. The exhibits contain forecasts for base plant O&M expense, major maintenance O&M expense, and major maintenance capital expenditures, balance of plant capital expenditures, and major environmental capital expenditures for the relevant years of the analysis.

Q16. How were the base O&M expenses in Exhibits A-9 and A-9.1 developed?

A16. Base O&M values were based on data from the most recent full year of available actuals (2025), which served as the starting point for the forecasts. The 2025 historical values were then adjusted for known and measurable changes to represent the future routine annual O&M required to operate and maintain the plants. These values do not include major maintenance expenditures that occur less frequently. Values were also escalated based on the Unadjusted Consumer Price Index (CPI). The use of this inflation mechanism is consistent with the IRP modeling process and is described by Witness Busse in his testimony.

Line No.

Q17. How is the Monroe Power Plant base O&M expense forecast modified when staggered unit retirements are considered?

A17. In sensitivities in which half of the units at a plant retire in a given year, the Company assumes that a 30% reduction in the base O&M retains sufficient funding to support the continued operation of the remaining units in future years. The reason base O&M costs are not reduced by 50% when half the plant retires is because there are common costs that must still be supported even though there are fewer operating units at the plant. These continuing common expenses include fuel system operations, environmental controls and monitoring requirements, and plant management and supervision. This general approach is utilized to forecast Monroe Power Plant base O&M when staggered unit retirements are considered.

Q18. Does O&M increase in a power plant's final year of operation?

A18. Yes. During the final year of operation, equipment replacements are expensed to O&M and not capitalized per the Company's accounting policy for equipment that has a useful life of less than a year. For the purposes of the Company's projections in the instant case, there is an increase in O&M expense in the final year of operation of a Company power plant that is equivalent to the reduction in balance of plant capital.

Q19. How were the major maintenance O&M expense and capital expenditure forecasts for Exhibits A-9 and A-9.1 developed?

A19. The major maintenance O&M expense and capital expenditure forecasts were developed based on a long-term maintenance schedule that considers both the timing and duration of future planned major maintenance outages for each unit,

and the retirement of the respective units. Future major maintenance outages vary in cost and duration depending on the forecasted scope of needed repairs. The maintenance O&M and capital cost forecasts were escalated for inflation based on the CPI as previously discussed.

Q20. Can you explain the balance of plant capital expenditures forecasts included in Exhibits A-9 and A-9.1?

A20. The balance of plant capital expenditure forecasts in Exhibits A-9 and A-9.1 were based on anticipated levels of plant capital expenditures for common systems, routine replacements, and replacements associated with major non-outage maintenance projects. These capital expenditure forecasts were also escalated based on the CPI inflation previously discussed.

Q21. Can you describe the major environmental capital expenditure forecasts for Monroe Power Plant contained in Exhibit A-9?

A21. Exhibit A-9 includes projects to comply with Steam Electric Power Generating Effluent Limitation Guidelines (ELG) and Coal Combustion Residual (CCR) Rules for Monroe Power Plant. Witness Marietta describes these rules, regulations, and compliance dates in detail, as well as their current evolving status.

Q22. Can you summarize the Monroe-related major environmental capital expenditure forecasts projected in the Company's PCA?

A22. The Monroe-related major environmental capital expenditures projected in the Company's PCA are summarized in Table 2:

Line No.

Table 2 Monroe-Related Major Environmental Capital Expenditures (2027-2046) ($ million)

Regulation	Monroe Power Plant
Effluent Limitation Guidelines (ELG)	$7 [1]
Coal Combustion Residual (CCR)	$474 [2]

1. Flue Gas Desulfurization (FGD) Wastewater ($7 million).

2. Fly Ash Basin Closure ($249 million), Legacy CCR ($174 million) and Sibley Quarry Closure ($51 million).

PART III – PEAKER PROJECTED O&M EXPENSES AND CAPITAL EXPENDITURES

Q23. Can you describe the information shown in Exhibit A-9.2?

A23. Exhibit A-9.2 shows the forecasted annual O&M and capital expenditures planned for peaker power plants through 2046. This information is used in retirement analysis described by Witness Pratt. The exhibit contains forecasts for ongoing O&M expense, ongoing capital expenditures, major maintenance O&M expense, and major maintenance capital expenditures.

Q24. How were the ongoing O&M expenses and capital expenditures in Exhibit A-9.2 developed?

A24. The ongoing O&M and capital values are engineering estimates of the annual maintenance requirements covering basic inspections, testing, and repairs. These values do not include major maintenance expenditures that occur less frequently. Values were also escalated based on the CPI. The use of this inflation mechanism

is consistent with the IRP modeling process and is described by Witness Busse in his testimony.

Q25. How were the overhaul O&M expense and capital expenditure forecasts for Exhibit A-9.2 developed?

A25. Major maintenance intervals for peakers are determined by cumulative run hours and the number of startup sequences experienced over time. The overhaul O&M expense and capital expenditure forecasts were developed based on long-term maintenance plans and engineering estimates of the major maintenance requirements for each unit. For combustion turbine peakers, these requirements include combustion overhauls, hot gas path overhauls, and major overhauls. For diesel generators operating on fuel oil, the forecasts reflect engine and generator overhauls. Additional capital expenditures are included for various other planned work, such as controls system upgrades and transformer replacements. The timing of major maintenance outages across the peaker fleet is staggered to prevent the units from undergoing major maintenance simultaneously, thereby supporting system reliability and efficient management of outage resources. The overhaul O&M and capital cost forecasts were escalated for inflation based on the CPI as previously discussed.

Q26. Does this conclude your testimony?

A26. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

DAVID SWIECH

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF DAVID SWIECH

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is David Swiech. My position is Director of Fuel Supply. I am employed by DTE Electric Company (DTE Electric or Company). My business address is One Energy Plaza, Detroit, Michigan 48226.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Mechanical Engineering from the University of Michigan in 2001 and a Master of Business Administration degree from the University of Michigan's Stephen M. Ross School of Business in 2010.

Q4. What is your professional experience?

A4. Prior to joining DTE Energy, I worked for American Mitsuba Corporation from 2002-2005, and ASMO Detroit, Inc from 2005-2010. During this time, I was responsible for the design and development of small motor applications in the automotive industry.

I have been employed by DTE Energy since 2010. From 2010 through 2012, I held various positions within the Controller's Organization, including budgeting and forecasting for DTE Gas Company (DTE Gas), corporate capital planning and analysis, and financial support for DTE Electric's Renewable Energy Program. In 2013, I joined DTE Gas's Midstream Services group as a Marketing Program Manager. In this role, I marketed and sold natural gas storage and transportation

services to off-system customers. In late 2013, I was promoted to manage the optimization of DTE Gas's storage and transmission assets and performed that function through early 2016.

In 2016, I transferred to the Fuel Supply department of DTE Electric as Manager, Planning and Procurement. In that role, I had the responsibility of managing the Company's purchases of fossil fuels and associated transportation used for electric generation. I also managed the Company's preparation of budgets and forecasts regarding all fossil fuels used for electric generation. In 2021, I transferred to the Generation Optimization department as Manager of Contracts and Compliance, where I was responsible for negotiation and administration of contracts, settlement of wholesale power market transactions, and ensuring compliance with the North American Electric Reliability Corporation (NERC) standards. In August 2022, I was promoted to my current role of Director of Fuel Supply.

Q5. What are your current duties and responsibilities?

A5. As Director of Fuel Supply at DTE Electric, I am responsible for providing oversight and strategic direction to the Fuel Supply department. The department is responsible for the planning and procurement of all fuels and associated transportation used for electric generation. It is also responsible for fuel delivery logistics and management of the Company's railcar fleet.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

Line No.

A6. Yes, I sponsored testimony in the following cases:

U-17920	DTE Electric's 2016 PSCR Plan
U-18091	DTE Electric's 2017 PURPA Avoided Cost
U-18419	DTE Electric's Certificates of Necessity
U-21195	DTE Electric's Arbor Hills Amended Agreement
U-21260	DTE Electric's 2023 PSCR Reconciliation
U-21426	DTE Electric's 2024 PSCR Reconciliation
U-21594	DTE Electric's 2025 PSCR Plan
U-21595	DTE Electric's 2025 PSCR Reconciliation
U-21875	DTE Electric's 2026 PSCR Plan

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my direct testimony is to:

- Describe the Company's current and projected fuel supply arrangements and costs associated with the Company's existing and planned generating facilities;
- Describe and support the fuel price forecasts used in the Company's Integrated Resource Plan (IRP) process;
- Describe the projected fuel costs associated with potential supply resource options for DTE Electric's resource plan; and
- Describe the fuel type, supply, and projected costs associated with the Company's proposed carbon capture and storage ready (CCS-ready) combined cycle gas turbine (CCGT) projects.

Q8. Did you provide inputs to the group responsible for conducting the IRP modeling process?

A8. Yes. As further described by Witness Manning and discussed later in my testimony, I provided a five-year delivered fuel price forecast for the various fuels consumed at the Company's existing generating facilities. In addition, I estimated the fuel costs associated with potential supply resources modeled as alternatives in the IRP optimization modeling as discussed by Witness Manning.

Q9. Are you sponsoring any exhibits in the proceeding?

A9. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-10	Henry Hub Price Forecast Accuracy – EIA Annual Energy Outlook 2009 - 2024
A-10.1	Henry Hub Price Forecast Accuracy – Market Futures 2009 – 2024
A-10.2	Henry Hub Price Forecast Accuracy – Siemens vs EIA AEO 2014 - 2024

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony is organized into the following four parts:

Part I	Fuel Supply to DTE Electric's Existing Generating Facilities
Part II	Fuel Price Forecasts Used in the IRP Process
Part III	Fuel Forecasts for Potential Supply Resources Analyzed in the IRP Modeling Process
Part IV	Fuel Supply Plan and Forecasts for DTE Electric's Proposed Projects

PART I: FUEL SUPPLY TO DTE ELECTRIC'S EXISTING GENERATING FACILITIES

Q12. Can you describe the Company's existing generating facilities?

A12. As described by Witness Guillaumin, DTE Electric has a diverse fleet of existing generating facilities powered by various fuel sources. While the Company has

reduced its reliance on coal-fired generation, DTE Electric currently operates coal-fired generators at two sites – the Monroe and Belle River Power Plants. However, the Company converted one of two units at Belle River Power Plant from coal-fired to natural gas-fired operation in 2025 and plans to convert the remaining Belle River unit to natural gas-fired operation by the end of 2026. The Company also has oil-fired generating capability at its Monroe and Belle River Power Plants along with several oil-fueled peaking units. Furthermore, DTE Electric has natural gas-fired generating capability at the Blue Water Energy Center (BWEC), Greenwood Energy Center, Greenwood Peakers, Renaissance, Dean, Belle River Power Plant, Belle River Peakers, Delray, Dearborn CHP, Hancock, Northeast, and St. Clair Peakers sites. Finally, DTE Electric has nuclear generation at the Fermi 2 Nuclear Power Plant.

Q13. What types of fuels are consumed at the Company's Monroe coal-fired power plant?

A13. The Company's coal-fired power plant, Monroe Power Plant, consumes a combination of Low Sulfur Western (LSW) and High Sulfur Eastern (HSE) coal. LSW accounted for approximately 88% of the Company's coal consumption in 2025, due to its favorable pricing and emissions when compared to HSE coal. Although LSW is historically lower in cost on a per ton delivered basis, the Company's Monroe Power Plant can blend HSE and LSW coal to utilize the higher heat content of HSE coal to maximize generation production. In addition to coal, petroleum coke (petcoke), a byproduct of the petroleum refinement process, is consumed at Monroe Power Plant. Petcoke is an economic fuel that provides higher heat content when compared to coal.

Q14. How does the Company procure fuel supply for its existing coal-fired generating facilities?

A14. To maintain reliable supply, reduce exposure to spot prices, and reduce price volatility for our customers, at least three-quarters of DTE Electric's total coal supply requirement is purchased on a forward basis at fixed prices. Monroe Power Plant consumes a combination of LSW from Wyoming, HSE from the Northern Appalachia region, and petcoke. All three fuels can be delivered via rail and vessel, although petcoke is delivered primarily via truck. With the cessation of transshipment operations at DTE Electric's subsidiary Midwest Energy Resources Co. (MERC) in 2026, DTE Electric intends to utilize various Lake Erie docks for transshipment of coal from rail to vessel. Coal deliveries for Belle River Power Plant have been completed, and the plant will utilize its coal on site until it ceases coal consumption by the end of 2026.

Q15. How does the Company procure fuel supply for its existing oil-fired generating facilities?

A15. The Company uses diesel fuel oil (fuel oil) for startup and over-fire capabilities at its coal-fired generating units. Diesel fuel oil is also used at the Company's diesel peaking generator units. Fuel oil is held in inventory and ordered as needed and delivered via truck to the respective site. Fuel oil supply and transportation pricing is market index based with a markup applied by the supplier.

Q16. How does the Company procure fuel supply for its existing natural gas-fired generating facilities?

A16. Depending on the location, natural gas and its transportation are procured directly from supply and transportation providers, via third-party marketers, or from local distribution companies (LDCs). A brief summary of how natural gas is supplied to each of the Company's gas-fired generators is provided below.

BWEC

The Company's fuel supply plan for baseload natural gas generation, including BWEC, relies on multiple pipeline interconnects, firm transportation from liquid gas purchase locations, firm gas storage, and forward fixed-price purchases. Together, these elements support reliable and affordable gas supply while limiting exposure to volatile gas markets. DTE Electric purchases gas year-round with a combination of short-term and long-term purchases. To reduce exposure to spot prices and reduce price volatility for its customers, approximately two-thirds of BWEC's supply is purchased on a forward basis at fixed prices. The Company has firm transportation agreements with Vector Pipeline and Enbridge for access to the Dawn hub and with DTE Gas Company and NEXUS Gas Transmission for access to the Utica Marcellus region, providing redundancy in transportation service from diverse locations of gas supply. DTE Electric has firm storage and balancing agreements with Enbridge and Washington 10 Storage Corporation, which include approximately 6.5 billion cubic feet (Bcf) of storage capacity. These contracts allow for multiple ways to serve BWEC reliably while minimizing costs to its power supply cost recovery (PSCR) customers.

Greenwood Energy Center and Greenwood Peakers

Greenwood gas supply and transportation is provided by a third-party gas marketer. The gas is delivered to the ANR Pipeline interconnect with the lateral pipeline owned and operated by SEMCO Pipeline Company. DTE Electric has a firm gas transportation agreement with SEMCO to transport gas from the ANR Pipeline interconnect to the plant. The Company pays for gas based on prices at the Dawn hub, plus applicable transportation costs.

Renaissance

DTE Electric purchases gas at MichCon Citygate from a third-party gas marketer. The Company has a firm gas transportation agreement with DTE Gas to transport that gas on its system to the plant. The Company's agreement with DTE Gas includes approximately 0.9 Bcf of firm storage capacity.

Dean

DTE Electric purchases gas at MichCon Citygate and Dawn from a third-party gas marketer. The Company has a firm transportation agreement with DTE Gas to transport that gas to the plant. DTE Electric also has an agreement with DTE Gas for balancing services, which includes approximately 0.3 Bcf of storage capacity.

Belle River Power Plant and Belle River Peakers

DTE Electric purchases gas from third-party marketers at the China Township point on the Great Lakes Gas Transmission pipeline. The Company has a firm transportation agreement with SEMCO to transport gas from Great Lakes Gas Transmission to the power plant and peakers.

Delray and Dearborn CHP

DTE Electric purchases gas at MichCon Citygate from third-party gas marketers. The Company has a firm transportation agreement with DTE Gas to transport that gas to the plants. DTE Electric's transportation agreements with DTE Gas include approximately 0.3 Bcf of firm storage capacity.

Hancock and Northeast

DTE Electric purchases delivered natural gas from Consumers Energy under LDC tariff service.

St. Clair Peakers

DTE Electric purchases delivered natural gas from SEMCO Energy under LDC tariff service.

Q17. How does the Company procure fuel supply for its existing nuclear generating facility?

A17. Natural uranium used for generation at Fermi 2 must go through four basic steps prior to delivery to the plant – mining and milling, conversion, enrichment, and fabrication.

- Natural uranium (U3O8 concentrate) is obtained from the exploration, mining, and milling of uranium ore. U3O8 is the form of natural uranium most commonly traded.

- Conversion is the process whereby the U3O8 is purified and chemically converted into uranium hexafluoride (UF6). UF6 is a gaseous compound of uranium and fluorine used as feed in the enrichment process.
- During enrichment, natural uranium containing approximately 0.7% of the fissile isotope U235, is enriched to have an average U235 content of 3% to less than 5%.
- In fabrication, the enriched UF6 is chemically converted to uranium dioxide powder (UO2), pressed and sintered into hard ceramic fuel pellets, loaded into long, narrow zirconium alloy tubes, and assembled into fuel bundles. At Fermi 2, approximately one-third of the fuel bundles are replaced during each refuel outage.

The Company secures the future fuel requirements years before each refuel outage through diverse uranium origins and suppliers, supporting fuel supply reliability and price stability. In addition, the Company secures long-term arrangements for conversion, enrichment, and fabrication services well in advance of refuel outages to ensure these services are available. The Company calls on these services in preparation for each refuel outage (which takes place approximately every 24 months), and the fuel bundles are delivered to Fermi 2 in advance of the outage.

PART II: FUEL PRICE FORECASTS USED IN THE IRP PROCESS

Q18. What fuel price forecasts were used in the IRP Process?

A18. The fuel price forecasts used in the IRP Process are described in Witness Manning's testimony. The fuel price forecasts for natural gas, coal, oil, and nuclear fuel are described below.

Natural Gas

Q19. How was the natural gas price forecast used in the IRP Process developed?

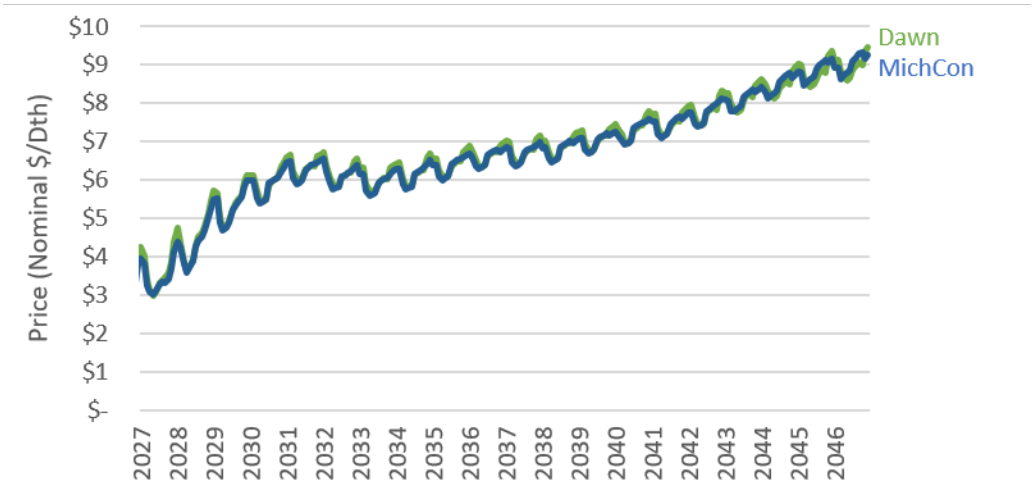
A19. Natural gas supply costs were added to transportation costs and other delivery costs to determine the delivered cost of natural gas to each generating facility.

Q20. How does the Company forecast gas supply costs?

A20. The methodology used for the forecast was based on the forecasted prices at the applicable natural gas hub locations in or around Michigan, including MichCon Citygate and Dawn. For 2026, these prices were determined using commodity and indices data for near-term futures prices. For 2027 through 2029, the forecast transitions from the near-term futures prices to the long-term gas price forecasts. The Company acquired the long-term gas price forecasts from Siemens Power Technologies International (Siemens), and Witness Manning describes the Siemens forecast in more detail in her testimony. The long-term Siemens forecast is used exclusively starting in 2030. The forecasts for MichCon Citygate and Dawn are shown in Figure 1 below. This forecast methodology is consistent with the process used by the Company in developing its forecasts for its PSCR Plan filings and the 2022 IRP.

Line No.

Figure 1: Natural Gas Long-Term Price Forecast



Q21. How has the accuracy of the Company's natural gas price forecasts compared to those of the U.S. Energy Information Administration (EIA) Annual Energy Outlook (AEO)?

A21. The EIA AEO forecasts have historically been higher than the actual price of natural gas over the last 15 years. Exhibit A-10 shows the EIA AEO nominal Henry Hub Natural Gas Spot Price projections published from 2009 – 2024 in lines 4-19. Line 1 shows the actual Henry Hub spot prices from 2010 – 2025. Lines 23-38 show the percent error of the forecasts compared to the actual prices.

This exhibit demonstrates that the EIA AEO forecast prices for individual years in 2010 – 2025 were higher than the actual price in 119 out of 135 predictions, with the predictions averaging 90% higher than actual.

Q22. How has the Company's gas price forecast methodology performed over the same period?

A22. Exhibit A-10.1 shows the historical accuracy of the market futures, which the Company used for the first year of the gas price forecast, before transitioning into the long-term Siemens forecast. The market futures have been more accurate than the EIA AEO projections. Exhibit A-10.1 shows the percent error of the market futures compared to the actual prices. The market futures averaged 55% higher than actuals while the EIA AEO was 90% higher. In addition, the market futures were a better predictor of actual spot prices than the EIA AEO in 84 of 125 instances.

The Company has used Siemens for the long-term natural gas price forecasts since 2014. Siemens' 2014 through 2024 forecast accuracy can be compared against the EIA AEO over the same time period. Exhibit A-10.2 shows this comparison. Like the market futures, Siemens' forecasts were also more accurate than the EIA AEO natural gas price forecasts. The Siemens forecasts averaged 32% higher than actuals while the EIA AEO has been 54% higher for the same period. The Siemens forecasts were a better predictor of actual spot prices than the EIA AEO in 44 of 63 instances. Because DTE Electric's natural gas price forecast methodology has historically been more accurate than the EIA AEO price forecasts, the Company continues to use this methodology for the natural gas price forecast in this IRP.

Q23. How were gas transportation and delivery costs determined?

A23. Transportation costs were added to the supply costs to represent the costs associated with transporting the gas from the relevant hub to the generating facility. Depending on the plant and location, transportation costs were based on existing agreements or LDC general service tariff rates.

Coal

Q24. How were the delivered coal price forecasts used in the IRP Process developed?

A24. Coal commodity costs were added to transportation rates, including railcar costs, to determine the delivered cost of coal by route to each generation facility.

Q25. How does the Company forecast coal commodity prices?

A25. For 2026 through 2028, the coal cost forecast was developed by utilizing existing contract prices and forward market prices. Forward market coal prices were based upon market information obtained from an over-the-counter coal broker. For 2029 and 2030, the forecasted coal cost was derived by applying an inflation index factor to the 2028 forward market coal prices. Beyond 2030, the Company utilizes the Siemens forecast escalation applied to the forward market coal prices. Witness Manning describes the Siemens forecast in more detail.

Q26. How does the Company forecast coal transportation rates for the remaining months of the current year and the subsequent five years?

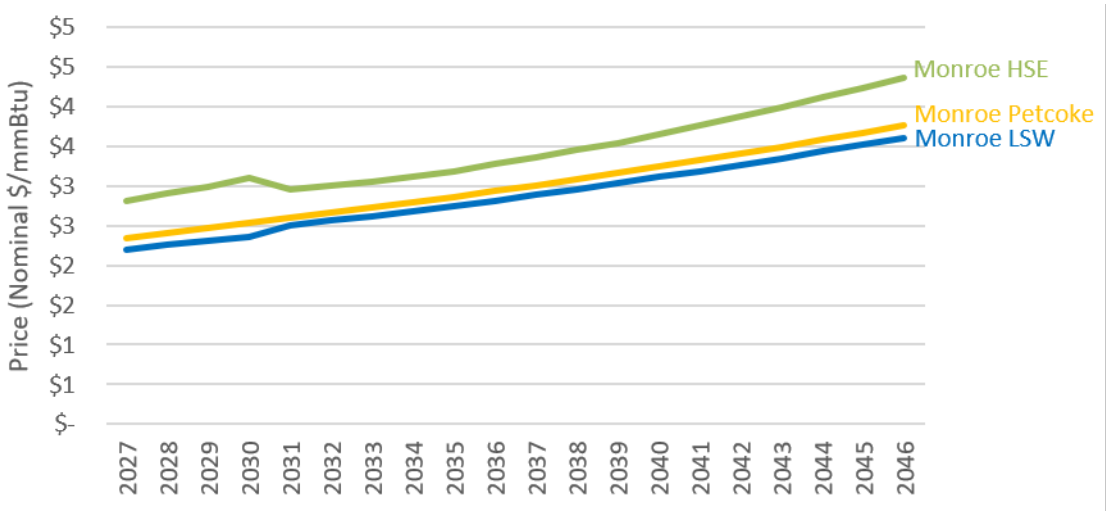
A26. The near-term transportation rates come from existing contract prices. After existing contract rates expire, the rates were computed by applying adjustments to existing contract rates using either contractually prescribed periodic rate increases, or rate increases based upon contractually defined cost indices. In the latter case, historical data was utilized to project future rate adjustments.

Q27. How was the petcoke price forecast developed?

Line No.

A27. Petcoke prices utilize existing contract prices, escalated through 2030. Then, the Siemens deflator series was applied each year on the forward price starting in 2031. The coal and petcoke price forecasts are shown in Figure 2 below.

Figure 2: Coal and Petcoke Long-Term Price Forecast



Fuel Oil

Q28. How are fuel oil price forecasts developed for existing generating plants?

A28. The forecasted delivered cost of fuel oil was determined by using the New York Mercantile Exchange (NYMEX) futures prices in addition to expected transportation costs. The fuel oil supply pricing was market index based with a constant markup applied by the supplier in accordance with existing contract terms.

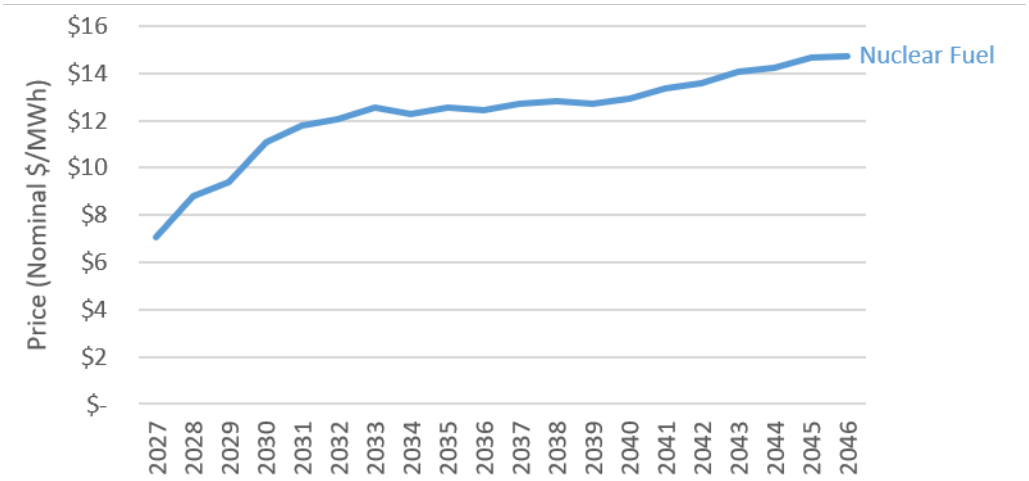
Nuclear Fuel

Q29. How are nuclear fuel price forecasts developed?

A29. The nuclear fuel cost forecast was developed utilizing current pricing and long-term market price forecasts. The long-term market price forecasts were based upon

information obtained from a nuclear industry market research and analysis company. The forecasted costs to purchase U3O8, conversion, UF6, enrichment services and/or fabrication for the fuel is then amortized over the period when heat is generated from the nuclear fuel during each reactor core operating cycle. The normal in-core life of a fuel bundle is less than 8 years, during which time the total front-end cost of the bundle is completely amortized on the basis of heat generated. The nuclear fuel cost forecast is shown in Figure 3 below.

Figure 3: Nuclear Fuel Long-Term Price Forecast



Q30. Are the sources and methodology to develop the fuel price forecasts used for this IRP filing consistent with the Company's annual PSCR filings?

A30. Yes. While the fuel forward prices may differ due to the timing of providing fuel price inputs, the methodology used in this IRP is consistent with the Company's annual PSCR filings. For the Reference scenario, the sources were the forwards and the Siemens fundamental forecast. Because the time period analyzed in this IRP filing is much longer than the time period analyzed for the Company's annual PSCR

filings, the long-term Siemens forecast was used beyond the initial years of the forecast.

Q31. How would you characterize the Company's fuel procurement strategy to supply its generating sites?

A31. As described in my testimony above, the Company has strategically contracted for firm gas transportation and storage for its BWEC site and many of its natural gas peaking sites to provide reliable and flexible supply while minimizing costs for its customers. For the Company's Monroe Power Plant coal-fired site, long-term coal and coal transportation agreements are structured to provide reliability of supply with sufficient flexibility to adapt to changing requirements to meet the needs of the site. The Company holds coal inventory on-site to mitigate potential coal supply disruptions and maintain reliability of supply for its customers. For Fermi 2, the Company has secured uranium and long-term arrangements for the services required to reliably fuel the plant. This approach results in reliable, flexible, and economic fuel supplies for these important sources of electric generation.

PART III: FUEL FORECASTS FOR POTENTIAL SUPPLY RESOURCES ANALYZED IN THE IRP MODELING PROCESS

Q32. How were the natural gas price forecasts developed for CCGT supply resources described in the IRP Process?

A32. In addition to other resource options, the IRP model included combined cycle gas turbines (CCGTs) as resources available for optimization. For a baseload generator such as a CCGT, the Company would expect to take an approach similar to BWEC and enter into firm transportation and storage agreements to provide supply

reliability. These firm agreements would have annual reservation charges to reserve capacity on the gas system. The reservation charges were estimated based on pipeline tariff rates and other sources of market intelligence. These costs were applied to the potential CCGT supply resources evaluated in the IRP Process by scaling the costs based on the plant's full load gas consumption. The firm services estimated provide for a high level of natural gas supply reliability to a power plant.

Q33. Did you develop natural gas price forecasts for any other gas-fired resource studies?

A33. Yes, I also developed natural gas price forecasts related to the natural gas conversion study for the Monroe Power Plant (Monroe Conversion Study). As described by Witness Pratt, the July 26, 2023 Order Approving Settlement Agreement in Case No. U-21193 required that DTE Electric perform this study. The Company commissioned a study from Burns & McDonnell to develop an overall project cost estimate for the Monroe natural gas conversion. To support the Monroe Conversion Study, I performed an assessment of the available gas supply and expected cost to deliver gas to the Monroe Power Plant site, and I relied on the Burns & McDonnell study, in part, to estimate the cost of new natural gas interconnection and pipeline facilities. Specifically, my assessment examined the case in which two Monroe units are converted from coal to natural gas, with a resulting natural gas requirement of 360,000 Dth/day.

Q34. Is there existing natural gas pipeline infrastructure at the Monroe Power Plant site?

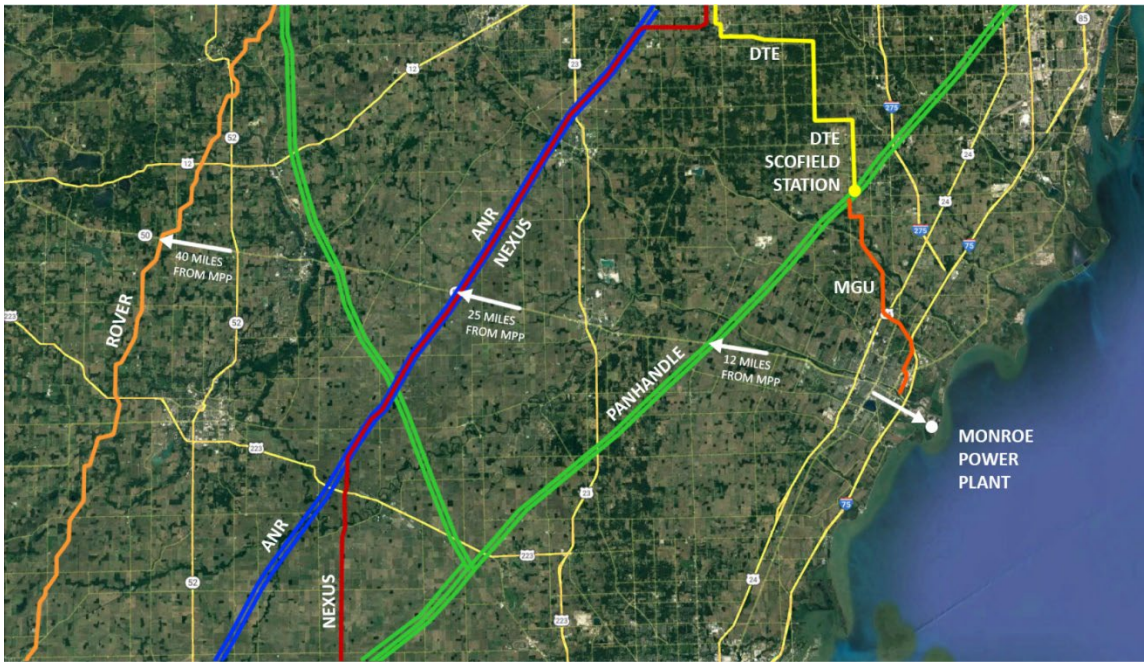
A34. No. There is no natural gas-fired generation capacity or pipeline infrastructure at the Monroe Power Plant site. The Monroe Power Plant is in the Michigan Gas Utilities (MGU) service territory; however, the MGU system does not have sufficient capacity to deliver the required quantities of gas. The Monroe Power Plant site is not optimal from a gas supply standpoint – the nearest major gas pipelines are at least twelve miles away.

Q35. What existing natural gas pipelines are located nearest to the site?

A35. There are several interstate and intrastate natural gas pipelines in the vicinity of Monroe Power Plant. Nearest to the site are the Panhandle Eastern Pipeline (PEPL) and the DTE Gas system at the Scofield station, approximately 12 miles from the Monroe Power Plant. The ANR Pipeline and the NEXUS Pipeline run parallel to each other approximately 25 miles away from the site. Lastly, the Rover pipeline is located approximately 40 miles away from the site. Figure 4 shows the approximate locations of pipelines in the area of the Monroe Power Plant site.

Line No.

Figure 4: Monroe Area Gas Pipelines



Q36. For the purposes of the Monroe Conversion Study, with which pipeline did DTE Electric assume it would interconnect?

A36. The natural gas conversion study focuses on Units 1 and 2 (Case 2). Therefore, DTE Electric assumed an interconnection with the DTE Gas system at Scofield. This location represents the nearest location with sufficient gas supply. Interconnecting at DTE Gas-Scofield provides access to a liquid gas supply hub and natural gas storage for balancing.

Q37. What are the estimated costs to construct an interconnection and lateral pipeline to the DTE Gas-Scofield location?

A37. The estimated cost to construct an interconnection and lateral pipeline to the DTE Gas-Scofield location is $135 million. The lateral pipeline is assumed to be 30” in diameter to deliver the required gas supply. The basis for the cost estimate is from

the gas pipeline construction cost study performed as part of the Burns & McDonnell study (NDA Exhibit A-4). The Burns & McDonnell study estimated the cost to construct a pipeline from the Monroe Power Plant site to NEXUS, and DTE Electric adjusted the cost to account for the shorter distance to DTE Gas-Scofield.

Q38. How would the Company contract for the construction of an interconnection and lateral pipeline?

A38. The Company typically solicits proposals and contracts with a gas pipeline company to construct, own, and operate a lateral pipeline and interconnection facilities. The pipeline company would typically undertake the costs and investments associated with constructing the pipeline, and DTE Electric and the pipeline company would enter into a long-term gas transportation agreement to effectuate service on the new lateral pipeline. DTE Electric would pay a fixed transportation charge, which would allow the pipeline company to recover the costs associated with constructing the pipeline over the term of the contract, which was assumed to be less than 10 years. The costs of the contract with the pipeline company are recovered via PSCR as gas transportation expense. Based on the estimated lateral pipeline cost, the annual gas transportation cost for the lateral is estimated at $30 million per year.

Q39. What is the estimated timeline associated with contracting for and constructing an interconnection and lateral pipeline?

A39. Given the diameter and length of the proposed lateral pipeline, the pipeline is expected to take several years to develop. Inclusive of the RFP process, pipeline

permitting, regulatory approvals, engineering, construction, and commissioning, the overall process is estimated to take between three and five years.

Q40. What gas transportation and storage services would be necessary for DTE Electric to deliver gas to the DTE Gas-Scofield location?

A40. To provide access to reliable and flexible gas supplies, DTE Electric assumes that it would contract for gas transportation and storage services on the DTE Gas system. The contracted gas transportation would provide DTE Electric reserved capacity on the DTE Gas system to supply Monroe Power Plant and provide access to the MichCon Citygate gas supply location. The contracted gas storage would allow DTE Electric to flexibly dispatch Monroe Power Plant in the energy market while managing the flow of gas supplies. The annual costs for gas transportation and storage services to supply Monroe Power Plant are estimated at $34 million and $26 million, respectively.

Q41. What are the total estimated annual costs to interconnect Monroe Power Plant to a natural gas pipeline and reliably deliver gas?

A41. Inclusive of the lateral, transportation, and storage costs, the total estimated annual costs to interconnect and deliver gas supply for the Case 2 scenario (i.e., conversion of Units 1 and 2 to natural gas) is approximately $90 million. Table 1 shows the components of the annual gas transportation and storage charges. These costs, in addition to the MichCon Citygate gas price forecast, were provided as inputs to the economic evaluation of the Monroe Power Plant gas conversion.

Table 1: Annual Gas Transportation & Storage Expense (Case 2)

Component	Annual Expense ($ millions)
Lateral/Interconnect	$30
DTE Gas Transportation	$34
DTE Gas Storage	$26
Total	**$90**

PART IV: FUEL SUPPLY PLAN AND FORECASTS FOR DTE ELECTRIC'S PROPOSED PROJECTS

Q42. Can you provide a brief description and location of the projects proposed in the Company's PCA?

A42. As described in Witness Pratt's testimony, the Company is seeking approval of three gas-fired generation resources in this application.

1) Michigan Power Cogeneration Project is an existing 138 MW natural gas fired combined cycle cogeneration facility, located in Ludington, Michigan.
2) The Livingston County Project is a nominal 1,400 MW combined cycle generating facility, located in Handy Township, Michigan.
3) The Monroe County Project is a nominal 700 MW combined cycle generating facility, located in Milan Township, Michigan.

From a natural gas supply perspective, these sites are well-positioned given their proximity to existing natural gas infrastructure and market hubs.

Michigan Power Cogeneration

Q43. Can you describe the existing natural gas infrastructure in close proximity to the Michigan Power Cogeneration facility?

A43. Michigan Power Cogeneration facility is an existing facility in DTE Gas's franchise service area, and DTE Gas owns and operates a system of natural gas transmission pipelines that serve the area. A DTE Gas transmission pipeline lateral directly serves the facility. The transmission pipeline terminates on the facility site at a DTE Gas owned meter station including metering, regulation, and fuel heating.

Q44. How much natural gas does the Michigan Power Cogeneration facility require?

A44. The facility can consume approximately 1,270 Dth/hour of natural gas at full load. At this consumption rate, the maximum daily quantity required by the plant is approximately 30,500 Dth/day.

Q45. How does the Company plan to provide reliable natural gas supply to the Michigan Power Cogeneration project?

A45. The Company plans to supply natural gas for the Michigan Power Cogeneration project in a similar method as it does for the Renaissance, Delray, and Dearborn CHP sites. DTE Electric intends to purchase natural gas at MichCon Citygate from a third-party gas marketer. The Company will deliver the gas to the plant under a firm end-use gas transportation agreement with DTE Gas. The transportation agreement with DTE Gas will include approximately 0.5 Bcf of gas storage capacity.

Q46. Will any new natural gas infrastructure be required to supply fuel to Michigan Power Cogeneration project?

A46. No. The Michigan Power Cogeneration Project is an existing facility that is currently served by DTE Gas. No additional infrastructure is required to continue the supply of fuel to the facility.

Q47. What is the expected annual delivered fuel cost for the Michigan Power Cogeneration Project?

A47. The annual delivered fuel cost for the Michigan Power Cogeneration Project is forecasted to range from $6.92 to $9.99 per MMBtu from 2030 – 2046. The fuel cost forecast for the Michigan Power Cogeneration project is shown in Figure 5 below. The fuel cost forecast uses forecasted MichCon Citygate prices for gas supply and adds the variable components of the DTE Gas transportation agreement to estimate the variable fuel costs. The Company also used the gas transportation agreement to forecast the annual fixed fuel costs of $3 million for gas transportation and storage.

Livingston County Project

Q48. Can you describe the existing natural gas infrastructure near the Livingston County Project?

A48. The Livingston County Project is in Consumers Energy's natural gas franchise service area, and while Consumers Energy has distribution pipelines serving customers in the area, these pipes are not sufficiently sized to serve the proposed facility. Consumers Energy's larger transmission pipelines are several miles away from the proposed site. Two large natural gas transmission pipelines – Vector Pipeline and Rover Pipeline – traverse the proposed Livingston County site. In aggregate, these pipelines have capacity to transport over 3 Bcf per day past the

site. The site is further advantaged by natural gas storage facilities in the area. DTE Gas Company and Washington 10 Storage Corporation are interconnected with Vector Pipeline, providing access to gas storage capacity to serve the site. Natural gas supply at the MichCon Citygate and Chicago hubs provide liquid markets to procure the required natural gas supplies, and Rover Pipeline provides access to Appalachian basin gas supply.

Q49. How much natural gas does the Livingston County Project require?

A49. As described by Witness Stansell, the Livingston County Project is designed as a two-unit configuration, consisting of two 1x1 single-shaft combined-cycle trains. Each of the trains can consume up to approximately 4,600 Dth/hour of natural gas at full load. At this consumption rate on both units, the maximum daily quantity required by the project is approximately 220,000 Dth/day. In addition, Witness Stansell explains that the Company has also evaluated future CCS implementation. When CCS is implemented at the Livingston County Project, the maximum daily natural gas consumption is estimated to increase to 285,000 Dth/day.

Q50. How does the Company plan to provide reliable natural gas supply to the Livingston County Project?

A50. The Company plans to solicit proposals from nearby service providers for firm gas transportation services covering the maximum consumption at the site, which may come from a combination of the providers described above. The Company also plans to solicit proposals for firm gas storage service. Storage services will provide the ability to balance supply purchases with the actual gas consumption at the

facility. In addition, storage provides a reliable source of supply that creates a buffer from market price volatility.

Q51. Will any new natural gas infrastructure be required to supply fuel to the Livingston County Project?

A51. Yes. While the Livingston County Project is close to existing gas transmission, interconnection facilities will need to be constructed to receive fuel from these pipelines. The Company expects to enter into agreements to connect the project to both the Vector and Rover pipelines. The scope of these agreements is expected to include construction of interconnection and metering facilities on the project site.

Q52. Will the cost of the new natural gas infrastructure be included in the Livingston County Project's capital cost?

A52. The Company expects that the new natural gas infrastructure will be owned and operated by the pipeline companies, and the costs will be passed to DTE Electric as a monthly reservation charge over the term of the firm service agreement. After the Livingston County Project achieves commercial operation, these fuel supply costs will be included in DTE Electric's Power Supply Cost Recovery (PSCR) factor.

Q53. What is the expected annual delivered fuel cost for the Livingston County Project?

A53. The annual delivered fuel cost for the Livingston County Project is forecasted to range from $7.46 to $10.20 per MMBtu from 2032 – 2046. The fuel forecast for the Livingston County project is shown in Figure 5 below. This fuel cost forecast

relies on the MichCon Citygate for the variable fuel costs and estimated annual fixed fuel costs of $58 million for transportation and interconnection facilities and $21.5 million for storage.

The Livingston County Project's access to multiple transmission pipelines and storage facilities, as well as access to a variety of supply basins and market hubs, should provide a competitive delivered cost of natural gas fuel to the project and the reliability and flexibility that best serves the needs of DTE Electric and its customers.

Monroe County Project

Q54. Can you describe the existing natural gas infrastructure near the Monroe County Project?

A54. The Monroe County Project is in DTE Gas's franchise service area, and DTE Gas has distribution pipelines serving customers in the area; however, these pipelines are not sufficiently sized to serve the facility, and DTE Gas's larger transmission pipelines are nearly twenty miles away from the proposed site. Two large natural gas transmission pipelines – NEXUS Pipeline and ANR Pipeline – are approximately five miles from the proposed site. In aggregate, these pipelines have capacity to transport nearly 3 Bcf per day past the site. The site is further advantaged by several nearby natural gas storage facilities. DTE Gas Company, Washington 10 Storage Corporation, and ANR Storage are accessible via NEXUS, ANR, and DTE Gas pipelines, providing adequate availability of gas storage capacity to serve the site. In addition, the natural gas hub at MichCon Citygate and points along ANR Pipeline provide liquid markets to procure a portion of the required natural gas

supplies, and the NEXUS Pipeline provides access to Appalachian basin gas supply.

Q55. How much natural gas does the Monroe County Project require?

A55. As described by Witness Stansell, the Monroe County Project is designed as a single-unit configuration, consisting of one 1x1 single-shaft combined-cycle train. This unit can consume up to approximately 4,600 Dth/hour of natural gas at full load. At this consumption rate, the maximum daily quantity required by the project is approximately 110,000 Dth/day. In addition, Witness Stansell explains that the Company has also evaluated future CCS implementation. When CCS is implemented at the Monroe County Project, the maximum daily natural gas consumption is estimated to increase to 142,500 Dth/day.

Q56. How does the Company plan to provide reliable natural gas supply to the Monroe County Project?

A56. The Company plans to procure firm gas transportation covering the maximum consumption at the site, which may come from a combination of the providers described above. These pipelines provide access to gas originating in the Appalachian, Gulf, Mid-Continent, and Canadian supply regions. DTE Electric expects that a portion of the gas required for the site will be procured at the MichCon Citygate, and DTE Gas transportation service will be required to deliver into either NEXUS or ANR Pipeline. NEXUS or ANR transportation service will be used for delivery to the site. The Company intends to procure storage services from either DTE Gas, Washington 10, or ANR Storage to cover the balancing requirements of the Monroe County Project.

Q57. Will any new natural gas infrastructure be required to supply fuel to the Monroe County Project?

A57. Yes. The Monroe County Project is approximately five miles from existing gas transmission, and interconnection facilities will need to be constructed to receive fuel from these pipelines. A pipeline lateral will be required to transport the gas from NEXUS and ANR to the project site. The Company intends to interconnect with both the NEXUS and ANR pipelines to provide reliability and flexibility in DTE Electric's procurement and delivery of natural gas for the site. The Company expects to enter into one or more agreements to connect the Monroe County Project to pipelines. The scope of such agreements may include construction of a new lateral pipeline, interconnection, and metering facilities. The basis for the cost estimate for these facilities is from the gas pipeline construction cost study performed as part of the Burns & McDonnell study mentioned previously, adjusted for the shorter lateral length.

Q58. Will the cost of the new natural gas infrastructure be included in the Monroe County Project's capital cost?

A58. No. As described above for the Livingston County Project, the Company expects that the new natural gas infrastructure for the Monroe County Project will be owned and operated by the pipeline companies, and the costs will be passed to DTE Electric as a monthly reservation charge over the term of the firm service agreement. The Company expects that these fuel supply costs for the Monroe County Project will be included in DTE Electric's PSCR factor after the project achieves commercial operation.

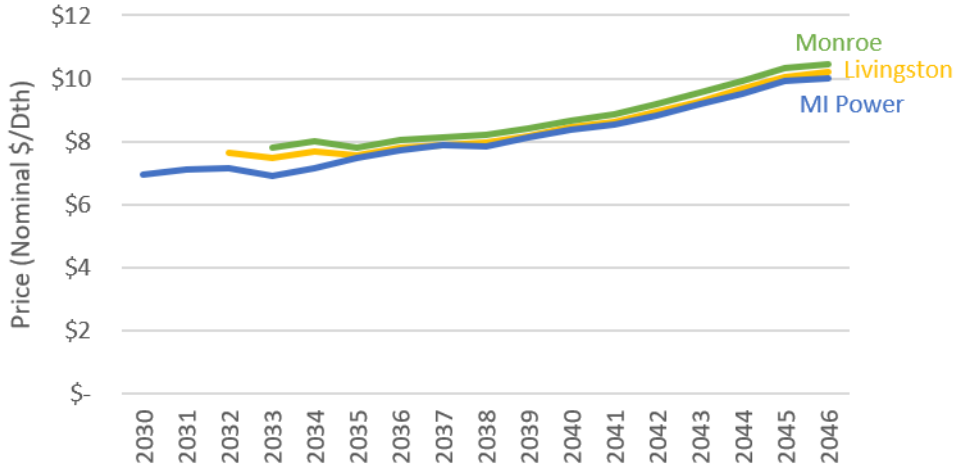
Line No.

Q59. What is the expected annual delivered fuel cost for the Monroe County Project?

A59. The annual delivered fuel cost for the Monroe County Project is forecasted to range from $7.79 to $10.47 per MMBtu from 2033 – 2046. The fuel forecast for the Monroe County Project is shown in Figure 5 below. This forecast relies on the MichCon Citygate for the variable fuel costs and estimated annual fixed fuel costs of $37.2 million for transportation and interconnection facilities and $10.7 million for storage.

The Monroe County Project's access to multiple transmission pipelines and storage facilities, as well as access to a variety of supply basins and market hubs, should provide a competitive delivered cost of natural gas fuel to the project and the reliability and flexibility that best serves the needs of DTE Electric and its customers.

Figure 5: Annual Average Delivered Gas Cost for the Proposed Projects



Q60. Does this complete your direct testimony?

A60. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEVIN L. BILYEU

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEVIN L. BILYEU

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Kevin L. Bilyeu (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company ("DTE Electric" or "Company").

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Walsh College in 2008 with a Bachelor of Business Administration. In 2012, I received a Master of Business Administration degree from the University of Michigan.

Q4. What is your work experience?

A4. Beginning in 2006, I launched my career at SEMCO Energy Gas Company, progressing through roles of increasing responsibility. I became a Billing Analyst in 2008, supporting stakeholders through reviews, project management, and process improvements. In 2011, I was promoted to Supervisor of Customer Accounting, overseeing billing, remittance processing, inactive collections, bad debt management, and financial reporting. In 2013, I advanced to Manager of Customer Energy Management, directing Energy Waste Reduction (EWR) program administration, supporting Michigan Public Service Commission ("MPSC" or "Commission") regulatory cases, and managing the home protection warranty program.

In 2015, I joined DTE Electric as Principal Marketing Analyst for EWR Pilot Programs, developing and managing new EWR initiatives. I became Principal Marketing Specialist of EWR Strategy in 2016, modeling energy efficiency for Integrated Resource Plans (IRPs) and supporting EWR regulatory filings. In 2018, I was promoted to Principal Supervisor of EWR Strategy, leading long-term strategic planning, IRPs, and regulatory filings.

In 2021, I became Manager of EWR Strategy and Evaluation, Measurement & Verification, responsible for EWR strategic planning, cost-effectiveness, program evaluation, and applying results to improve offerings for DTE Electric and DTE Gas. In 2023, I transitioned to Manager of Renewable Energy Strategy and Special Projects, supporting Renewable Portfolio Standard (RPS) compliance, renewable energy initiatives, and MPSC filings. I was promoted to my current role in 2025.

Q5. What is your current position with the Company?

A5. My title is Director, Renewable Energy Planning and Strategy.

Q6. What are your duties and responsibilities in your current position?

A6. I lead activities related to maintaining RPS compliance, planning and executing special projects for renewable energy, and filing applications with the MPSC, as I did in my previous role. In addition, I support activities related to land acquisition, capital planning, and financial modeling for DTE Electric's renewable energy portfolio.

Line No.

Q7. Have you previously sponsored testimony before the MPSC?

A7. Yes. I have sponsored testimony in the following cases:

U-17362	SEMCO Energy Gas Company Energy Optimization (EO) Plan Filing
U-18091	DTE Electric 2024 PURPA Filing
U-18419	DTE Electric Certificate of Necessity
U-20471	2019 DTE Electric Integrated Resource Plan
U-20876	2021-2022 DTE Electric EWR Plan
U-20881	2021-2022 DTE Gas EWR Plan
U-21193	2022 DTE Electric Integrated Resource Plan
U-21313	2022 DTE Electric and DTE Gas EWR Reconciliation
U-21353	2022 DTE Electric Renewable Energy Cost Reconciliation
U-21496	2023 DTE Electric Renewable Energy Plan Accounting Application
U-21550	2023 DTE Electric Renewable Energy Cost Reconciliation
U-21662	2024 DTE Electric Amended Renewable Energy Plan
U-21772	2025 DTE Electric Depreciation Accrual Rates
U-21990	2025 DTE Electric Special Contract for Electric Service
U-22058	2026 DTE Electric Special Contract for Electric Service

Line No.

Purpose of Testimony

Q8. What is the purpose of your direct testimony?

A8. The purpose of my direct testimony is to:

- Discuss the Renewable Portfolio Standard (RPS) requirements related to 2008 Public Act 295, as amended by 2016 Public Act 342 (PA 342) and 2023 Public Act 235 (PA 235);
- Discuss the renewable energy resources included in the Integrated Resource Plan (IRP) starting point, including resources serving the Company's Voluntary Green Pricing (VGP) program;
- Describe the assumptions used for developing forecasts for utility-scale renewable energy resources in the IRP process;
- Describe the utility-scale wind and solar energy resources included in DTE Electric's proposed course of action (PCA); and
- Describe any additional assumptions and considerations pertaining to renewable energy resources.

Q9. Are you sponsoring any exhibits in the proceeding?

A9. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-11	Summary of Renewable Resources

Q10. Was this exhibit prepared by you or under your direction?

A10. Yes, it was.

Q11. Did you provide inputs to the group responsible for conducting the IRP modeling process?

A11. Yes. As further described by Witness Manning and discussed later in my testimony, I provided the renewable resource information used to develop the IRP starting point, including DTE Electric's Commission-approved RPS and VGP renewable resources through 2030, along with the assumptions used to forecast installed costs and capacity factors for potential new renewable resources. These assumptions were used to determine the IRP's PCA which involved modeling potential renewable resource additions beyond those included in the starting point during the 2027 through 2046 IRP planning period. The starting point also includes renewable resource planning assumptions associated with the contracted Oracle America Cloud Services LLC (OACS) load and pending Google LLC (Google) load.

Q12. How does the resource plan reflected in the IRP's PCA relate to the concurrently filed Amended REP in Case No. U-22057?

A12. The IRP evaluates renewable resources alongside other resource options as part of the Company's PCA for meeting forecasted energy and capacity needs and applicable statutory requirements. The resource plan in the PCA provides the planning basis for the Amended REP. The Amended REP reflects the renewable resource plan included in the PCA and presents the Company's plan for forecasted compliance with the RPS requirements established by PA 235.

Q13. How is your testimony organized?

A13. My testimony consists of the following five parts:

- Part I: Statutory Renewable Portfolio Standard

- Part II: Renewable Energy Resources Included in the IRP Starting Point
- Part III: Renewable Energy Assumptions
- Part IV: Renewable Energy Resources Included in the PCA
- Part V: Other Renewable Energy Considerations

PART I: STATUTORY RENEWABLE PORTFOLIO STANDARD

Q14. What are the RPS targets established by the Michigan Legislature in PA 235?

A14. Michigan's RPS requirements are established in PA 235, which was signed into law on November 28, 2023, and among other things, amended Sections 22 through 49 of PA 342. The law increased the statutory RPS requirement for electric providers to 50% in years 2030 through 2034, and 60% in 2035 and thereafter. Compliance with the RPS is addressed through the Company's renewable energy plans (REPs) filed with and approved by the Commission.

Q15. What total retail sales figure does the Company use to determine its RPS target?

A15. Consistent with Section 28(2)(b) of PA 235, the Company uses weather-normalized megawatt-hours of bundled load sold during the previous year, less the amount of sales attributable to customers participating in a VGP program and the outflow from customers participating in the distributed generation (DG) program.

Q16. How are Renewable Energy Credits (RECs) generated to meet the RPS targets?

A16. In general, one REC is granted for each megawatt-hour of electricity generated from the renewable energy system. RECs can be generated through several methods

defined in Section 28(5) of PA 235. This includes "(a) Generating electricity from renewable energy systems for sale to retail customers. (b) Purchasing or otherwise acquiring renewable energy and capacity. (c) Purchasing or otherwise acquiring renewable energy credits without the associated renewable energy or capacity…" REC-only purchases made under Section 28(5)(c) shall not exceed 5% of the Company's compliance amount.

Q17. Can RECs be banked if not used towards RPS compliance in the year in which they are generated?

A17. Yes. Under Section 39(3) of PA 235, "A renewable energy credit expires at the earliest of the following times: (a) When used by an electric provider to comply with its renewable energy standard. (b) When substituted for an energy waste reduction credit under section 77. (c) Five years after the end of the month in which the renewable energy credit was generated." Based on this provision, DTE Electric may bank RECs for up to five years from their creation date.

Q18. Do renewable energy generation and RECs count toward Clean Energy Standard (CES) compliance?

A18. Yes. The Commission-approved Clean Energy Plan (CEP) template[1] identifies Company-Owned Renewable Energy (MWh) net of VGP, Renewable Energy PPAs (MWh) net of VGP, purchased RECs, and RECs reported and retired pursuant to MCL 460.1029(4) as resources that contribute toward CES compliance.

Q19. What is the purpose of the Company's VGP programs?

[1] Case No. U-21867 Order, dated December 18, 2025 (pp. 48-50 and Appendix A)

A19. Section 61 of 2016 PA 342 mandates that all utilities offer voluntary renewable energy programs to their customers. Voluntary green pricing programs allow customers to choose how much of their electricity usage will be supported by renewable energy. Under this program, the electric provider offers a set of renewable energy options, and customers may elect the portion of their electricity that they want to be sourced from renewable generation. Participation is optional, and the program is designed to give customers a direct, flexible way to increase their use of renewable energy beyond renewable portfolio standards.

Q20. How do sales associated with VGP programs impact RPS requirements?

A20. As noted above, load participating in the Company's VGP program is removed from the bundled retail load count, thereby lowering the Company's overall RPS obligation. When a customer enrolls, whether through the standard offering or a special contract, the enrolled portion of their load does not contribute to increases in RPS targets.

Q21. Does the Company offer VGP special contracts to accommodate unique customer situations?

A21. Yes. In the June 9, 2021 Order in Case No. U-20713, the Commission approved a settlement agreement that established a customer-requested offering within the Company's VGP program. This offering supports unique, customer driven renewable energy projects that fall outside the standard Rider 17 options. Under this structure, the Company designs and constructs dedicated renewable energy projects that support each participating customer's specific sustainability goals. As

with the other VGP offerings, load served by these customer-specific offerings reduces the Company's RPS targets.

Q22. How is VGP accounted for in CES compliance?

A22. The Commission-approved CEP template separately reports VGP generation as an energy resource measured in megawatt-hours. As discussed in the Commission's Order in Case No. U-21867, dated December 18, 2025 (pp. 48-50 and Appendix A), the approved template distinguishes VGP energy from the separate accounting and reporting of RECs for CES compliance purposes.

Q23. What is the relationship between this IRP filing and the Amended REP filed in Case No. U-22057?

A23. At a high level, the IRP evaluates the renewable resources reflected in the Company's PCA as part of an IRP designed to meet customers' forecasted energy and capacity needs and applicable statutory requirements, including the RPS established under Act 295, as amended. In its April 25, 2024 Order in Case No. U-21568, the Commission stated that "IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning" because IRPs allow renewable resources to be evaluated alongside other resource options. The Commission further stated that future amended REPs should reflect the assumptions included in the utility's most recently approved IRP. Consistent with that guidance, this IRP serves as the foundation for the Amended REP.

Q24. How does the Amended REP differ from the IRP?

A24. While the IRP evaluates renewable resources as part of the Company's broader plan for meeting forecasted energy and capacity needs, the Amended REP is the specific statutory filing through which the Company demonstrates forecasted RPS compliance and seeks approval of its REP. The Amended REP includes the Company's forecasts of renewable energy generation, REC requirements, REC acquisitions and retirements, and the costs associated with implementing the Amended REP through 2045[2]. Consistent with the Commission's direction in Case No. U-21990, the Company is filing the Amended REP concurrently with this IRP in a separate docket.

Q25. Will the Company submit projects to the Commission for review and approval prior to construction?

A25. Specific renewable projects selected to implement the IRP and satisfy the REP will be submitted for Commission approval through the separate ex parte approval process as discussed in Part IV.

PART II: RENEWABLE ENERGY RESOURCES INCLUDED IN THE IRP

STARTING POINT

Q26. How are renewable energy resources and related planning assumptions reflected in the IRP model starting point?

[2] The IRP planning period extends through 2046, while the Company's Amended REP is through 2045.

A26. The renewable resources and related planning assumptions included in the IRP modeling starting point are categorized based on their regulatory status and the planning purpose for which they were included:

- Existing and Commission-approved renewable resources used or planned to support compliance with the RPS requirements established by PA 235
- Existing and Commission-approved VGP resources
- Additional renewable resource amounts included as planning assumptions to support forecasted RPS compliance
- Renewable resources associated with contracted and forecasted VGP demand, including the pending Google VGP Special Contract

Exhibit A-11 identifies the renewable resources and planning assumptions included in each category and how they are classified for purposes of the IRP modeling starting point. Details on the IRP modeling starting point are addressed by Witness Manning in her testimony.

Q27. What renewable resources that are currently in service or Commission-approved for future service are included in the IRP starting point to support compliance with PA 235's RPS requirements?

A27. DTE Electric included approximately 2,517 megawatts (MW) of renewable resources that are either in service or Commission-approved for future service in the IRP starting point for purposes of RPS compliance. Of that amount, approximately 1,749 MW consists of Company-owned or contracted qualifying renewable energy resources that are currently in service, including wind, solar, biomass, and landfill gas resources. These in service projects are detailed on lines

1-11, 18-28, and 35-60 of Exhibit A-11. The resources are comprised of approximately 1,006 MW of Company-owned wind, 458 MW of contracted wind, 63 MW of Company-owned solar, 199 MW of contracted solar, 17 MW of contracted biomass, and 6 MW of contracted landfill gas.

In addition, the starting point includes approximately 186 MW of contracted solar and 582 MW of Company-owned solar that have received Commission approval and are planned for future service to support RPS compliance, as shown in lines 12-13 and 61-65 of Exhibit A-11. Collectively, these Commission-approved resources planned for future service total approximately 768 MW.

Q28. What renewable resources that are currently in service or Commission-approved for future service are included in the IRP starting point to support the Company's VGP program?

A28. DTE Electric included approximately 2,291 MW of renewable resources that are either in service or Commission-approved for future service in the IRP starting point to support the Company's VGP program. Of that amount, approximately 1,234 MW consists of renewable resources currently in service, as shown on line 85 and lines 90-99 of Exhibit A-11. The remaining approximately 1,057 MW consists of Commission-approved renewable resources planned for future service, as shown on lines 86-87 and 100-112 of Exhibit A-11. Any unsubscribed portions of these assets can count toward RPS compliance.

Q29. What are the Company's forecasted RPS requirements for the years 2027 through 2045?

Line No.

A29. Based on RPS targets of 15% of total retail sales[3] through 2029, 50% from 2030 through 2034, and 60% beginning in 2035, the Company's forecasted RPS requirements for 2027 through 2045 are equivalent to the MWh volumes[4] shown in Table 1.[5]

Table 1 Forecasted RPS Requirements

Year	REC Requirement
2027	5,612,520
2028	6,096,292
2029	7,226,626
2030	25,453,062
2031	24,658,152
2032	23,855,218
2033	23,475,960
2034	23,495,997
2035	28,311,804
2036	28,434,286
2037	28,643,047
2038	28,741,105
2039	29,026,816
2040	29,316,643

[3] Less the amount of sales attributable to customers participating in a VGP program and the outflow from customers participating in the distributed generation program
[4] One MWh of renewable energy is equal to 1 REC and the Company retires RECs for RPS compliance
[5] Although the IRP planning period extends through 2046, Table 1 presents the RPS forecast through 2045 from the Company's concurrently filed Amended REP.

Year	REC Requirement
2041	29,672,264
2042	29,873,868
2043	30,151,852
2044	30,412,170
2045	30,732,790

Q30. What renewable resources and related planning assumptions, aside from the resources that are currently in service or Commission-approved for future service discussed above, are incorporated into the IRP starting point?

A30. In addition to the renewable resources that are currently in service or Commission-approved for future service discussed above, the IRP starting point includes 4,863 MW of additional renewable resource amounts included as planning assumptions to support forecasted RPS compliance. These amounts are identified on lines 14-17, 29, and 66-78 in Exhibit A-11 and reflect the renewable resources assumed for planning purposes based on forecasted retail sales and the resulting RPS requirements, including the renewable resource planning assumptions associated with the OACS load. As Witness Manning explains, inclusion of these renewable resource amounts in the IRP starting point does not alter the regulatory or contractual status of any particular resource or planning assumption, constitute Commission approval of a specific renewable project or its costs, or establish that a particular project is directly or exclusively assigned to OACS.

The IRP starting point also includes 2,270 MW of additional renewable resource amounts as planning assumptions associated with forecasted VGP demand. These

resources are shown in lines 88-89 and 113-123 in Exhibit A-11 and include renewable resource planning assumptions associated with the Google load.

Q31. What is the Company's current five-year subscription forecast for its VGP program?

A31. The Company's forecasted VGP subscriptions for 2027 through 2031 are shown in Table 2.

Table 2 VGP Forecast

Year	Cumulative MWh
2027	3,211,264
2028	4,544,709
2029	6,067,686
2030	7,237,633
2031	8,874,771

Q32. Is the Company seeking any Commission action regarding the VGP program in this IRP proceeding?

A32. No, the VGP forecast and product offerings are currently pending before the Commission in Case No. U-21375. Further, as discussed above, the Company filed an Amended REP concurrently with this IRP to incorporate builds for customer-requested contracts, in accordance with the Settlement Agreement in Case Nos. U-20713 and U-20851.

PART III: RENEWABLE ENERGY ASSUMPTIONS

Q33. What renewable energy technologies are considered in the IRP?

A33. The IRP modeling includes utility-scale solar, residential solar, solar-storage hybrid, onshore and offshore wind, geothermal, biomass, and residential, commercial, and other DG resources.

Q34. How were the installed cost assumptions developed for solar and wind resources in the IRP?

A34. For solar projects, DTE Electric used its most recently approved solar investments in Case No. U-21193, which were filed on July 31, 2025, as the baseline in 2028. These include four self-developed solar projects with a 2028 commercial operation date. To forecast future costs, the Company applied a cost curve based on an installed cost forecast from the 2024 National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB), along with an inflation factor.

For wind projects, DTE Electric used cost assumptions from a project that the Company is in the early stages of developing in Michigan as a baseline in 2029. The Company would typically use an approved project, but the last approved project achieved commercial operation in 2023 and does not reflect the current market. To forecast future costs, the Company applied a cost curve based on an installed cost forecast from the 2024 NLR ATB, along with an inflation factor.

Q35. How were the net capacity factors developed for wind and solar resources in the IRP?

A35. For Company-owned and power purchase agreement (PPA) projects that are operational or approved at the time of this filing, the forward-looking capacity factor projections are consistent with the approved plan from the Company's prior amended REP Case No. U-21662.

Consistent with the resource assumptions discussed above, DTE Electric used its most recently approved solar investments in Case No. U-21193, which were filed on July 31, 2025, as the baseline in 2028. These include four self-developed solar projects with a 2028 commercial operation date. The Company applied a production curve based on a net capacity factor forecast from the 2024 NLR ATB. For solar projects, the Company uses Class 9 moderate assumptions. NLR provides solar assumptions for 10 resource classes in the United States, binned by mean global horizontal irradiance (GHI). Most of Michigan is in the <4 GHI Bin.

For wind projects, DTE Electric used net capacity factor assumptions from a project that the Company is in the early stages of developing in Michigan as a baseline in 2029. The Company would typically use an approved project, but the last approved project achieved commercial operation in 2023 and does not reflect the latest technology assumptions. The Company applied a production curve based on a net capacity factor forecast from the 2024 NLR ATB. For wind projects, the Company used NLR Class 8 moderate assumptions. NLR provides wind assumptions for 10 wind speed classes, based on annual mean wind speed (m/s). The average speed for our current wind fleet is 6-7 m/s and for wind speed in the range of 6.53-7.1 m/s the corresponding resource class is Class 8.

Q36. What assumptions were used regarding the location of renewable energy projects?

A36. The Company's PCA assumes that new renewable energy resources are located within Midcontinent Independent System Operator (MISO) Zone 7.

To evaluate the impact of potential limitations on renewable development in Michigan, the Company also developed assumptions for renewable resources located in other MISO states. These assumptions were used to support the renewable reduction sensitivity described by Witness Manning. That sensitivity limited, for six years, the Company's ability to procure or construct 20% of the renewable resources otherwise assumed to be developed in Michigan. For modeling purposes, the renewable resource amounts affected were assumed to be available from locations outside Michigan.

Q37. What assumptions were used for renewable resources assumed to be located outside Michigan in the renewable reduction sensitivity?

A37. The Company used net capacity factor assumptions in the 2024 NLR ATB for solar resources in Arkansas and wind resources in Wisconsin. Arkansas and Wisconsin were chosen as modeling proxies based on expected renewable-resource performance and the Company's assessment of potential development feasibility. The assumptions were used to test the modeling effects of obtaining a portion of the assumed renewable resources from outside Michigan. They do not identify preferred procurement locations or limit the states or projects the Company could consider in actual procurement.

Q38. What are the Company's assumptions regarding operations and maintenance (O&M) expenses and ongoing capital expenditures for renewable resources in the IRP?

A38. The Company used forecasts of O&M expenses and ongoing capital expenditures for renewable resources that are primarily informed by DTE Electric's experience with contractor pricing and operating renewable energy facilities. The ongoing capital forecasts reflect anticipated expenditures during the operating life of the renewable resources, including the potential replacement of equipment such as solar inverters and wind-turbine gearboxes. These O&M and ongoing capital assumptions were included in the IRP modeling inputs and are also described in the Company's concurrently filed Amended REP in Case No. U-22057.

Q39. How did the Company account for tax credits in the IRP?

A39. The Production Tax Credit (PTC) and the Investment Tax Credit (ITC) are federal income tax credits enacted to incentivize the production of energy from and investment in renewable energy resources, respectively, but are currently undergoing a major phase-out. For the IRP modeling, wind and solar resources first selectable in 2028 were not assumed to qualify for a PTC or ITC because the Company determined that those modeled resources would not satisfy the applicable begin-construction and safe-harbor assumptions. Witness Busse describes the resource-specific tax-credit assumptions used in the IRP model, and Witness Hajj discusses the related federal policy changes. The concurrently filed Amended REP separately reflects tax-credit assumptions for identified renewable projects, including projects expected to generate credits after being placed in service.

Q40. Does the Company's ability to achieve the RPS targets rely on assumptions outlined in the Amended REP?

A40. The Amended REP, which has been concurrently filed under Case No. U-22057, runs through 2045 and is based on the Company's best estimates and forecasts on a wide range of factors. The Company's REC portfolio could vary from what is depicted in the Amended REP, affecting the Company's ability to comply with the RPS, if any of the following critical assumptions prove to be materially different:

- Annual retail sales volume
- PSCR Transfer Prices
- Capacity factors
- Installed costs
- O&M costs
- Applicable property taxes
- Commercial operating dates
- Tax Credits
- Allowance for Funds Used During Construction (AFUDC)

Q41. What risks could affect the development of renewable energy systems required to meet the higher RPS targets?

A41. Several risks may impact the Company's and developers' ability to build the necessary renewable energy systems needed to achieve higher RPS targets, including:

- **Special Use Permits:** Local opposition, community approval delays, and strict community requirements have delayed construction and increased pricing for

renewable energy projects. RPS requirements and state siting[6] discussions have increased local awareness for the demand for renewables, which has driven increased opposition.

- **Siting/Land Acquisition:** With the increased demand for renewable energy and the possibility of state siting, many developers are competing to acquire land to develop projects. In the past, projects have encountered environmental and infrastructure constraints late in the process, requiring changes to project layouts, and requiring more land, which can cause significant delays.
- **Transmission Upgrades / Backfeed Delays:** Interconnection upgrades are significantly delayed due to the increase in renewable generation in Michigan and throughout MISO. Projects continue to be impacted due to the delays in electrical backfeed.
- **MISO Definitive Planning Phase Process:** The MISO generation interconnection (GI) process has experienced material delays, particularly in legacy queue cycles, and MISO continues to implement reforms intended to shorten study timelines and reduce cascading restudies. The Company therefore treats interconnection timing and potential delay as a material renewable development risk.
- **Trade Tariffs:** A series of recently implemented trade tariffs and ongoing trade actions, including elevated duties on solar components, FEOC (Foreign Entity of Concern)-related requirements, and broader import tariffs, are influencing developer build strategies and increasing project costs.
- **Regulatory Uncertainty:** Potential changes in elected office at the state and federal level could result in market uncertainty that would impact both the ability

[6] Public Act 233 of 2023 established a siting process at the Commission for utility scale wind, solar, and energy storage facilities

to raise capital and to timely advance projects through the development and regulatory process.

PART IV: RENEWABLE ENERGY RESOURCES INCLUDED IN THE PCA

Q42. Did the Company include a cumulative MW limit in its IRP modeling for the amount of new wind and solar capacity that the IRP model could select above the starting point?

A42. Yes. The Company applied maximum cumulative limits on renewable resource additions that the IRP model could select above the starting point during the 2027 through 2046 planning period. Based on the assumptions below, the model was permitted to select up to approximately 59,400 MW of solar capacity and 6,300 MW of wind capacity above the starting point. These were cumulative limits over the planning period, not annual limits on the amount the model could select in any particular year. Witness Manning further explains how these limits were implemented in the IRP modeling.

Q43. How did the Company develop the cumulative wind and solar limits used in the IRP modeling?

A43. To develop the limits, the Company retained Atwell, a land development consultant, to evaluate the amount and distribution of land in Michigan potentially suitable for renewable development after applying identified environmental, infrastructure, and viable land constraints. The resulting potentially suitable acreage was converted to indicative nameplate capacity using the acres-per-MW values required for applicable MISO submissions and then adjusted based on DTE Electric's Zone 7 load ratio share and a 25% factor reflecting the Company's

Line No.

historical land acquisition experience. The results, as shown in Table 3, support the maximum cumulative renewable resource additions for wind and solar available in the IRP model during the planning period:

Table 3 Land Constraints

	Total Acres	Acres/ MW[7]	Total MWs	DTE Zone 7 Load Ratio	Success Factor[8]	MWs for DTE[9]
Solar	2,379,236[10]	5	475,847	50%	25%	59,481
Wind	2,523,900	50	50,478	50%	25%	6,310

Q44. Did the renewable resource additions reflected in the PCA exceed either cumulative modeling limits?

A44. No. The cumulative solar and wind additions reflected in the PCA remained below the respective modeling limits described above. Witness Manning provides additional details on the renewable resources selected above the IRP starting point.

Q45. What incremental wind and solar resource additions are reflected in the PCA above the IRP starting point?

A45. The PCA reflects the following incremental renewable-resource additions above the IRP starting point:

- 2027 through 2031: 1,050 MW of solar and 150 MW of wind
- 2032 through 2036: 4,550 MW of solar and 600 MW of wind
- 2037 through 2046: 0 MW of solar and 0 MW of wind

[7] Based on MISO requirements
[8] Based on DTE Electric's historical success on acquiring land
[9] The resulting values are modeling limits and are not forecasts that the Company will develop those quantities or determinations that all identified acreage is available or suitable for a particular project
[10] Subtracts 197,620 acres of overlap with wind developable land

Witness Manning explains how these incremental additions were incorporated into the final PCA, and Witness Hajj provides an overview of the PCA.

Q46. Could the costs of implementing the renewable resource additions reflected in the PCA vary from the amounts currently forecasted?

A46. Yes. The costs associated with implementing the renewable resource additions reflected in the PCA may vary based on factors such as tax credits, tariffs, MISO interconnection delays, and inflation, among other variables, that could either raise or lower the Company's implementation costs. The build plan and its related costs will be updated in future amended REP filings, in accordance with PA 235.

Based on the analyses presented in this proceeding, the Company concluded that the renewable resources reflected in the PCA form part of the most reasonable and prudent resource plan for meeting customers' forecasted energy and capacity needs and applicable RPS and CES requirements. Additionally, DTE Electric remains committed to procuring renewable resources through the request for proposals ("RFP") process, as further detailed in the next section of my testimony.

Q47. Does the Company propose to submit renewable projects selected to implement the approved IRP through subsequent ex parte applications?

A47. Yes. The Company requests authorization to submit subsequent ex parte applications seeking approval of eligible renewable projects, associated contracts, and project costs, as applicable, after the projects have been selected through an RFP process consistent with the Commission's Competitive Procurement Guidelines. Each application will demonstrate that the proposed project is

consistent with the renewable resource additions approved in this IRP and satisfies the applicable statutory and Commission-approved requirements for project-specific approvals.

Q48. Why is the Company requesting authorization to use a subsequent ex parte approval process?

A48. The requested process is consistent with the implementation framework contemplated by MCL 460.6t. The Commission has concluded that the plain language of MCL 460.6t(11) through (13) demonstrates that the Legislature intended costs and specific projects to be refined through subsequent applications and proceedings after approval of an IRP.[11] The Commission has also recognized that approved IRP settlements may contemplate subsequent ex parte applications for resources consistent with the approved IRP.[12]

Under the framework requested here, the Commission would first approve the renewable resource additions reflected in the PCA, including their targeted timing and forecasted costs. The Company would then competitively procure specific projects to implement that approved resource plan and submit the selected projects, associated contracts, and project costs for Commission review and approval. This approach avoids duplicating the resource need and portfolio determinations made in the IRP while preserving Commission review of whether each specific project is

[11] Commission Order in Case No. U-21189 dated August 30, 2023, pages 50-52; see also Commission Order in Case No. U-21193 dated April 11, 2024, pages 4-5.
[12] *Id*.

consistent with the approved IRP, resulted from the required competitive procurement process, and satisfies the applicable cost approval standards.

A subsequent ex parte process also supports timely procurement. Renewable development and acquisition opportunities may be subject to commercial deadlines and changing market conditions. A defined implementation process allows the Company to seek streamlined approval of competitively selected projects while providing the Commission with the project-specific information.

Q49. Would approval of the requested ex parte process mean that a specific project is automatically approved because it is consistent with the renewable resource additions reflected in the PCA?

A49. No. Approval of the IRP will establish the resource planning basis for subsequent project procurement, but it will not itself approve unidentified projects or their costs. In each subsequent application, the Company would provide the information necessary for the Commission to determine that the specific project is consistent with the approved IRP and satisfies the applicable requirements. If the Commission determines that a filing cannot appropriately be resolved ex parte, the requested framework does not limit the Commission's authority to require additional procedures.

Q50. Would use of the requested ex parte process change the standards governing Commission review of a project or its costs?

A50. No. The requested process would not change the Competitive Procurement Guidelines, the information submitted for Commission review, or the applicable

standards governing approval of a project and its costs. It would establish a more efficient procedural mechanism for reviewing specific projects selected to implement the renewable resource additions approved in this IRP. The Company would remain responsible for demonstrating in each application that the project satisfies the applicable requirements for Commission approval.

Q51. Does the renewable energy build plan reflected in the PCA support the Company's forecasted compliance with the RPS?

A51. Yes. The renewable energy build plan reflected in the PCA is forecasted to provide sufficient RECs to satisfy the Company's forecasted REC requirements provided above in Table 1. The Company's concurrently filed Amended REP in Case No. U-22057 presents the supporting forecast of REC requirements, generation, acquisitions, retirements, and balances through 2045. That analysis is presented in Exhibit A-2 to my testimony in the Amended REP proceeding (Case No. U-22057).

PART V: OTHER RENEWABLE ENERGY CONSIDERATIONS

Q52. What assumptions has the Company made regarding the ownership of future renewable energy resources?

A52. Through 2030, the Company applied the ownership allocation requirements established in the 2022 IRP Settlement Agreement in Case No. U-21193. After 2030, the Company remains agnostic to the ownership allocation between Company-owned and third-party owned resources. DTE Electric remains committed to procuring renewable assets cost-effectively through the RFP process.

Q53. How do the Company's competitive bidding processes ensure that each bidder is treated in a fair and nondiscriminatory manner?

A53. The Company has implemented a number of competitive RFP processes associated with implementation of the Company's IRP, consistent with the competitive bidding procedures described in Case No. U-15806 and approved by the August 25, 2009 Commission Order; the September 9, 2021 Competitive Procurement Guidelines in Case No. U-20852; and the Company's IRP Settlement Agreement approved in the Commission's July 26, 2023 Order in Case No. U-21193. MPSC Staff has audited the Company's RFP processes conducted to date. For the 2025 All-Source RFP, Staff completed its audit without identifying deficiencies, concerns, or recommended corrective actions, as described by Witness Pratt. The Company will continue to use and abide by the competitive procurement guidelines as defined by the Commission in all future generation competitive procurement processes related to this IRP. The Company intends to continue following its established and audited processes in any future RFPs that may be needed, with appropriate improvements, which generally includes the following steps:

- Maintain a list of potential qualified suppliers. DTE Electric maintains a list of companies who have contacted the Company regarding interest in future Requests for Information or RFPs.
- Meet with the MPSC Staff to review the goals of each RFP and bid evaluation methodologies consistent with Section 5 of Attachment D to the December 4, 2008 Temporary Order in MPSC Case No. U-15800, the Competitive Procurement Guidelines, and the 2022 IRP Settlement Agreement.

Line No.

- Utilize an independent monitor (IM) to provide support and oversight of the Company's RFP development, administration of the bidding, and proposal evaluation processes.
- Develop timelines for individual RFPs, which may vary depending on the complexity of the product(s) being sought and other potential factors.
- Include the following information for each RFP:
    - Description of the key attributes that will be considered when evaluating proposals;
    - Detailed instructions on how to organize proposals and what specific information is required in each section of a bidder's response, how to submit proposals, and how to navigate through the bidding platform or bidding process;
    - A confidentiality agreement between the Company and potential supplier to be executed and included with the proposal submission; and
    - Pro forma contracts for the product(s) described in the RFP.
- Receive all RFP responses via a secure, web-based bidding platform, and maintain those bids consistent with industry practices, fair competitive practices and the DTE Energy Confidentiality Policy GV11.
- Evaluate each proposal against any minimum or threshold criteria. Depending on the number of submittals that meet the threshold evaluation criteria, and the type of product being sought, the Company may then rank the proposals based on bid score for further evaluation.
- Evaluate the proposals selected for further review as follows:

- If necessary, the Competitive Procurement team will develop a list of clarifying questions required to adequately complete the reviews.
- Subject matter experts from outside the Competitive Procurement team may be asked to review specific sections.
- Bids will be ranked based on ratings and weightings of the evaluation criteria.
- From this ranking, a smaller subset of supplier proposals may be selected, or "short listed" for further evaluation. It is at this point that subject matter experts may be requested to participate in technical due diligence activities for projects that will transfer ownership to the Company or be owned by the Company.

Q54. How did the Company account for the contracted OACS and Google demand in this IRP's renewable resource planning?

A54. The Company's base load forecast incorporates the contracted load associated with OACS, as well as the load for Google, which is currently pending a Commission order in Case No. U-22058. The IRP starting point also includes renewable resource planning assumptions associated with those loads, as further described by Witness Manning and discussed earlier in my testimony. As Witness Manning explains, inclusion of the OACS renewable resource assumptions in the starting point does not constitute Commission approval of specific projects or establish that particular projects are directly or exclusively assigned to OACS.

Q55. Have you calculated the incremental renewable-related amounts associated with the OACS and Google loads?

Line No.

A55. Yes. I calculated the incremental renewable-related PSCR and potential surcharge amounts associated with the OACS and Google loads that are estimated to be borne by customers other than OACS and Google. These amounts reflect the applicable renewable-related costs after accounting for the amounts estimated to be recovered from OACS and Google based on their forecasted load shares. I provided the resulting amounts to Witness Machi.

Witness Machi incorporates these amounts into her analyses of average rate impacts by customer class and energy burden for the PCA comparisons with and without OACS and Google, per the applicable directives in the Commission's December 18, 2025 Order in Case No. U-21990.

Q56. Does this complete your direct testimony?

A56. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JASON R. KUPSER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JASON R. KUPSER

Line No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name is Jason R. Kupser (he/him/his). My business address is One Energy Plaza, Detroit, Michigan, 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Wayne State University with a Bachelor of Arts degree in Public Relations in 1998. In 2013, I graduated from Wayne State University with a Master of Business Administration.

Q4. What is your professional experience?

A4. In 1999, I joined Detroit Edison and held several individual contributor roles in the Customer Service and Electric Marketing departments.

In 2009, I continued my career in the Energy Optimization (EO) department. In this department, I held individual contributor positions that were responsible for: program management of several residential programs; cost-effectiveness testing; energy savings tracking database administration; business intelligence analytics; providing various reporting functions; and special projects as needed.

In 2014, I became the Principal Supervisor of the EO Evaluation, Measurement and Verification (EM&V) staff. My primary job responsibilities included team leadership and facilitating the many interactions between DTE Energy and its independent evaluator. Other responsibilities included support of the Michigan Energy Measures Database (MEMD) calibration efforts and actively engaging with the State of Michigan EO Collaborative.

In 2016, I was promoted to Manager of Residential programs, EO, now referred to as Energy Waste Reduction (EWR). As the Manager of the Residential EWR programs, I was responsible for development of residential and low-income electric and gas product offerings that supported DTE Energy's overall energy efficiency program strategies. In 2017, I also assumed responsibility for managing the EWR Education team, which supports broader communications objectives related to promoting and educating customers about energy efficiency.

In 2019, my responsibilities changed to manage the EWR Strategy, EWR EM&V, and Demand Response (DR) teams. In 2022, I took part in an approximate one-year developmental assignment in DTE Electric's Distribution Operations department. In 2023, I resumed management of the EWR Strategy, EWR EM&V, and briefly the DR teams. The EWR Pilots team also began reporting to me at this time.

Q5. What are your current duties and responsibilities?

A5. I currently have overall responsibility for the strategic development and planning of EWR programs. My responsibilities also include ensuring EWR program cost-

effectiveness, overseeing program evaluation, and managing the EWR Pilots and EWR Education teams.

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. Yes. I am a member of the Association of Energy Services Professionals (AESP). AESP is an organization that provides professional development programs, a network of energy practitioners, and supports the transfer of knowledge and experience to promote energy efficiency programs. I am a member of the Consortium for Energy Efficiency (CEE), specifically engaging in its portfolio advisory committee. CEE is the United States and Canadian consortium of gas and electric efficiency program administrators whose goal is to accelerate the development and availability of energy efficient products and services. I am a member of the Midwest Energy Efficiency Alliance (MEEA) specifically engaging in its utility leadership group. MEEA defines itself as "…a collaborative network, promoting energy efficiency to optimize energy generation, reduce consumption, create jobs and decrease carbon emissions in all Midwest communities."

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in the following cases:

U-16358	2009 DTE Electric EO Reconciliation
U-16289	2009 DTE Gas EO Reconciliation
U-16671	2011 DTE Electric Biennial Review and Amended EO Plan
U-16730	2011 DTE Gas Biennial Review and Amended EO Plan

Line No.		
1	U-17049	2012 DTE Electric Amended EO Plan
2	U-17050	2012 DTE Gas Amended EO Plan
3	U-18262	2018-2019 DTE Electric EWR Plan
4	U-18268	2018-2019 DTE Gas EWR Plan
5	U-18332	2016 DTE Electric EO Reconciliation
6	U-18338	2016 DTE Gas EO Reconciliation
7	U-20029	2017 DTE Electric EWR Reconciliation
8	U-20035	2017 DTE Gas EWR Reconciliation
9	U-20366	2018 DTE Electric EWR Reconciliation
10	U-20369	2018 DTE Gas EWR Reconciliation
11	U-20373	2020-2021 DTE Electric EWR Plan
12	U-20429	2020-2021 DTE Gas EWR Plan
13	U-21322	2024-2025 DTE Electric and DTE Gas EWR Plan
14	U-21558	2023 DTE Electric and DTE Gas EWR Reconciliation
15	U-21672	2024 DTE Electric and DTE Gas EWR Reconciliation
16	U-21681	2026-2029 DTE Electric and DTE Gas EWR Plan
17	U-22011	2025 DTE Electric and DTE Gas EWR Reconciliation

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to:

1. Provide an overview of DTE Electric's current EWR programs;
2. Describe the Company's EWR performance in terms of energy savings, and program costs for the period 2009-2025;
3. Describe the inputs and considerations used to create EWR savings levels used in the Company's 2026 Integrated Resource Plan (IRP); and
4. Describe the EWR levels considered in the Company's IRP.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-12	Energy Savings and Costs Potential by End-Use
A-12.1	Projected Energy Waste Reduction Savings and Spend

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes.

Q11. Did you provide inputs to the group responsible for conducting the integrated resource planning process?

A11. Yes. As supported by Witness Manning and discussed later in my testimony, I provided information on EWR levels considered in the 2026 IRP.

Line No.

Q12. Can you describe how your testimony is organized?

A12. Yes. My testimony consists of the following five (5) parts:

Part I	EWR program overview
Part II	EWR performance for the period 2009-2025
Part III	EWR assumptions and inputs used in the 2026 IRP
Part IV	EWR levels considered in the 2026 IRP
Part V	EWR costs for pre-approval

Part I: EWR Program Overview

Q13. What is the purpose of the Company's EWR program?

A13. As a result of the Clean, Renewable, and Efficient Energy Act, also known as 2008 Public Act (PA) 295, DTE Electric developed energy efficiency programs to encourage customers to save energy. These EWR programs focus on increasing awareness and adoption of energy-saving technologies to reduce overall energy use. This is accomplished by providing products and services such as rebates, tips, tools, strategies, and energy efficiency education to help customers make informed energy saving decisions.

Two PA 295 legislation amendments were signed into law, PA 342 in 2016 and PA 229 in 2023. The most recent amendment, PA 229, established a new EWR minimum energy savings standard of 1.5% of a utility's total retail electricity sales of the preceding year, with an average life of at least eight years for energy waste reduction measures.

Q14. How often are EWR plans filed and reconciled with the MPSC?

A14. In accordance with PA 295, as amended, EWR plans are filed every four years. However, when the Company receives a final order on an IRP, the Company shall file a new EWR plan within eight months after receiving that order.

EWR plans are reconciled with the Commission every year and assure energy savings and spending meet the requirements of the law and stated objectives. The Company's most recently concluded EWR reconciliation, Case No. U-21672, includes results from the 2024 program year and the EWR reconciliation of 2025, Case No. U-22011, is currently in proceedings.

Q15. Does the Company anticipate filing a new EWR plan as a result of the order from this IRP case?

A15. Yes. In accordance with PA 295, as amended, the Company will file its next EWR Plan within eight months of the final order in this case, which is expected in the fall of 2027. The Company expects that filing to be a four-year EWR Plan for plan years 2029 through 2032.

Q16. What is the current status of the Company's EWR program?

A16. The Company has evolved its EWR program since the initial 2009 launch by expanding the scope of existing programs and adding and removing program options to the portfolio. DTE Electric's EWR program has historically exceeded the energy saving standards defined in PA 295, as amended. The Company is currently delivering energy efficiency programs as described in its 2026-2029 EWR plan, Case No. U-21681, which was approved by the MPSC on January 15, 2026.

As a result of the 2022 IRP, Case No. U-21193, DTE Electric agreed in settlement to sustain an EWR target of 2.0% of the preceding year's forecasted sales through 2027. At the time the Company filed the 2026-2029 EWR plan, the load forecasts used did not include any load from hyperscale data centers because the Company did not have a contract to serve any data centers at the time of the filing. The Company's 2026-2029 EWR plan was designed to comply with the 2022 IRP settlement, continue exceeding the minimum energy savings standards, and target annual savings equal to 2.0% of DTE Electric's preceding year forecasted sales for each year from 2026 through 2029, based on the forecasts at that time.

Q17. Can you summarize the Company's EWR program offerings?

A17. Yes. The Company's EWR programs include offerings available through Residential Programs, Income-Qualified Programs, Health and Safety Programs for income-qualified customers, Commercial and Industrial Programs, Workforce Development Programs, Pilot Programs, and Education and Awareness Programs. In addition to the program offerings, DTE Electric's EM&V effort verifies net energy savings reported by the commercialized EWR programs. The programs are managed by DTE Electric program managers and operated by expert implementation contractors, primarily utilizing local labor and products.

Each program offers a combination of EWR products, services, customer incentives, rebates, and education. The following is an overview of each program category:

- Residential Programs offer customers products, services, and rebates encompassing appliance recycling; weatherization; ENERGY STAR®

Line No.

appliances; water heating, heating, ventilation, and air conditioning (HVAC); new construction, multifamily; behavioral programs; school programs; and online marketplace.

- Income-Qualified Programs reduce the energy use of the Company's income-qualified customers through improvements to their existing home at no direct cost to them. The Income-Qualified program meets its objectives through single family, multifamily, new construction, and schools sub-program offerings.
- Health and Safety Programs are for income-qualified customers to address structural repair and/or home repair needs that are barriers to the installation of energy efficiency measures through the Company's single family and multifamily income-qualified sub-programs.
- Commercial and Industrial Programs offer businesses products; services and prescriptive rebates for specific equipment replacement such as lighting, boilers, pumps, and compressors; custom programs provide rebates per kilowatt hour (kWh) of electricity savings for a comprehensive system or industrial process improvement; small business programs; operational programs; and distributor engagement.
- The Workforce Development Program offers training and mentorship initiatives, with an emphasis on equity and inclusion, to bolster participating trade contractor engagement and growth in the energy efficiency industry. The Workforce Development Program continues to promote the value of energy efficiency and develop training designed to encourage growth of participation in the Company's EWR programs.
- Pilot Programs focus on new and emerging experimental programs to fit

longer-term portfolio needs, test the cost-effectiveness of new technologies, assess customer adoption of new technologies, and market acceptance of existing technologies using new approaches.

- Education Programs are designed to raise customer EWR awareness to help save energy and reduce energy costs. A secondary objective is to raise awareness of the various channels for customers to engage in specific EWR programs offered through the Company's website and other social media platforms.

EWR programs require independent verification of the utility claimed energy savings. This work is completed by an independent EM&V contractor in accordance with industry standards. The EM&V process is also guided by input from the Evaluation Workgroup of the MPSC EWR Collaborative.

Q18. How can the Company's EWR programs assist income-qualified customers experiencing higher energy burdens?

A18. The Company's Income-Qualified Programs provide eligible customers with improvements to their homes at no cost, including through single family, multifamily, new construction, and schools subprogram offerings. The Company also offers Health and Safety Programs for income-qualified customers to address home repair needs that may prevent the installation of energy efficiency measures. These programs and measures can reduce participating customers' energy use and thereby help mitigate higher energy burdens, including for eligible customers whose energy burden is above or below 6%.

Line No.

Part II: EWR Performance for the Period 2009-2025

Q19. Please describe the Company's progress towards delivering EWR savings since 2009.

A19. Since the portfolio's inception in 2009, the Company has provided robust EWR programs to help customers reduce energy waste. The Company refined its programs over the years to target increasing energy savings levels from 0.3% in 2009 to 1.15% in 2016. The Company increased the level of energy savings targets to 1.4% in 2017, and 1.5% in 2018 and 2019 as part of its commitment to reduce customer energy waste. The Company has further expanded its commitment by increasing the energy savings target to 1.67% in 2020 and 2.0% in 2021 as part of the Company's IRP approved in Case No. U-20471. From 2022 through 2025, the Company has targeted and sustained the goal of electric energy savings at 2.0%.

Q20. What is the Company's EWR performance from 2009 through 2025, including and excluding energy savings from Pilot, Education and Health and Safety programs (Non-standard Programs)?

A20. Table 1 below details the Company's 2009-2025 EWR program performance. Columns 2 through 5 show the performance with the inclusion of energy savings from Non-standard programs and Columns 6 through 9 show the performance excluding energy savings from Non-standard programs. Columns 2 and 6 show the annual verified net energy savings (MWh) for 2009 through 2025. Columns 3 and 7 provide the annual percent energy savings per year. Columns 4 and 8 provide the annual spend (including the financial performance incentive) for 2009 through 2025. Lastly, Columns 5 and 9 provide the dollars per first year MWh saved.

Line No.

Table 1: Annual Energy Savings, Annual % Savings, and Spend

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Including Non-standard Programs Energy Savings				Excluding Non-standard Programs Energy Savings			
Year	Annual Verified Net Energy Savings (MWh)	Annual % Energy Savings	Spend ($MM) [3]	$[3]/MWh ($)	Annual Verified Net Energy Savings (MWh)	Annual % Energy Savings	Spend ($MM) [3]	$[3]/MWh ($)
2009	202,718[1]	0.42%	$23	$114	197,646[1]	0.41%	$23	$117
2010	402,995[1]	0.89%	$47	$118	382,937[1]	0.84%	$47	$124
2011	519,262[2]	1.15%	$65	$125	480,732[2]	1.06%	$65	$135
2012	610,655	1.34%	$80	$131	555,346	1.22%	$80	$144
2013	613,527	1.30%	$86	$140	571,268	1.21%	$86	$151
2014	681,638	1.42%	$97	$143	639,701	1.33%	$97	$152
2015	620,850	1.28%	$100	$161	576,853	1.19%	$100	$174
2016	630,920	1.31%	$102	$162	585,074	1.22%	$102	$174
2017	761,630	1.57%	$110	$145	716,408	1.48%	$110	$154
2018	727,907	1.55%	$128	$176	671,255	1.43%	$128	$191
2019	717,072	1.53%	$130	$182	661,804	1.41%	$130	$197
2020	769,790	1.67%	$155	$201	703,154	1.52%	$155	$220
2021	944,217	2.06%	$217	$230	861,123	1.88%	$217	$252
2022	886,840	2.00%	$210	$236	807,264	1.82%	$210	$260
2023	957,898	2.16%	$215	$224	877,808	1.98%	$215	$245
2024	918,741	2.07%	$240	$261	828,932	1.87%	$240	$289
2025[4]	912,017	2.06%	$256	$281	822,658	1.86%	$256	$312

[1]Audited Gross Savings [2]Verified Gross Savings [3]Includes financial performance Incentive [4]2025 EWR Reconciliation Pending

Q21. Why is it important to understand EWR program performance excluding Non-standard programs energy savings?

A21. The energy savings from Non-standard programs have been historically included in DTE Electric's EWR savings accomplishments. On February 8, 2024, in Case No. U-21567, the Commission ordered that energy savings from Non-standard programs may not be counted toward targets established in IRP filings. The savings that are being proposed in this IRP filing will not include energy savings from Non-

standard programs. Therefore, to keep EWR performance comparisons equivalent over time, the Company has presented EWR performance with and without Non-standard Programs.

Part III: Inputs and considerations used to create EWR savings levels used in the 2026 IRP

Q22. Can you list and generally describe the inputs used to create the EWR savings levels for the 2026 IRP?

A22. Yes. DTE Electric used several inputs to create the savings levels that were used in the 2026 IRP. The MPSC contracted a third-party company, NV5, to conduct the 2025 Energy Waste Reduction, Demand Response, and Efficient Electrification Statewide Potential Study[1] (2025 Statewide Potential Study). DTE Electric also contracted with NV5 to provide a variation of the Statewide Potential Study specific to DTE Electric's service territory (DTE Electric Potential Study). The Company asked that NV5 make certain considerations between the two studies, which I will explain further in my testimony. The DTE Electric Potential Study served as a foundation and was used in the development of the EWR savings levels for the 2026 IRP. DTE Electric reviewed historical EWR program delivery, as found in its annual EWR reconciliation cases, which have been reviewed and approved annually by the MPSC. Reviewing past performance provides historical context regarding the Company's program maturity and levels of EWR delivery. DTE Electric also considered the current EWR 2026-2029 Plan, which the MPSC approved on January 15, 2026. Reviewing the current approved EWR plan provides further considerations of expected levels of EWR savings.

[1] 2025 Energy Waste Reduction Demand Response and Efficient Electrification Statewide Potential Study

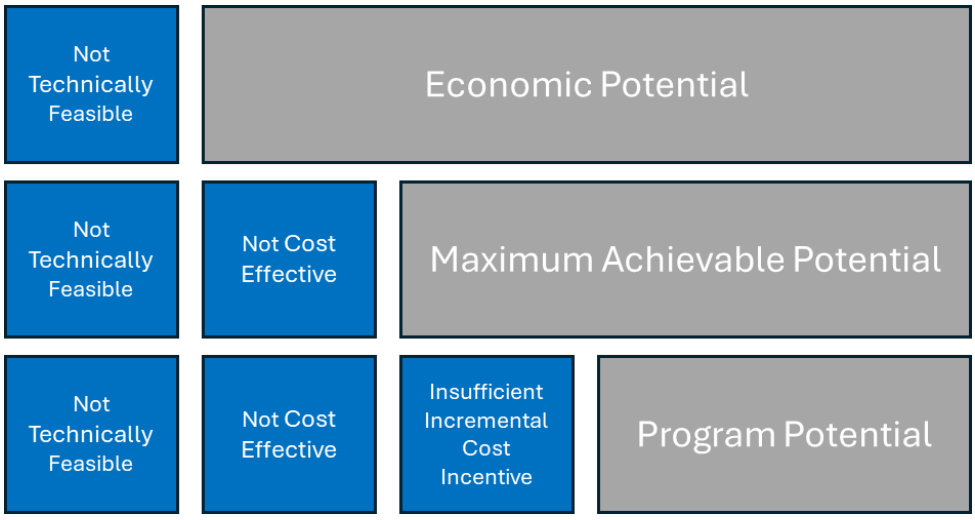
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Q23. Can you describe the 2025 Statewide Potential Study the MPSC commissioned on behalf of the State of Michigan?

A23. The MPSC commissioned the 2025 Statewide Potential Study to evaluate the potential energy savings in its service territory. Pursuant to PA 341 Section 6t (1), the MPSC must periodically assess the potential for EWR in the state to support potential modeling assumptions used by electric utilities in IRPs. In 2025, the MPSC engaged NV5 to prepare the 2025 Statewide Potential Study for electricity and natural gas in the Michigan Lower and Upper Peninsulas over a 20-year forecast horizon from 2026 to 2045.

The 2025 Statewide Potential Study distinguishes between several types of savings potential including economic potential, maximum achievable potential, and program potential. Figure 1 provides a graphical representation of the relationship of the various definitions of EWR potential.

Figure 1 : Types of Energy Efficiency Potential



Q24. What was the objective of the Energy Waste Reduction portion of the 2025 Statewide Potential Study?

A24. The 2025 Statewide Potential Study's objective was to assess a wide range of electric and natural gas energy efficiency technologies and their application to the Michigan building stock and new construction in the 2026−2045 timeframe. The study assessed the potential in the residential, income-qualified, commercial, and industrial sectors, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. NV5 used measure and market characterization data to calculate economic, maximum achievable, and program potential across utility service areas in Michigan for more than 1,200 measure permutations. The results are intended to inform EWR goal setting and associated program design for the MPSC.

Q25. How did NV5 categorize the energy efficiency measures by adoption opportunity?

A25. NV5 separated the potential of measure adoption into three specific categories: replacement, new construction, and retrofit. Replacement opportunities occur when a customer is already planning to replace equipment because it has failed or reached the end of its useful life. New construction efficiency opportunities are incorporated into new buildings or major renovations. Retrofit opportunities are when measures are installed in existing buildings before a replacement is necessary.

Q26. Why did the Company also contract with NV5 to conduct the DTE Electric Potential Study?

A26. The Company contracted with NV5 for the DTE Electric Potential Study to provide more specific data for DTE Electric's service territory. This approach also ensures methodological consistency and alignment with the 2025 Statewide Potential Study. Using the same firm promotes comparability of results, reduces duplication of effort, and supports a cohesive approach to energy efficiency planning across both state and utility levels. The DTE Electric Potential Study had very similar objectives to the 2025 Statewide Potential Study.

Q27. What were the differences between the 2025 Statewide Potential Study and the DTE Electric Potential Study?

A27. The DTE Electric Potential Study largely aligned with the 2025 Statewide Potential Study, with some differences. The differences, relevant to the electric EWR portion of the study, included the Company providing supplemental data to NV5, updating several assumptions, and extending the time frame to 2050. The supplemental data included updated avoided cost information from the DTE Electric 2026-2029 EWR plan filing, DTE Electric 2024 EWR incentive cost percentages and totals, and additional historical EWR data. Other differences included removing greenhouse gas emission benefits from the utility cost test results, making it a traditional utility cost test; using DTE Electric 2024 program data to estimate non-incentive program costs relative to incentive costs; updating appliance and equipment saturations and existing equipment efficiency data to align with DTE Electric's service territory (as opposed to the broader Lower Peninsula region assessed in the 2025 Statewide

Potential Study); and updating the energy savings for refrigerator and freezer recycling per the 2025 Statewide Appliance Recycling Calibration Study.

Q28. Would it be appropriate for DTE Electric to use the NV5 potential estimates of the DTE Electric Potential Study directly in the IRP without adjustment?

A28. No. Potential studies are an important planning tool, but they are not a prediction of future outcomes. The studies depend on informed assumptions about customer adoption, market conditions, equipment turnover, and other factors that are inherently uncertain. Actual program delivery provides direct evidence regarding how customers respond to program offerings in the marketplace. Therefore, it is reasonable and prudent for the Company to consider historical participation, realized savings, and operational experience when evaluating potential study results. For the DTE Electric Potential Study, the Company provided NV5 actual program participation data for use in its potential study modeling. However, NV5 did not properly adjust the potential to reflect this. Incorporating actual program performance helps avoid overstating achievable savings and results in a more realistic and reliable forecast for resource planning purposes.

Q29. Please describe your review of the DTE Electric Potential Study.

A29. DTE Electric conducted a detailed review of the DTE Electric Potential Study to evaluate the relationship between the savings identified in the study and the Company's demonstrated ability to deliver energy efficiency programs at levels appropriate for inclusion in the IRP. This review focused on ensuring that modeled savings used in the IRP reflect achievable outcomes grounded in actual program performance, customer adoption behavior, and market maturity.

Q30. How did DTE Electric approach the evaluation of the DTE Electric Potential Study results?

A30. As part of the evaluation, the Company segmented the DTE Electric Potential Study results into key end-use categories relevant for energy efficiency savings level development. These categories were prioritized based on their contribution to total portfolio savings across all incentive tiers. The end-uses reviewed collectively represent approximately 70% of the total energy savings identified in the DTE Electric Potential Study and include residential appliances, residential whole home, residential HVAC cooling and heating, commercial lighting, industrial lighting, and industrial machine drive.

Q31. What is an end-use?

A31. An end-use is a categorization of equipment or services that are similar to each other in purpose and timing of energy savings (e.g., lighting, refrigeration, heating, cooling, etc.).

Q32. Please summarize the DTE Electric Potential Study results for the residential appliance end-use category.

A32. The residential appliance category included significant savings potential from appliance recycling well above what DTE Electric has actually achieved in practice. DTE Electric has implemented an appliance recycling program continuously since 2009 and this program has reached a mature, steady-state level of participation. Historical program data indicates that appliance recycling adoption has plateaued and does not support the higher measure recycling levels assumed in the NV5 study. The NV5 identified savings potential implies an average potential measure for

recycling of approximately 44,000 dehumidifiers, 33,000 freezers, and 30,000 refrigerators per year. In contrast, the Company's historical experience shows total appliance recycling of approximately 36,000 appliances in total per year.

Q33. How were the residential appliance end-use category findings reflected in the IRP savings levels?

A33. To align with demonstrated program performance and avoid overstating achievable savings, the Company held appliance recycling savings constant over the IRP planning horizon. This approach reflects market saturation by comparing future savings opportunities against historical program performance. It is also consistent with regulatory expectations that projections be based on empirical evidence rather than theoretical potential.

Q34. Please summarize the DTE Electric Potential Study results for the residential HVAC cooling and heating end-use categories.

A34. The residential HVAC cooling and heating end-uses both include heat pump adoption. Additionally, the HVAC cooling end-use category includes savings from room air conditioner recycling and high-efficiency central air conditioning. While these measures are actively offered in the Company's programs, observed participation levels have been below those assumed in the DTE Electric Potential Study.

Q35. How did the Company adjust residential heat pump savings for the IRP?

A35. The savings were adjusted to reflect actual EWR program delivery levels, and future savings were escalated using the growth rates identified in the DTE Electric Potential Study. This approach anchors projections in demonstrated performance while preserving forward-looking market trends.

Q36. What additional considerations did the Company identify related to residential heat pump measures?

A36. DTE Electric's review found that approximately 78% of NV5's heat pump potential savings are associated with replacement opportunities, which require an existing heat pump to be replaced. However, air source heat pump saturation in the Company's service territory is at most 4.1%, resulting in an estimated annual replacement pool of approximately 5,500 units. NV5's implied air source heat pump replacements are approximately 6,000 units, which exceeds the entire estimated replacement pool.

Q37. How did the Company adjust residential room air conditioner recycling savings for the IRP?

A37. For room air conditioner recycling, the Company held savings constant based on current program delivery levels due to the same program maturity considerations described regarding the residential appliance end-use category. NV5's identified savings potential imply room air conditioner recycling of more than 160,000 units per year. Based on historical data and program projections, DTE Electric expects room air conditioner recycling to be approximately 2,500 units per year.

Line No.

Q38. How did the Company adjust residential central air conditioning savings for the IRP?

A38. For central air conditioning savings, the starting point was adjusted to reflect current EWR program delivery levels, and future savings were escalated using the growth rates identified in the DTE Electric Potential Study.

Q39. What considerations did the Company identify related to residential central air conditioning measures?

A39. The Company's central air conditioning program is mature, having been offered since 2009. Residential central air conditioning represents a replace-on-failure market, meaning customers rarely retire functioning equipment solely to achieve energy savings due to the significant upfront cost and long useful life of these systems. Instead, replacement activity is largely driven by equipment failure or end-of-life retirement. Consequently, achievable savings potential is tied to organic equipment turnover rates, with program influence occurring primarily when customers make replacement decisions following system failure.

NV5's assessment in the DTE Electric Potential Study implied central air conditioner replacement volumes of approximately 31,000 per year. Historically, the Company's program has seen participation of approximately 10,000 per year. Benchmarking participation rates for central air conditioner participation from mature programs are typically between 3–8%. The Company's adjustment reflects approximately 11% participation, which is even higher than the 3–8% range observed in comparable mature programs. NV5's approximate 35% implied participation is well above published benchmarks.

Q40. Please describe the findings of the DTE Electric Potential Study results for the residential whole home end-use category.

A40. The whole residential category includes measures such as Home Energy Reports. The Company determined that the savings identified in the DTE Electric Potential Study for this category were reasonably aligned with achievable outcomes based on program experience and industry benchmarks.

Q41. Did the Company make any adjustments to the residential whole home end-use category?

A41. No. The savings were not adjusted, as they were considered reasonable and supportable for IRP planning purposes.

Q42. Please describe the findings of the DTE Electric Potential Study results for the commercial and industrial lighting end-use categories.

A42. Commercial and industrial lighting collectively account for approximately 31% of the total savings identified in the DTE Electric Potential Study. These measures represent well-established and mature program offerings with strong historical performance.

Q43. Did the Company make any adjustments to the commercial and industrial lighting end-use categories?

A43. No. The savings levels identified in the DTE Electric Potential Study were consistent with recent performance observed in the Company's commercial and industrial lighting programs, and therefore no adjustments were made. Retaining these values ensures consistency with demonstrated delivery capability.

Q44. Please summarize the DTE Electric Potential Study results for the industrial machine drive end-use category?

A44. The industrial machine drive end-use category represented approximately 13% of the potential identified in the DTE Electric Potential Study. This category includes broadly defined measures such as compressed air improvements, machine drives, process heating, and other industrial process uses. Beyond the general description provided in the Statewide Potential Study, the DTE Electric Potential Study presented these measures at a high level and without detail. NV5 also stated in the Statewide Potential Study that "industrial sector potential is notoriously difficult to quantify and forecast due to bespoke opportunities that vary widely by industry and customer type."

Q45. How did the Company adjust savings for the industrial machine drive end-use category for the IRP?

A45. The Company conducted an additional review to better understand the applicability and deliverability of these measures. This review included comparing the savings levels identified in the study to savings achieved through current programs for measures within this end-use category. Based on that evaluation, the Company determined that the study results exceeded levels supported by actual program experience. Accordingly, the Company adjusted the savings to align with realized program delivery and escalated future savings using NV5's growth assumptions. This approach provides projections that are grounded in actual experience while still reflecting reasonable future growth.

Q46. What overarching principles guided the Company's adjustments to the DTE Electric Potential Study?

A46. The Company's adjustments were guided by the need to ensure that IRP inputs are realistic, evidence-based, and achievable. This included aligning projections with demonstrated program performance and accounting for customer adoption trends and market maturity. By anchoring savings in empirical data from DTE Electric's service territory while maintaining reasonable growth assumptions, the Company developed EWR savings levels that provide a credible foundation for long-term resource planning.

Q47. Can you briefly summarize the information in Exhibit A-12?

A47. Yes. Exhibit A-12 provides a summary of the DTE Electric identified EWR potential by end-use categories.

Page 1 displays the energy savings potential and related cost by end-use, assuming incentive levels set at 100% of incremental cost. Lines 1 through 19 show the Electricity Incremental Annual Achievable Potential (MWh, net at meter). Lines 20 through 38 show the Weighted Average Electricity Measure Life. Lines 39 through 57 show the Electric Program Bundle Incentive $ / First Year MWh Saved. Lines 58 through 76 show Electric Program Bundle Implementation $ / First Year MWh Saved.

Page 2 displays the potential and related cost by end-use, assuming incentive levels set at 50% of incremental cost. Lines 1 through 19 show the Electricity Incremental Annual Achievable Potential (MWh, net at meter). Lines 20 through 38 show the Weighted Average Electricity Measure Life. Lines 39 through 57 show the Electric

Line No.

Program Bundle Incentive $ / First Year MWh Saved. Lines 58 through 76 show Electric Program Bundle Implementation $ / First Year MWh Saved.

Q48. How did the Company model EWR savings based on the identified program potential?

A48. The Company modeled EWR savings by end-use, with an objective to achieve savings goals at the lowest cost, with some guardrails of savings minimums and maximums. Modeling by end-use provides a more accurate analysis of EWR as a resource than relying on levelized averages and allows the Company to better identify and value the impact of EWR adoption. This approach also enables the Company to use end-use load shapes, develop more accurate cost assumptions, and calculate lifetime savings benefits more accurately.

The end-uses modeled in the IRP are listed in Table 2 below:

Table 2: End-Use Categories

Residential End-Uses	Commercial End-Uses	Industrial End-Uses
Appliance	Cooking	Lighting
HVAC Cooling	HVAC Cooling	Refrigeration
HVAC Space Heating	HVAC Space Heating	Machine Drive
Lighting	Lighting	Whole Building
Other	Other	
Water Heating	Water Heating	
Whole Home	Whole Building	
	Refrigeration	

Q49. Did the Company account for both Installation Rate Adjustment Factors (IRAF) and Net-to-Gross (NTG) adjustments in developing the DTE Electric identified EWR potential?

A49. Yes. The DTE Electric Potential Study already accounted for NTG adjustments (EWR savings that are attributed to the program) but did not include IRAF (EWR measures that are operating as intended). Therefore, DTE Electric applied IRAF values to the identified incremental annual savings potential to calculate the potential net verified EWR savings available for each end-use. NTG adjustments account for free-ridership, where a customer would have taken the efficient action without the EWR program, and spillover, where additional efficient actions are taken because of the EWR program. IRAF accounts for measures that may be removed, never installed, or not operating as expected. DTE Electric used the most recent IRAF values available at the time of model development, as determined by the Company's third-party evaluator. Applying IRAF better reflects the annual incremental savings that serve as the basis for EWR Plan filing targets, which more accurately represent how these savings are seen in the field.

Q50. How did the Company estimate the measure life of energy savings identified in the DTE Electric Potential Study?

A50. Estimated measure life represents the number of years that EWR equipment is expected to operate or energy-efficient behavior is expected to persist. Similar to supply-side resources, energy efficiency resources have a finite life; for example, light bulbs burn out, HVAC equipment must be replaced, and water heating systems eventually require replacement. NV5 provided the measure life for each measure

in the DTE Electric Potential Study, which were the same values used in the Statewide Potential Study.

Exhibit A-12 provides the weighted average measure life. A weighted average measure life is calculated by multiplying each measure's expected life by its associated energy savings, summing those values across all measures, and dividing by total first-year energy savings. These values were calculated for all seven residential end-uses, all eight commercial end-uses, and all four industrial end-uses. The Company used these weighted average measure lives for each end-use, by year, to calculate lifetime savings. This approach allows the Company to capture changes in measure mix over the IRP planning period and more accurately account for the cumulative impact of EWR savings.

Q51. Did the Company consider the load shape of EWR measures when developing hourly savings units?

A51. Yes. For residential, commercial and industrial end-uses, the Company used load shapes developed for integration in the MEMD. The Company used the end-use load shapes to determine hourly savings units, creating an 8,760-hour savings shape for each end-use. The Company then aggregated the end-use savings shapes to develop a combined EWR savings shape that could be used in IRP modeling.

Q52. Did the Company include line losses in its modeling of EWR savings?

A52. Yes. Since EWR savings are modeled by end-use, the savings were increased to account for distribution losses when the 8,760-hour savings shapes were developed. The Company used an average marginal line loss of 10.47% and peak marginal line

loss of 27.22%. The marginal line loss rate calculations were provided by Guidehouse and based on November 2021 Burns & McDonnell line loss estimates for DTE Electric's system.

Q53. What are EWR end-effects?

A53. EWR end-effects account for the benefits of EWR that occur after the IRP study period ends. Although the full cost of EWR measures is reflected within the IRP timeframe, some benefits extend beyond that period because EWR technologies continue producing savings over their useful lives. EWR end-effect values represent the portion of benefits that occur outside of the IRP timeframe.

Q54. Did you provide any inputs for EWR end-effects to the IRP team?

A54. Yes. For each EWR level (as described in Part IV of my testimony), DTE's IRP team was provided with the total present value (PV) of benefits over the full life of the applicable end-uses, as well as the PV of benefits occurring within the IRP study period through 2046, as discussed by Witness Manning. DSMore, the cost-effectiveness software used by the Company, produces total PV benefits over the full life of each end-use and annual benefit values for the first 25 years. The PV of benefits was calculated through 2046 and were provided to DTE's IRP team for comparison to total PV benefits. The difference between those values represents the EWR end-effects.

Q55. What data source did the Company use to model EWR costs?

A55. The Company used the underlying cost assumptions included in the DTE Electric Potential Study. The Company aggregated the total costs for each end-use to

calculate savings level costs. Exhibit A-12 provides cost per first year saved for each end-use by year.

Q56. Did the Company include any costs in its EWR modeling in addition to those provided in the DTE Electric Potential Study?

A56. Yes. The Company included additional costs for EM&V and the financial performance incentive. EM&V costs were based on the planned spend in the 2026-2029 EWR Plan and scaled for inflation. The financial performance incentive was calculated based on the applicable savings achievement level and total annual spend, consistent with PA 295, as amended.

Part IV: EWR Levels Considered in the 2026 IRP

Q57. What were the EWR levels the Company evaluated as part of its IRP process?

A57. In total, ten EWR levels were evaluated. For each level, the 2027 and 2028 program years align with the approved 2026-2029 EWR Plan. Unless otherwise specified, the EWR levels are expressed as a percentage of total annual retail electric sales, including the forecasted load from two hyperscale data centers, and include the following:

1. Base Case – The savings in 2029 aligns with the approved 2026-2029 EWR Plan. Beginning in 2030, DTE Electric used the MWh savings from the 2022 Proposed Course of Action (2022 PCA) in the 2022 IRP to set savings targets for 2030 and beyond. Beginning in 2030, costs were updated using the DTE Electric Potential Study and calculated assuming 50% of incremental cost.

Line No.

2. 1.5% – Beginning in 2029, the savings target is set at 1.5% of the preceding year's forecasted sales, calculated assuming 50% of incremental cost.
3. 2.17% – Beginning in 2029, maximizes potential until the savings target reaches 2.17% of the preceding year's forecasted sales, and then maintains that target thereafter; calculated assuming 100% of incremental cost. The Company modeled this level using the potential identified by NV5 in the DTE Electric Potential Study. These savings levels were not constrained by DTE Electric's review of deliverability for purposes of IRP inclusion.
4. 2.5% – Beginning in 2029, maximizes potential to reach a savings target of 2.5% of the preceding year's forecasted sales; calculated assuming 100% of incremental cost. The Company modeled this level using the potential identified by NV5 in the DTE Electric Potential Study. These savings levels were not constrained by DTE Electric's review of deliverability for purposes of IRP inclusion. The savings potential was not sufficient to achieve the 2.5% target.
5. Maximum with 100% incremental cost – Beginning in 2029, maximizes the DTE Electric identified potential and is calculated using incentive levels equal to 100% of incremental cost.
6. Maximum with 50% incremental cost – Beginning in 2029, maximizes the DTE Electric identified potential and is calculated using incentive levels equal to 50% of incremental cost.
7. Maximum potential through 2032, down to 1.5% – Beginning in 2029, maximizes the DTE Electric identified potential through 2032. Beginning in 2033, the savings target is set at 1.5% of the preceding year's forecasted sales. This savings level is based on the DTE Electric identified potential using incentive levels equal to 50% of incremental cost.

8. Maximum potential through 2036, down to 1.5% – Beginning in 2029, maximizes the DTE Electric identified potential through 2036. Beginning in 2037, the savings target is set at 1.5% of the preceding year's forecasted sales. This savings level is based on the DTE Electric identified potential using incentive levels equal to 50% of incremental cost.
9. 1.5% with one hyperscale data center - Beginning in 2029, models a savings target of 1.5% of the preceding year's forecasted sales with only one hyperscale data center included, based on the DTE Electric identified potential using incentive levels equal to 50% of incremental cost.
10. 1.5% with no hyperscale data centers - Beginning in 2029, models a savings target of 1.5% of the preceding year's forecasted sales with no hyperscale data centers included, based on the DTE Electric identified potential using incentive levels equal to 50% of incremental cost.

The costs and savings for the EWR savings levels are shown in Exhibit A-12.1, which is described later in testimony. This was provided to the IRP team for use in the modeling process which is further explained by Witness Manning.

Q58. Why did DTE Electric model a 1.5% EWR level that excludes hyperscale data centers from the forecasted load?

A58. The Company modeled this level to understand the end-use savings and associated costs without the forecasted load from data centers. This provides a baseline for comparing the incremental savings and cost impacts associated with including data center(s) load in the 1.5% EWR level.

Q59. Why did DTE Electric model a 1.5% EWR level that includes one hyperscale data center in the forecasted load?

A59. The Company modeled this level to understand the end-use savings and associated costs when the forecasted load from only one data center is included. The data center load included in this modeling is the forecasted load DTE Electric was approved to serve in Case No. U-21990. This level provides a basis for comparing the incremental savings and cost impacts associated with adding a second data center's forecasted load to the 1.5% EWR level that includes two data centers.

Q60. Why is it important for the IRP modeling to evaluate EWR levels with and without hyperscale data center load?

A60. Evaluating EWR levels with and without hyperscale data center load helps the Company understand the incremental savings and cost impacts associated with hyperscale data centers. This information is important because, under PA 295, as amended, a hyperscale data center may submit a self-direct energy waste reduction plan. Understanding these impacts allows the Company to assess how hyperscale data center self-direct plans may affect EWR savings requirements and associated costs in the IRP modeling.

Q61. In modeling the 1.5% EWR level, did DTE Electric assume that any portion of the savings target or related costs would be satisfied by self-directed hyperscale data center savings?

A61. No. The 1.5% EWR level includes the forecasted load from two hyperscale data centers and the associated costs needed to deliver the required energy savings, assuming no self-directed savings from those hyperscale data center customers.

Q62. How did the Company account for a hyperscale data center customer choosing to self-direct?

A62. The 1.5% EWR level includes the necessary energy savings, assuming no self-direct savings from hyperscale data center customers. To account for potential self-direct plans, the Company used the 1.5% One Hyperscale Data Center and 1.5% No Hyperscale Data Centers levels to derive the incremental cost reductions associated with one or more hyperscale data center customers choosing to self-direct.

The lower costs of the 1.5% One Hyperscale Data Center EWR level as compared to the 1.5% EWR level reflect the costs of the second hyperscale data center self-directing its EWR. Those lower costs were reflected in the IRP modeling, as discussed in the testimony of Witness Manning.

Q63. How does the Company address providing an EWR savings level that supports Scenario #1 as described in the Michigan Integrated Resource Planning Parameters U-21570 & U-21867?

A63. As discussed previously, the 2.5% EWR savings level represents the maximum achievable savings potential identified by the Company and was developed with the objective of approaching a savings target equal to 2.5% of the prior year's forecasted sales. This portfolio therefore reflects the highest level of EWR savings that the Company expects.

While the 2.5% EWR savings level does not achieve the 2.17% annual savings level assumed in Scenario #1 of the Michigan Integrated Resource Planning Parameters (MIRPP) established in Case Nos. U-21570 and U-21867, it provides the closest

achievable approximation of that level of energy savings. For the Scenario #1 sensitivity, the highest percentage of savings is at 2.08% for three years, 2038 through 2040. Additionally, for the Scenario #1 sensitivity, the average annual percentage of savings is 1.99% over the study period. Therefore, the 2.5% EWR savings level serves as the appropriate input for evaluating the Scenario #1 sensitivity within the Company's IRP.

Q64. Can you briefly summarize the information in Exhibit A-12.1?

A64. Yes. Exhibit A-12.1, lines 1 through 10, show the estimated annual savings (MWh) for each EWR level for 2027 through 2046. In the savings levels other than the Base Case, the EWR target for each level was calculated as either the percentage annual savings multiplied by the total retail electric sales from the previous year or the maximum savings identified at that incentive level. Lines 11 through 20 provide the estimated cumulative energy savings (MWh) for each EWR level for 2027 through 2046. Lines 21 through 30 provide the estimated cumulative capacity savings (MW) for each EWR level for 2027 through 2046. Lines 31 through 40 provide the total annual operational cost for each EWR level for years 2027 through 2046. Lines 41 through 50 provide the total financial performance incentive for each EWR level for years 2027 through 2046. Lastly, lines 51 through 60 provide the total annual cost for each EWR level for years 2027 through 2046.

Q65. Did the Company determine the cost-effectiveness for each level?

A65. Yes. Table 3 below provides the Utility System Resource Cost Test (USRCT) results for each EWR level. All levels show they are cost effective, as they are all greater than 1.0.

Line No.

Table 3: USRCT Benefit Cost Ratio Results

EWR Level		USRCT
1	Base Case	1.93
2	1.50%	2.22
3	2.17%	1.40
4	2.50%	1.39
5	Max 100% incremental costs	1.22
6	Max 50% incremental costs	2.10
7	Max through 2032, down to 1.5%	2.20
8	Max through 2036, down to 1.5%	2.17
9	1.5% One Hyperscale Data Center	2.29
10	1.5% No Hyperscale Data Centers	2.26

Q66. Why does the Company use the USRCT for determining cost-effectiveness?

A66. Section 73(2) of Michigan Public Act 229 of 2023 states that "[t]he commission shall not approve a proposed energy waste reduction plan unless the commission determines that the energy waste reduction plan meets the utility system resource cost test and is reasonable and prudent." Therefore, the Company uses the USRCT for determining cost-effectiveness in EWR plan filings.

Q67. Did the Company include avoided transmission and distribution (T&D) costs in its EWR cost-effectiveness testing?

A67. Yes. Witness Singh provided an estimate of the deferred T&D costs that were incorporated into the EWR cost-effectiveness testing.

Q68. What level of EWR did the Company include in this IRP's 2026 Proposed Course of Action (2026 PCA)?

A68. The Company's 2026 PCA includes the 1.5% EWR savings level throughout the IRP timeframe. However, the costs associated with savings expected to be achieved through hyperscale data center self-directed plans were removed as it is assumed that the data center customers will either self-direct or be in a unique surcharge class that covers their cost of savings. The EWR savings included in the PCA, and how the IRP modeling results were used to develop the PCA, are discussed in the testimony of Witness Manning.

Q69. How does the Company view the achievability of the energy savings levels identified in the PCA?

A69. The Company believes the assumptions included in the PCA are reasonable for planning purposes. However, the PCA is an estimate of future energy efficiency savings and, like any estimate, includes uncertainty. That uncertainty may result from changes in baseline standards, technology, forecasted avoided costs, and projected customer response and behavior. Accordingly, the Company will continue to evaluate potential energy savings in future IRP proceedings.

Q70. What challenges may affect the Company's ability to deliver EWR savings?

A70. The Company is forecasting energy savings aligned with the DTE Electric identified EWR potential at the 1.5% annual savings level throughout the IRP study period. However, achieving savings identified in the Company's identified EWR potential is expected to become increasingly difficult due to several challenges, including:

Line No.

- As shown in Table 1, Columns 5 and 9, the cost per first year MWh achieved has increased significantly over time and this trend is expected to continue as less expensive, higher energy savings measures are adopted;
- After more than 17 years of operating EWR programs, the Company has already captured the "low-hanging fruit" (e.g. residential lighting, most inefficient appliances having been recycled, low-cost direct install measures, etc.);
- Ongoing increases in baseline product efficiency, resulting from codes and standards,[2] reduce the achievable incremental savings available to utility energy efficiency programs;
- Customer baseline installed efficiency continues to rise as energy efficiency programs and other factors make customers more conscious about energy consumption; and
- Higher EWR savings targets increase program costs and add to customer affordability pressure. For example, the shift toward more commercial and industrial savings has led to significant increases in EWR surcharges for that customer segment, while relatively few customers in that segment directly benefit.

[2] U.S. Department of Energy Standards and Test Procedures, available at https://www.energy.gov/cmei/buildings/standards-and-test-procedures, last accessed September 3, 2026.

Part V: EWR Costs for Pre-approval

Q71. Is the Company requesting pre-approval of the projected costs to deliver these energy savings levels as part of this proceeding?

A71. No. Consistent with the regulatory process followed since 2009, the Company will request approval of EWR costs as part of its EWR Plans filed with the Commission following the conclusion of this case.

Q72. Will the Company refine its EWR cost projections in future EWR Plan filings?

A72. Yes. EWR Plans include details on the portfolio goals, a description of each program in the portfolio, energy savings, spend levels, cost-effectiveness test results, portfolio implementation and management details, and EM&V information.

Q73. Does the Company model or expect any of the EWR cost projections will be capital costs?

A73. No.

Q74. If there are changes that may impact the Company's ability to deliver energy savings, will the Company address these in its future EWR Plan filings?

A74. Yes. Changes to codes and standards, program costs, customer trends, evaluation studies that impact energy savings, market saturation, and other factors will be addressed as part of the Company's regular EWR filings.

Q75. Does this complete your direct testimony?

A75. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

HUSANINDER SINGH

DTE ELECTRIC COMPANY
DIRECT TESTIMONY OF HUSANINDER SINGH

Line No.

Q1. What is your full name, business address, and by whom are you employed?

A1. My name is Husaninder Singh, Manager – Subtransmission and Industrial Planning & North American Electric Reliability Corporation (NERC) Compliance. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I hold a Bachelor of Science in Electrical Engineering from Wayne State University. I also hold a Master of Business Administration from the University of Michigan.

Q4. What is your professional experience?

A4. I have more than 17 years of experience in electric utility engineering, planning, operations, and management with DTE Electric. Since joining the Company in 2008, I have held positions of increasing responsibility in distribution engineering and planning, engineering standards, system operations, distribution planning, grid modernization, regional planning, and subtransmission planning. Throughout my career, I have been responsible for electric system planning, reliability improvement initiatives, grid modernization programs, operational support, engineering standards, and the development and execution of capital investment projects supporting the Company's electric distribution and subtransmission systems.

I have served in both engineering and leadership roles supporting long-term distribution and subtransmission planning, system operations, grid modernization, and regional planning activities. My responsibilities have included evaluating system needs, supporting customer load growth, integrating emerging technologies, developing reliability improvement programs, and coordinating planning activities across multiple business units. I have also supported the development of distribution planning methodologies, forecasting initiatives, and investment strategies designed to maintain reliability while preparing the electric system for evolving customer and operational requirements.

Q5. What are your current duties and responsibilities?

A5. Currently, I am the Manager – Subtransmission and Industrial Planning & NERC Compliance and lead the NERC Compliance, Subtransmission, and Industrial Planning teams. These teams are responsible for planning and analysis of the Company's subtransmission system, planning support for industrial customers connected to the subtransmission system, and compliance management for a subset of NERC standards applicable to distribution operations.

My responsibilities include overseeing the long-term planning of the subtransmission system to ensure the continued reliability and capability of the network to meet evolving customer and system needs. This includes evaluating system performance, identifying future infrastructure requirements, and coordinating planning activities with the regional transmission planning process and transmission system operators to support the reliable operation of the electric system. I am also responsible for planning support related to industrial customers

connected to the subtransmission system. This includes evaluating and supporting new customer connections, facilitating customer load growth, assessing system impacts associated with changing customer requirements, and supporting existing customers on matters related to electric service reliability and power quality. In addition, I provide leadership and oversight for compliance activities associated with applicable NERC reliability standards within my area of responsibility.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. No. I have not sponsored testimony before the MPSC.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Explain how distribution planning is coordinated with the Company's Integrated Resource Plan (IRP);
- Describe the conservation voltage reduction/volt var optimization (CVR/VVO) assumptions and inputs that were provided to the IRP team for modeling and the amount of CVR/VVO in the Proposed Course of Action (PCA); and
- Describe the steps Distribution Operations (DO) is taking related to the peaker generation study.

Q8. How is your testimony organized?

A8. My testimony consists of three parts:

Line No.

	Part I	Planning Coordination
	Part II	CVR/VVO Program
	Part III	Distribution Operations Peaker Analyses

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-13	IRP Study Inputs on CVR/VVO Program Circuit Implementation Plan and Expected Savings
A-13.1	IRP Study Inputs on CVR/VVO Program Capital Spend

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

PART I: PLANNING COORDINATION

Q11. How has the MPSC addressed coordination among integrated resource and distribution planning?

A11. The Commission addressed this topic in its October 17, 2019 Order establishing the MI Power Grid initiative in Case No. U-20645.[1] In that Order, the Commission emphasized the need to align resource, transmission, and distribution planning around "optimizing grid investment and performance." Specifically, the Commission stated that:

[1] As explained by the Commission, MI Power Grid is a "focused, multi-year stakeholder initiative to maximize the benefits of the transition to clean, distributed energy resources (DERs) for Michigan residents and businesses. MI Power Grid seeks to engage utility customers and other stakeholders to help integrate new clean energy technologies and optimize grid investment for reliable, affordable electricity service." (p. 1, U-20645, October 17, 2019 Order).

> *"Advanced planning processes for electric investments (resources, transmission, and distribution) will be examined to ensure modeling tools, assumptions, and processes are adapting to technology change, and to better integrate discrete planning activities currently being conducted for new resources (e.g., generation, demand-side options), transmission, and distribution, as detailed in the 2019 Statewide Energy Assessment." (p. 8, Case No. U-20645, Oct. 17, 2019 order)*

Q12. What challenges has the Commission identified in coordinating these planning processes?

A12. Commenting on workshop presentations from DTE Electric, Consumers Energy, and Indiana Michigan Power Company, the Commission observed:

> *"Differences in scope, objectives, and planning horizon pose a challenge when attempting to align these processes. The traditional approach to planning also does not facilitate the level of information sharing needed to integrate resource, transmission, and distribution plans. Data availability, information technology infrastructure, personnel skill sets, and insufficient modeling tools limit alignment due to added complexities a fully integrated planning process requires." (citation omitted, p. 25-26, September 24, 2021 order in U-20633 et al.)*

Q13. What direction did the Commission provide to address these planning challenges?

A13. In Case No. U-20633, the Commission initiated a collaborative process to evaluate improvements and better align integrated resource, transmission, and distribution planning and directed Staff to file a report with findings and recommendations. In its September 24, 2021 Order, the Commission adopted Staff's recommendations that utilities: 1) increase consistency and coordinate timing across planning processes so information flows accurately and links inputs, outputs, and decisions;

2) increase communication and transparency within utility organizations and with stakeholders; and 3) treat planning as an iterative process that shows how the three planning processes affect and support one another.

The Commission subsequently incorporated and expanded these planning-coordination concepts through updates to the Michigan Integrated Resource Planning Parameters and IRP filing requirements in Case Nos. U-21570 and U-21867. Most recently, in its December 18, 2025 Order in Case Nos. U-21867 and U-21570, the Commission approved updated planning parameters and IRP filing requirements under amended MCL 460.6t, further supporting coordination among resource, transmission, and distribution planning and the consideration of distributed energy resources, demand-side resources, electrification, transmission alternatives, and other system-planning inputs. Witness Hajj discusses the updated requirements resulting from Case No. U-21867 in her direct testimony.

Q14. How has the Company implemented this direction through coordination of distribution and resource planning?

A14. The Company submitted its 2026 Distribution System Plan (DSP)[2] in April 2026, building on the foundation established in the 2023 DSP. The 2026 DSP advances shared IRP and DSP planning objectives and identifies investments necessary to enhance reliability and modernize the electric subtransmission and distribution systems. The Company also has several ongoing efforts to coordinate distribution and resource planning, including:

[2] DTE's 2026 Distribution System Plan (DSP), available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00001xy74BAAQ, accessed May 5, 2026.

- Development and use of shared customer-focused planning objectives to support collaborative processes and decision-making criteria for distribution and generation planning as discussed by Witness Hajj;
- Advancement in load forecasting methodologies and tools to support both DSP and IRP planning processes, as discussed by Witness Sirwaitis;
- Identification of investments that could provide resource capacity and distribution benefits such as the Company's proposed investments in CVR/VVO as outlined in the 2026 DSP and my direct testimony;
- Development of distribution-related inputs to support the IRP process and inform the PCA as detailed in my direct testimony, specifically:
    - input assumptions for incremental CVR/VVO
    - deferred transmission and distribution costs associated with energy waste reduction programs aggregated at system level
    - estimated distribution costs associated with new generation resources
    - estimated distribution costs associated with retirement of peaker units
- Coordination among multiple business units including Distribution Operations in the peaking generation study to better understand and quantify distribution system impacts as discussed further by Witness Pratt and in my direct testimony; and
- Improved information sharing with external stakeholders related to distribution planning topics including participation by the DSP team in IRP information sessions as discussed by Witness Hajj.

The 2026 IRP builds on these advancements by incorporating distribution planning assumptions and considerations into resource planning. Continued coordination is important to account for the effects of distributed energy resources (DERs) and electrification on both the bulk power system and localized distribution system needs.

Q15. For purposes of your testimony, how are you defining DERs?

A15. I am using the MPSC definition of DERs[3]:

> *"A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system."*

As this definition indicates, these resources could be behind or in front of the customer's meter but would be distinguished from utility-scale resources connected to the transmission system.

Q16. Why does increasing DER adoption require continued coordination between distribution and resource planning?

A16. DERs can change both system-level and localized load patterns. As adoption increases, the Company must coordinate forecasting assumptions and planning analyses, so the IRP reflects aggregate capacity and energy impacts while distribution planning reflects circuit-level impacts.

More robust forecasting will be needed to account for DER and electric vehicle (EV) impacts at both levels. On the distribution system, higher DER penetration

[3] Distribution Investment and Maintenance plan, p. 11, U-20147, August 20, 2020 Order.

and bidirectional power flows may also affect circuit load profiles and planning needs. Continued coordination between resource planning and distribution planning will help facilitate the consistent consideration of these impacts in planning analyses and the evaluation of non-wires alternatives (NWAs) as potential solutions for specific local system needs, based on technical feasibility and economic merit.

Q17. Can you discuss how the Company is improving forecasting methods and tools to prepare for increased DER adoption rates?

A17. The Company's DO team worked with the Corporate Energy Forecasting (CEF) team and developed a forecasting solution that accounts for the potential distribution grid impacts of behind-the-meter DER and EVs into the generation and distribution load forecasts informing both long-term planning of the generation and distribution systems. These forecasting advancements, introduced in Case No. U-21193 and in further detail in Case No. U-22104, support the alignment of planning processes, data, assumptions, and methodologies to enable a more consistent, integrated and scenario-based approach. Witness Sirwaitis provides additional details regarding the solution and its integration into the Company's distribution system plan in his testimony.

Q18. Will the Company continue this coordination as DER adoption and electrification increase?

A18. Yes. The Company will continue coordinating distribution and resource planning assumptions, forecasts, and analyses so changing grid conditions are reflected in both the bulk system and localized distribution levels.

PART II: CVR/VVO PROGRAM

Q19. What are CVR and VVO, and what benefits does the CVR/VVO Program provide?

A19. VVO manages voltage and reactive power on the distribution system to improve operational efficiency, maintain voltage within acceptable ranges, and reduce system losses. CVR is a VVO application that operates customer voltage within the lower portion of allowable ranges to reduce energy consumption and peak demand.

The CVR/VVO Program modernizes voltage control equipment and enables coordinated, real-time management of distribution system devices through DTE Electric's Advanced Distribution Management System (ADMS). By optimizing voltage and reactive power across the distribution system, the program supports energy savings, reduces peak demand and system losses, and improves power factor and voltage regulation.

In addition to these operational benefits, the program replaces aging capacitor controls with modern SCADA-enabled equipment, enhancing system visibility and controllability to support future integration into the CVR/VVO Program. While these enhancements improve circuit efficiency through better power factor, they do not involve voltage reduction and therefore do not provide incremental CVR relative to energy savings.

Q20. Can you describe the CVR/VVO Program the Company is pursuing?

A20. Yes. The scope of the CVR/VVO Program includes the deployment of sensing, communications, and control technologies to enable coordinated voltage reduction

and reactive power optimization across the distribution system. These capabilities are enabled through integration with the Company's ADMS, allowing for system-level, real-time control of voltage and reactive power on targeted circuits.

Key elements of the program include:

- Updating substation transformer load tap changers with remote monitoring and control capabilities;
- Installing or upgrading overhead capacitor banks with SCADA-enabled smart controllers, including CBC-8000 controllers;
- Implementing remote control capabilities for line regulators; and
- Deploying voltage and line sensors at strategic locations to provide visibility into primary voltage conditions.

In addition, the program includes implementation of the ADMS Volt-Var Control (VVC) module, which integrates field devices into a system-level, real-time voltage optimization capability across targeted circuits.

Q21. Did DTE Electric reflect the approved CVR/VVO pilot in the starting point for the 2026 IRP modeling?

A21. Yes. The demand savings associated with the CVR/VVO pilot approved in the 2019 IRP were reflected in the modeling starting point for the 2026 IRP.

Q22. How does the Company plan to scale the CVR/VVO Program?

A22. The Company is scaling CVR/VVO through a phased, multi-year deployment on eligible 13.2 kV circuits served by substations with load tap changers. The program coordinates substation load tap changers, capacitor banks, and voltage regulators

through real-time controls to increase energy and demand savings while maintaining service quality.

In 2025, CVR/VVO-related work was completed on 20 circuits. Planned 2026 work includes 5 circuits, and the Company plans to work on approximately 8 additional circuits in 2027 and 15 circuits annually from 2028 through 2046. Based on the current system configuration, approximately 300 circuits may be eligible for CVR/VVO deployment; actual deployment will depend on circuit characteristics and program prioritization.

The implementation activity described above reflects broader CVR/VVO Program work; Exhibit A-13 separately identifies the incremental circuit counts and associated savings used as inputs to the IRP.

Witness Manning used the values in Exhibit A-13 from 2028 through 2037 totaling 17 MW to be included in the capacity expansion optimization for CVR/VVO. See Witness Manning for how CVR/VVO was modeled and selected.

Q23. What level of incremental CVR/VVO demand savings and implementation activity is included in the PCA?

A23. The PCA includes an average of approximately 1.6 MW of incremental CVR/VVO demand savings per year from 2026 through 2037, totaling 18.8 MW by 2037, as shown in Exhibit A-13. That demand-savings level is maintained through the end of the study period. Implementation at selected substations and circuits would include the same key program elements described above.

Q24. What incremental CVR/VVO savings and costs are reflected in the 2026 IRP?

A24. As shown in Exhibit A-13, the CVR/VVO Program is expected to produce 18.8 MW of peak-demand reduction and 52.2 GWh of cumulative energy reduction by 2037. The exhibit also presents annual and cumulative peak-demand and energy reductions based on the midpoint of estimated savings ranges.

As shown in Exhibit A-13.1, the program is expected to require approximately $59.5 million of capital investment from 2026 through 2046, including approximately $3 million annually from 2028 through 2046, projected based on cost increases.

Q25. Is the Company requesting pre-approval of costs for the incremental CVR/VVO investments included in the PCA?

A25. No. The Company expects to continue to address cost recovery requests through the rate case process.

PART III: DISTRIBUTION OPERATIONS PEAKER ANALYSES

Q26. What role does peaking generation provide in supporting the distribution system?

A26. Peaking generation can provide localized capacity and voltage support during planned and unplanned outages. Because these units can be dispatched quickly, they help maintain service and system stability during abnormal operating conditions.

During planned outages, peaker generation units provide local system support and operational flexibility in the event of unexpected system conditions, failures or power flow changes. This support is critical to allow electrical system supervisors to confidently schedule the necessary shutdowns to perform routine maintenance, equipment replacements, and system upgrades while minimizing customer interruptions. The availability of peaker generation also supports the execution of infrastructure improvements needed to meet future reliability and capacity requirements of customers.

In certain circumstances, peaker generation units also support service restoration efforts during storms or other multiple unplanned outage events by providing local generation until normal grid configuration is restored. Without peaker generation support, the Company's ability to reliably serve certain areas during adverse system conditions could be reduced, potentially requiring additional distribution system mitigations and infrastructure investments to maintain acceptable reliability levels.

Q27. How can peaking generation support the system during planned and unplanned outages?

A27. During storms, equipment failures, or routine planned outages, peaking units may be used to mitigate equipment overloads or low-voltage conditions. For example, during a planned outage of a 120 kV transmission line or 40 kV subtransmission line, a peaking unit may be available if another 120 kV or 40 kV element is lost. Under that next-contingency condition, the unit could help prevent cascading outages.

Q28. Witness Pratt discusses the Company's evaluation of certain peaking units. What was DO's role in that analysis?

A28. As part of the 2026 IRP, the Company evaluated potential retirement scenarios for certain peaking units. After the Company identified a subset of peaking generation sites for further evaluation, DO reviewed these sites and identified those with known or potential impacts to the subtransmission system reliability and operational performance. DO performed and supported engineering studies under a range of operating and contingency conditions to identify potential reliability risks, system limitations, and mitigation needs associated with retirement of the selected units.

Q29. What analyses did DO perform to evaluate potential peaker-retirement impacts?

A29. DO conducted engineering system studies using industry-standard modeling software (PSS®E and TARA) and incorporated both individual substation load data and electric system models provided by the Midcontinent Independent System Operator (MISO). The MISO models included multiple system loading scenarios representing current and projected future peak load conditions.

Using these models, DO evaluated areas affected by the potential retirement of selected peaking generation units and studied a range of contingency scenarios to identify potential violations of the subtransmission planning criteria. The planning criteria evaluated thermal loading and voltage performance under normal system conditions (N-0), single-contingency events (N-1), and selected double-contingency events (N-2) across multiple loading scenarios. DO also evaluated

various operating conditions to assess potential operational risks and customer impacts.

The primary objective of the engineering system studies was to identify thermal, voltage, and operational issues that could result from the retirement of the generating units and absent mitigation, could adversely affect reliability or increase the risk of customer outages in those areas. For scenarios in which planning criteria violations were identified, DO developed high-level mitigation plans and associated preliminary cost estimates to address those impacts and maintain reliable system operation. These mitigation plans and cost estimates were provided as inputs to the Company's broader evaluation of potential peaker retirement scenarios, including the peaker-retirement analysis and recommendations discussed by Witness Pratt and the levelized cost-of-capacity modeling discussed by Witness Busse.

Q30. How did DO develop mitigation plans to address the impacts identified in the engineering studies?

A30. DO developed location-specific, conceptual mitigation plans to address the thermal, voltage, and operational impacts identified in the engineering studies. These plans included conceptual subtransmission and distribution system modifications that could be required to maintain compliance with applicable planning criteria and reliability requirements under the retirement scenarios evaluated.

Depending on the location and identified system limitation, the conceptual mitigation measures included upgrades or replacement of overhead conductors, underground cable, transformers, breakers, and other substation equipment. DO selected the facilities included in each plan based on the engineering study results and the facilities' contribution to the thermal, voltage, or operational limitations observed. DO used the identified mitigation measures to develop a planning-level scope and cost estimate for each retirement scenario evaluated. These scopes and estimates were then provided as inputs to the Company's broader assessment of potential peaker-retirement alternatives.

Q31. How were the planning-level cost estimates developed?

A31. The estimates were developed using the conceptual project scopes and available planning-level unit-cost assumptions, including applicable Project Management Organization (PMO) unit costs. The estimates were intended to provide a consistent, order-of-magnitude basis for comparing potential retirement scenarios and the required mitigation projects. They are not final engineering estimates and would be refined through the Company's normal engineering and project-development processes if a mitigation project advances.

Q32. What were the results of these engineering studies?

A32. The studies identified varying levels of distribution and subtransmission impacts across the potential peaker-retirement scenarios evaluated. At certain locations, as discussed above, retirement could create thermal, voltage, or operational concerns requiring mitigation to maintain compliance with applicable planning criteria and

reliability requirements. At other locations, the studies identified few or no significant impacts.

Where impacts were identified, the scope and estimate of the conceptual mitigations varied based on the specific system conditions associated with each retirement scenario. DO provided the study results, mitigation requirements, and planning-level investment estimates to support the Company's broader evaluation of potential peaker-retirement scenarios. Table 1 summarizes the estimated mitigation investments.

Table 1 Summary of High-Level DO Mitigation Estimates

Peaker Units	Connection (kV)	DTE Electric Estimate ($M)
Oliver/Wilmot	40	$14 - $105
Colfax/Hancock	40	$23 - $40
Superior	40	$9
Northeast	24/120	$9
Delray*	120	$0

**No planning criteria violations identified*

Q33. Can you provide an example of the mitigation measures identified through the analysis?

A33. Yes. For the Superior peaker-retirement scenario, the studies identified planning criteria violations that could be addressed through two conceptual projects: upgrading approximately 220 ft of underground cable and conduit and upgrading approximately 1.25 miles of overhead wire. Table 2 summarizes the planning-level scope and estimate for each project.

Table 2 Mitigation Projects: Superior CTG11 Decommission

Violation Type	Project Name	High-Level Scope	High-Level Estimate ($M)
Planning	TIE A	Upgrade approx. 0.04 miles of underground cable and conduit.	$0.5M
Planning	TIE B	Upgrade approx. 1.25 miles of overhead wire.	$8.6M

Q34. Did the Company consider energy storage as an alternative to the distribution infrastructure upgrades identified in the peaker-retirement evaluation?

A34. Yes. As discussed by Witness Pratt, the Company considered whether energy storage could mitigate distribution system impacts associated with peaker retirement. DO evaluated storage in relation to the localized support provided by the peaking units during abnormal operating conditions, planned outages, and contingency events.

The need for this localized support can extend beyond the duration typically provided by four-hour storage resources. In addition, land availability and other site-development constraints at the evaluated peaker sites can limit the amount of storage that could be installed and, therefore, the duration of support it could provide. Accordingly, while energy storage may provide benefits in certain applications, the four-hour storage resources evaluated would not, under the specific operating conditions studied, provide the same duration of localized support as the peaking units. The Company continues to evaluate longer-duration storage technologies as those technologies mature and become commercially available.

Q35. What are DO's next steps following the peaker analysis?

A35. DO will continue to coordinate with Energy Supply and other internal stakeholders as the IRP proceeding progresses. Following completion of the proceeding, and subject to the Commission's decision on the Company's proposed plan, DO would initiate the engineering and development of any mitigation projects associated with approved peaker-retirement scenarios through the Company's normal planning and project-development processes.

If mitigation projects are required to maintain system reliability following an approved peaker retirement, the Company would seek recovery of the associated costs through future rate proceedings or other applicable regulatory mechanisms. The Company would proceed with the projects and related retirements if the necessary regulatory approvals and cost recovery are obtained.

Q36. Does this complete your direct testimony?

A36. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JABLAN DJORDJEVIC

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JABLAN DJORDJEVIC

Line No.

Qualifications

Q1. What is your name, by whom are you employed, and what is your business address?

A1. My name is Jablan Djordjevic and I am employed by the DTE Electric Company (DTE Electric or Company) as an Expert Engineer in the Business Planning and Development (BP&D) organization. My business address is One Energy Plaza, Detroit, Michigan 48226.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I hold a Bachelor of Science degree in Electrical Engineering from Wayne State University, earned in 2007 (Detroit, Michigan, USA). Prior to that, my interest in electrical engineering started in high school and I hold a Power System Electro-Technician diploma from the Nikola Tesla High School (Belgrade, Serbia) focused on the alternating current and direct current electrical principles, three phase power systems applications, and rotating machine technology.

Q4. What work experience do you have, including current role and responsibilities?

A4. I have over 18 years of experience in electrical power system engineering, real-time system operations, transmission/distribution planning and interconnections, and long-term strategy with DTE Electric. My career includes extensive technical

analysis work, operational leadership, major technology integration projects, transmission/distribution reliability analysis and interconnections expertise.

I began my career as a Relay Performance and Supervisory Control and Data Acquisition (SCADA) Engineer, from 2007 to 2010, managing relay protection maintenance programs and field commissioning activities, performing fault and disturbance analysis, executing short-circuit studies, leading efforts for the first North American Electric Reliability Corporation (NERC) compliance audit for the PRC-005 standard, leading relay and SCADA upgrade projects, including development of electromechanical relay testing procedures and the automated relay test scripts for the microprocessor based relays.

From 2010 to 2014, I worked as a Central System Supervisor, administering switching and tagging operations, monitoring real-time bulk power conditions, mitigating contingencies, coordinating voltage control, supporting outage mitigation to improve reliability metrics such as Customer Average Interruption Duration Index (CAIDI), System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

From 2014 to 2015, I served as an Integrated Resource Plan (IRP) Principal Market Engineer. In this role, I supported development of various production and capacity expansion models, performed engineering and economic evaluation of new technologies, and contributed to prior IRP cycles supporting the Production Modeling analysis work.

Line No.

From 2015 to 2022, I served as a Senior System Supervisor, where I led major system operations technology upgrades, including the full transition from Asea Brown Boveri (ABB) Energy Management System (EMS) to Open Systems International (OSI) EMS in record time and the further integration of the Advanced Distribution Management System (ADMS) applications. I supervised the System Operations Center Control Room, ensured real-time operational safety, security and continuity of service for the DTE Electric system, and represented the Company at industry conferences such as DistribuTECH, Edison Electric Institute (EEI), and Electric Power Research Institute (EPRI).

In my current role as an Expert Engineer, from 2022–present, my responsibilities include performing generator interconnection studies, conducting system reliability and contingency analyses, leading technical evaluations related to storage, renewable as well as traditional non Inverter Based Resource (IBR) generating facility interconnections that includes request for proposals (RFP), leading and supporting Generator Interconnection Agreement (GIA) negotiations, supporting Midcontinent Independent System Operator (MISO) transmission planning such as MISO Transmission Expansion Planning (MTEP) and Long Range Transmission Planning (LRTP) with solutions validation and alternative analysis, and providing transmission-focused engineering support for DTE Electric's IRP.

Q5. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A5. No. I have not previously sponsored testimony before the MPSC.

Line No.

Purpose of the Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to explain and support the transmission system engineering grid studies performed for the Company's 2026 IRP that were developed in collaboration with the local Transmission Owner (TO), International Transmission Company (ITC). My testimony addresses how this application complies with the MPSC's IRP filing requirements for transmission analysis and related Certificate of Necessity (CON) components.

Specifically, I will:

a) Describe the scope of the Transmission Grid Studies and analysis, define the study approach, and outline DTE Electric's collaboration with ITC;

b) Describe the results of the initial studies in terms of the transmission system upgrades and cost required to mitigate system planning violations;

c) Discuss DTE Electric's Proposed Course of Action (PCA) supported by the Grid Study Analysis;

d) Provide updated Capacity Import Limits (CIL). Discuss Grid Enhancing Technologies (GETs), storage co-benefits and explain peaker sensitivities used in the study.

e) Address interconnection-related transmission study requirements for the Company's CON requests.

Q7. Are you sponsoring any exhibits with your direct testimony?

A7. Yes. I am sponsoring the following exhibits:

Line No.	Exhibit	Description
1	Exhibit	Description
2	A-14	ITC and DTE Grid Study Memo
3	A-14.1	ITC and DTE Grid Study Meeting Notes
4		

5 **Q8. Were these exhibits prepared by you or under your direction?**

6 A8. Exhibit A-14 was prepared by ITC, the local Transmission Owner, based on
7 transmission analyses performed in collaboration with DTE Electric to support the
8 Company's 2026 IRP. Throughout the study process, I worked closely with ITC's
9 technical team to direct the development of the study assumptions, analytical
10 criteria, performance metrics, scenario definitions, and interpretation of results that
11 form the basis of Exhibit A-14. Accordingly, while Exhibit A-14 was authored by
12 ITC, it was developed through a collaborative effort between DTE Electric and ITC
13 under my participation and direction on behalf of DTE Electric.
14
15 Exhibit A-14.1 contains the meeting notes, from the regularly scheduled meetings
16 organized by DTE Electric that document the collaborative study process, prepared
17 under my direction.
18
19 **Q9. How is your testimony organized?**

20 A9. My testimony is organized in the following five (5) parts:

21 **Part I: ITC and DTE Electric Engagement and Analysis Definitions**

22 **Part II: Discussion of Initial Grid Study Results**

23 **Part III: DTE Electric Final 2026 PCA Supported by the Grid Study Analysis**

24 **Part IV: Capacity Import Limit (CIL), Capacity Export Limit (CEL) and**

25 **Other Grid Study Components**

Part V: Transmission and Interconnection Considerations for CON

Part I: ITC and DTE Electric Engagement and Analysis Definitions

Q10. Did DTE Electric engage with the local transmission owner in the development of the IRP?

A10. Yes. DTE Electric engaged with the local Transmission Owner, ITC, a subsidiary of ITC Holdings Corp, a Fortis Company in the development of the IRP. In MISO's Balancing Authority, Local Resource Zone 7 (Michigan Lower Peninsula) is served by two distinct high-voltage transmission areas that transmit electricity from generating stations to local electricity distribution facilities. These two transmission system areas are operated by ITC and are known as the International Transmission Company Transmission (ITCT) and Michigan Electric Transmission Company (METC), where ITCT covers Southeastern Michigan and METC covers most of the Southwestern and Northern Michigan.

Q11. What was the purpose of the engagement between ITC and DTE Electric?

A11. The purpose of the engagement between ITC and DTE Electric was to ensure the evaluation of transmission system impacts and requirements were performed in accordance with the MPSC's IRP framework, as established in the Commission's Order in Case Nos. U-21867 and U-21570 (December 18, 2025), Exhibit B, Section XIII (Transmission Analysis), pp. 24-26. Consistent with these requirements, DTE Electric has conducted coordinated transmission studies with ITC utilizing steady-state power flow and dynamic stability analysis to assess system performance under both base case and contingency conditions. These analyses include evaluation of thermal loading, voltage performance, stability parameters and transfer capability

across relevant interfaces, as well as assessment of deliverability constraints within MISO Zone 7, summarized with applicable cost estimates to build the transmission grid. The results of these studies directly support the PCA resource selection and portfolio development, ensuring that the proposed plan meets reliability and operational performance requirements in a technically feasible and cost-effective manner.

Q12. Can you summarize the IRP related interactions with ITC?

A12. Yes. From December 2024 through September 2026, DTE Electric collaborated with ITC over multiple meetings; Table 1 below summarizes the meeting dates and topics, and Exhibit A-14.1 contains the meeting minutes. In addition, ITC and DTE Electric held ad-hoc technical meetings during this same period to ensure that the data inputs for the Grid Studies were complete and quality control checked. The ad-hoc technical meetings ranged from 15 minutes to 2 hours at a time and meeting minutes were not recorded for these sessions.

Table 1 DTE Electric and ITC Meeting Summary

Theme	Meeting Dates	Main Topics Discussed	Key Outputs / Decisions
Planning	12/06/2024, 02/13/2025, 02/28/2025, 03/14/2025, 04/04/2025, 04/25/2025	Initial coordination, IRP kickoff, study objectives, timeline, scenario feasibility, modeling assumptions, and MISO base case selection.	Defined study scope, sensitivities (Monroe retirement, storage, data centers), scenario matrix, and modeling assumptions; selected base models (2028–2045).
Preliminary Modeling	05/09/2025, 05/23/2025, 06/06/2025, 06/20/2025, 07/11/2025,	Resource modeling, topology adjustments, base case builds, data sharing, and early constraint identification with stability study initiation.	Confirmed resource assumptions, initiated model development, enabled data exchange, identified preliminary

Line No.

Theme	Meeting Dates	Main Topics Discussed	Key Outputs / Decisions
	07/21/2025, 08/08/2025		constraints, and launched dynamic stability analysis.
Study Draft Review	08/29/2025, 09/12/2025, 09/26/2025	Preliminary upgrade costs, cost methodologies, stability needs, and scenario updates	Established cost framework, identified voltage support needs, and refined scenarios with updated resource assumptions.
Study Draft Review	10/10/2025, 10/31/2025, 11/07/2025	Scenario reruns, CIL analysis initiation, near-final stability results, and emerging transmission cost trends.	Completed reruns, initiated CIL evaluation, reduced uncertainty in results, and mitigation impacts.
Study Draft Review	11/21/2025, 12/05/2025, 12/19/2025	Base case validation, cost corrections, data center integration, Monroe retirement analysis, and executive-level study review.	Validated results, corrected cost allocations, aligned scenarios with IRP needs, and defined targeted stability analysis requirements.
Finalization Planning	01/16/2026, 01/30/2026, 02/13/2026, 02/27/2026	Scenario scoping, study-year alignment, portfolio assumptions, and final model inputs and timelines.	Finalized scenario set, locked modeling inputs, defined study scope (N-1, N-1-1, CIL), and aligned schedule with PCA (May 2026).
Final Modeling & Compliance	03/13/2026, 03/27/2026	Final scenario refinement and incorporation of IRP compliance elements (GETs, out-of-state transmission), plus stakeholder planning.	Finalized study scope, incorporated compliance requirements, and confirmed stakeholder engagement strategy.
Execution & Results Delivery	04/10/2026, 04/24/2026, 05/08/2026, 05/22/2026, 06/05/2026, 06/19/2026, 07/02/2026, 07/17/2026, 07/31/2026, 08/17/2026, 08/21/2026, 08/28/2026, 09/11/2026	Model completion, study execution, GETs discussion, and coordination for IRP deliverables and testimony development.	Completed model builds, initiated all study runs, and began integrating results into transmission memo, testimony, and stakeholder presentations.

Q13. How was ITC's scope of work defined?

A13. DTE Electric engaged in a collaborative process with ITC to define and refine the scope of work for transmission studies needed to support the 2026 IRP filing. Early in the IRP planning phase, joint planning meetings were initiated to align both companies on objectives, regulatory filing requirements, and key assumptions. By collaboratively developing and refining the scope in this manner, DTE Electric and ITC ensured that the IRP's transmission studies fully satisfied all requirements. Stakeholder expectations and regulatory obligations (including MCL 460.6t(6)(iii) and related MPSC filing requirements for transmission analysis) were integrated into the scope from the outset. At the formal IRP kick-off meeting in early 2025, DTE Electric and ITC outlined a preliminary scope of the studies. The preliminary scope detailed the transmission analyses to be performed, including the specific years, scenarios, and sensitivities to examine (such as various timing options for the Monroe Power Plant retirement, high large load growth, and diverse resource replacement strategies). Throughout 2025 and 2026, DTE Electric and ITC met frequently (approximately bi-weekly) to review study progress and incorporate evolving elements into the scope of work. The scope was adjusted to reflect updated IRP scenarios, new load forecasts (emerging large customer load scenarios), and each adjustment to the scope was made transparently and documented in meeting minutes, ensuring both parties remained aligned.

The result was a comprehensive and compliance-driven set of transmission studies, jointly scoped and executed, ensuring that DTE Electric's IRP PCA has been thoroughly vetted for transmission cost estimation, feasibility and reliability.

Q14. What are the key elements of the analyses performed in the ITC's evaluation of DTE Electric's IRP scenarios?

A14. The ITC and DTE Electric Grid Study analysis was designed to determine the nature and extent of transmission planning and stability violations associated with changes in the generation resources, transmission topology and addition of the large loads (MISO Zone 7). In the analyses, DTE Electric provided the input data, and ITC modeled the snapshot of the transmission system representing summer peak load and summer shoulder load conditions for the most impactful years in terms of the system changes. The assumption factors evaluated within the transmission system impacts include generation retirement, generation interconnection, generation attributes, load forecasts, and planned transmission changes. The analysis was based on ITC's published planning practices and criteria in accordance with NERC Transmission Planning (TPL) Standards. ITC then estimated the costs to resolve such violations and to interconnect new Generating Facilities.

The study was designed to evaluate several key transmission planning questions associated with the Company's resource portfolio, including the transmission impacts of Monroe Power Plant retirement timing, the benefits and impacts of dispatchable replacement resources, the impacts of renewable replacement resources, the effects of significant large load growth, future Capacity Import Limit capability, and the benefits associated with major regional transmission investments such as the MISO Long Range Transmission Planning (LRTP) portfolios.

Q15. What are the main parts of the study performed by ITC?

A15. The main elements of the study performed by ITC included the following:

- Steady state contingency analysis – Thermal and voltage violations on the transmission system for the base case and N-1 contingency conditions.
- Stability analysis – Testing electrical system's ability to maintain generation and load balance (stay in synchronism) after major disturbances, N-1 and N-1-1, given the scenario impacts due to the retirement of major generating units.
- Transmission system upgrade cost estimation – Costs to mitigate violations to the transmission planning criteria associated with both retirement of existing generating units and addition of new resources.
- New generation interconnection facility direct attachment cost estimation.
- CIL analysis – Impacts from DTE Electric's initial scenarios and PCA to the capacity import capability of the Lower Peninsula of Michigan.

Q16. Can you briefly describe what a transmission steady state analysis is?

A16. A transmission steady state analysis consists of solving for the electrical system power flow after the transient effects of switching and/or disturbances have passed, and the system is operating in equilibrium for the forward-looking time. This is where resulting electrical system metrics such as thermal and voltage violations are monitored and compared between scenarios and cases. The base case and applied contingency analysis are evaluated at steady state.

Q17. Can you explain both thermal and voltage violations?

A17. Yes.

Thermal Violation**:** Every Transmission facility (i.e., transmission line, transformer, breaker, switch, etc.) has a certain loading capacity (i.e., current carrying capacity), which is also termed as thermal rating (MVA) of the facility. To avoid equipment damage and ensure safety, the transmission facility loading projected in the system models should be maintained below the normal and/or emergency thermal limits as defined by the transmission planning criteria set by the TO. If the current flowing through any transmission facility is above the thermal rating of the facility, the incident is defined as a thermal violation.

Voltage Violation: To avoid equipment damage and ensure reliability, transmission bus voltages projected in system models should be maintained within the limits as defined by the transmission planning criteria set by the TO. If the voltage of a certain transmission bus is found to be out of the limit defined in the transmission planning criteria, the incident is defined as a voltage violation.

Q18. What are N-1 and N-1-1 contingencies and what is the difference?

A18. An N-1 contingency is defined as a single event that causes a loss of a power system element (example: transmission line or a generator). An N-1-1 contingency is a more severe condition in which a second event occurs after the initial contingency, where in between these two contingencies, automatic equipment response and operators have had an opportunity to take corrective actions. The goal of the contingency analysis is to identify violations on the transmission system under a range of equipment outage conditions.

Q19. Can you briefly describe what a transmission stability analysis is?

Line No.

A19. The transmission stability analysis measures and records the ability of the power system to stay in synchronism and return to an adequate stable operating condition after a fault/disturbance event is applied to the power system. System parameters are typically observed over 20 second time period, to ensure system response is dampened and stable.

Q20. What scenarios were provided by DTE Electric to ITC for the steady state transmission analyses?

A20. DTE Electric provided 20 initial steady state scenarios for ITC to evaluate as set forth in the table below. The scenarios were developed by DTE Electric. They contain the 2022 IRP PCA largely as the initial input, with the incremental adjustments for unit retirements, replacement generation and topology changes.

Table 2 Initial Study Scenario Lineup

Scenario	Target Year	Study Case Descriptor	Major Incremental Model Adjustments
A_2028_BASE	2028	A1_3Y_2028_SPK_BASE	Add topology and build plan for the y2028. Add DC1 and DC2 (~2400 MW).
A_2028_SC1	2028	A2_3Y_2028_SPK_CHG1	Retire MONPP U3/U4.
A_2028_BASE	2028	A3_3Y_2028_SH_BASE	Add topology and build plan for the y2028. Add DC1 and DC2 (~2400 MW).
A_2028_SC1	2028	A4_3Y_2028_SH_CHG1	Retire MONPP U3/U4.
A_2030_BASE	2030	A5_5Y_2030_SPK_BASE	Start with A2. Add topology and build plan for the y2030.
A_2030_SC1	2030	A6_5Y_2030_SPK_CHG1	Retire MONPP U1/U2.
A_2030_BASE	2030	A7_5Y_2030_SH_BASE	Start with A4. Add topology and build plan for the y2030.
A_2030_SC1	2030	A8_5Y_2030_SH_CHG1	Retire MONPP U1/U2.
B_2032_BASE	2032	B1_7Y_2032_SPK_BASE	Start with A6. Add topology and build plan for the y2032. Retire Tier 2 Peakers.
B_2032_SC1	2032	B2_7Y_2032_SPK_CHG1	Add CCGT 1.

Line No.

Scenario	Target Year	Study Case Descriptor	Major Incremental Model Adjustments
B_2032_SC2	2032	B3_7Y_2032_SPK_CHG2	Add large load growth (~1100 MW).
B_2032_SC3	2032	B4_7Y_2032_SPK_CHG3	Add CCGT 2.
B_2032_SC4	2032	B5_7Y_2032_SPK_CHG4	Replace CCGT proxy units with Renewables Solar (3000 MW ICAP).
B_2032_BASE	2032	B6_7Y_2032_SH_BASE	Start with A8. Add topology and build plan for the y2032. Retire Tier 2 Peakers.
B_2032_SC1	2032	B7_7Y_2032_SH_CHG1	Add CCGT 1.
B_2032_SC2	2032	B8_7Y_2032_SH_CHG2	Add large load growth (~1100 MW).
B_2032_SC3	2032	B9_7Y_2032_SH_CHG3	Add CCGT 2.
B_2032_SC4	2032	B10_7Y_2032_SH_CHG4	Replace CCGT proxy units with Renewables Solar (3000 MW ICAP).
C_2045_BASE	2045	C1_20Y_2045_SPK_BASE	Start with B4. Add topology and build plan for the y2045. Place offline Nat. Gas Units + Tier 1 Peakers to enable Renewable Generation.
C_2045_BASE	2045	C2_20Y_2045_SH_BASE	Start with B9. Add topology and build plan for the y2045. Place offline Nat. Gas Units + Tier 1 Peakers to enable Renewable Generation.

Q21. Can you describe Scenario Groups A, B, and C?

A21. Yes. Group A Scenarios (A1-A8): Designed to test the system in the near term (3-5 year) period and to evaluate the transmission impacts associated with the planned retirement of Monroe Power Plant Units 3 and 4 in 2028 and early retirement of Monroe Power Plant Units 1 and 2 in 2030 under anticipated transmission topology, generation additions, and approximately 2,400 MW of large load growth associated with DC1 Oracle America Cloud Services (OACS) and DC2 Google LLC, approved via the MISO Expedited Project Review (EPR), during the MISO MTEP 26 cycle process.

Line No.

Group B Scenarios (B1-B10): Designed to test the system in the mid term (7 year) period and to evaluate alternative replacement resource strategies following Monroe Power Plant retirement, including dispatchable CCGT additions, renewable replacement resources, additional prospective large load growth and by placing Tier 2 peaking resources offline. These scenarios build on the near-term scenarios (Group A) and include incremental adjustments to the Generating Facilities and Transmission Projects. Furthermore, Monroe Power Plant Unit 1, 2, 3 and 4 remain retired and additional 393 MW of Tier 2 Peakers are placed offline and assumed unavailable for dispatch. Four change cases test the system by adding dispatchable generation in the form of combined cycle gas turbine (CCGT) with carbon capture and storage (CCS) technology and by inserting additional large load of close to 1100 MW for a total of 3500 MW large loads. Dispatchable Generating Facilities have 1500 MW capacity each, for a total of 3000 MW, sited at the NW and SW edges of the DTE Electric Service Territory and ITCT Transmission Area. One scenario includes Renewable Generation instead of dispatchable generation at the Installed Capacity (ICAP) value of 3000 MW.

Group C Scenarios (C1-C2): Designed to test the system in the long term (20 year) period. These scenarios build on the mid-term scenario (Group B) and include incremental adjustments to the Generating Facilities and Transmission Projects. Furthermore, all un-mitigated carbon producing large generators and peakers are placed offline to enable Renewable Generation dispatch, with minimal transmission topology change and no additional large loads. Remaining Generating Facilities are added per the 2022 IRP PCA and including the CCGT 1 and 2 proxy generation.

Q22. Can you summarize the resource, load and transmission assumptions in the overall initial scenario analysis?

A22. Yes. The initial inputs into the 20 year study scenario are driven by the previously approved 2022 IRP portfolio and include the following:

- Conventional generating units assumed unavailable for dispatch under the evaluated scenarios, representing approximately 5102 MW installed capacity.
- Conventional Peaker units assumed unavailable for dispatch under the evaluated scenarios, representing approximately 1494 MW installed capacity.
- Wind additions of 8900 MW installed capacity, dispatched at 20% in the summer peak and 27% in the summer shoulder scenarios.[1]
- Solar additions of 8153 MW installed capacity, dispatched at 30% in both summer peak and summer shoulder scenarios.[2]
- Storage additions of 3467 MW installed capacity, dispatched at 100% discharging or stand by in summer peak and 100% charging in summer shoulder scenarios.
- Dispatchable resources of 3000 MW installed capacity, dispatched up to 100% in both summer peak and summer shoulder scenarios.
- Large Load additions of 3500 MW.
- MISO MTEP and LRTP Tranche 1 and Tranche 2.1 approved projects.

[1] MISO25 Series Model Development Update: https://cdn.misoenergy.org/20250602%20CSPM%20Item%2003%20MISO25%20Series%20Model%20Development%20Update699309.pdf, accessed August 2026.

[2] MISO has a variety of solar dispatch percentages for the larger number of scenarios and sensitivities, ranging from 0% to ~50% for the MTEP25 series of models. Solar dispatch of 30% was chosen to represent less than ideal summer peak or summer shoulder day for a more conservative analysis in our study.

Grid Study results are presented in Part II: Discussion of Initial Grid Study Results. See Exhibit A-14 for additional detail on the scenarios.

Q23. Can you describe the transmission system planning models used for the study?

A23. Yes. MISO annually develops a series of transmission system models with different planning (time) horizons in each MISO MTEP cycle. The MISO transmission models used by ITC in the Company's IRP studies (both steady state and stability) were developed based on the MTEP25 series of models.[3] The available transmission models in the MTEP25 series of models were the 1-year (2026), 2-year (2027), 5-year (2030) and 10-year (2035) models. ITC used the 2-year model to develop scenarios for the year 2028, 5-year model for the year 2030/2032 scenarios, and 10-year model to develop the year 2045 scenarios for the IRP study. IRP scenarios described above were evaluated across four different years (3, 5, 7 and 20 year) and two snapshots for each year (summer peak and summer shoulder conditions). ITC adjusted the dispatch of the generators in the transmission models for both DTE Electric and the rest of MISO Zone 7.

Q24. How were the generation replacement resources sited in the model?

A24. DTE Electric provided ITC with siting assumptions for the replacement generation to include in the modeling over the 20-year study period and which represented DTE Electric's share of resources. Siting was determined by using the existing MISO queue positions, prior injection studies, and information from the more recent injection studies:

[3] MISO25 Series Model Development Update: https://cdn.misoenergy.org/20250602%20CSPM%20Item%2003%20MISO25%20Series%20Model%20Development%20Update699309.pdf, accessed August 2026.

Line No.

1. Projects included in MISO's interconnection queue through 2023 cycle
2. ITC Hosting Capacity Study[4] based on the MTEP20 models
3. Company selected sites from the refreshed DTE Electric Bus Injection Study, using the MTEP24 models

DTE Electric siting assumptions utilized in the study were intended to place new resources at locations expected to provide favorable transmission characteristics and minimize incremental transmission investment requirements based on available planning information. The specific siting assumptions for the rest of the MISO Zone 7 were determined by ITC based on the base case inputs from other Generation Owners.

Q25. Did the Company request an additional scenario to be studied by ITC?

A25. Yes. The Company requested a final 2026 PCA check in August 2026 to analyze the steady state impacts of the final portfolio of resources and to verify that the new 2026 PCA is on target to comply with the transmission planning criteria. Please refer to the Testimony of Witness Manning for the additional details on the final 2026 IRP PCA portfolio development.

Final 2026 IRP PCA Grid Study results are presented in Part III: DTE Electric Final 2026 PCA supported by the Grid Study Analysis.

[4] ITC Michigan Hosting Capacity Study: https://www.oasis.oati.com/woa/docs/ITC/ITCdocs/MI_Hosting_Capacity_-_Final.pdf, accessed January 2025.

Part II: Discussion of Initial Grid Study Results

Q26. Did ITC provide a copy of its study results?

A26. Yes. ITC provided DTE Electric with a copy of its study results summarized and interpreted in the form of a memorandum, included as Exhibit A-14. The memorandum summarizes the study assumptions, transmission planning analyses, stability analyses, Capacity Import Limit evaluations, identified transmission reinforcements, and associated cost estimates that form the basis for the findings and conclusions discussed below.

Q27. Can you please summarize the key findings of the steady-state transmission analysis performed by ITC for Group A, Group B, and Group C Scenarios?

A27. Yes. ITC performed the steady state thermal and voltage analysis on the three initial groups of scenarios to identify the thermal and voltage violations across the ITCT and METC footprints and determined Corrective Action Plans (CAPs) for mitigating the violations. The cost estimates corresponding to the transmission CAPs required for the mitigation of the thermal and voltage violations are included in the cumulative cost summary table in Table 4 of Exhibit A-14. The key findings of the steady-state transmission analysis combining initial study scenarios are summarized in the table below.

Table 3 Key Findings from the Group A, B and C Scenario Studies

Observation	Finding
Monroe Power Plant Retirements	Retirement of Monroe Power Plant Units 3 and 4 in 2028 resulted in materially higher transmission reinforcement requirements. Additional retirement of Monroe Power Plant Units 1 and 2 in 2030 further increased transmission system costs, demonstrating the transmission planning value currently provided by the Monroe Power Plant facility.

Line No.

Observation	Finding
LRTP Benefits	MISO LRTP Tranche 1 projects reduced transmission upgrade requirements and improved transfer capability in the 2030 and 2032 study horizons. Additional benefits associated with LRTP Tranche 2.1 were observed in the 2045 scenarios where the Tranche 2.1 facilities were incorporated into the transmission topology.
Dispatchable Resources	A strategically located CCGT 1 proxy of 1,500 MW dispatchable resource reduced overall transmission-related costs by approximately $265 million relative to the Base Case and produced the lowest grid-study cost among the 2032 transmission scenarios evaluated in the study. The results demonstrate that properly sited dispatchable generation can reduce transmission constraints, support local reliability, and defer transmission reinforcement requirements. Incremental dispatchable generation above 1,500 MW must be strategically located and sized to avoid creating new transmission constraints.
Large Load Growth	Additional large load growth increased transmission investment requirements and partially offset the transmission benefits associated with dispatchable resource additions. The addition of approximately 1,100 MW of large load increased transmission-related costs by approximately $198 million relative to the comparable dispatchable generation case.
Renewable Replacement Resources	Renewable replacement resources performed favorably relative to the Base Case and were able to be integrated with transmission-related costs comparable to or lower than the Base Case. While renewable portfolios generally required higher interconnection investments, they did not materially increase transmission reinforcement requirements relative to the Base Case.
System Strength and Reactive Support	The stability analyses did not identify widespread transmission stability concerns; however, the 2045 study identified a localized low short-circuit-strength condition that was mitigated through a potential synchronous condenser solution. These results indicate that system strength and reactive power support become increasingly important as synchronous generation retires and inverter-based resource penetration increases.
Long-Term Outlook	Transmission cost intensity declined from approximately **$301/kW in 2028** to approximately **$86/kW in 2045**, reflecting the cumulative benefits of regional transmission expansion, LRTP investments, and a more mature resource portfolio.

Q28. What are the Generator Interconnection Facility costs?

A28. New Generating Facilities require a connection to the transmission system at their Point of Interconnection (POI) in order to inject or withdraw power from the electric system. Depending on the location and characteristics of the project, the facilities required to establish this connection may include new substations, transmission line connections, breaker configurations, switchgear, protection and control systems, and other interconnection-related equipment. The costs associated with constructing these facilities are generally referred to as **Generator Interconnection Facility costs** or **Direct Attachment Facility costs**. These costs are distinct from broader transmission network upgrades that may be required to maintain compliance with transmission planning criteria and reliably accommodate the new generation resource. Throughout the transmission analyses discussed in this testimony, generator interconnection costs are reported separately from transmission reinforcement costs to distinguish the direct costs of connecting new resources from the costs associated with mitigating broader transmission system impacts, recorded in Table 3 of Exhibit A-14.

Q29. Can you define Corrective Action Plan (CAP)?

A29. Yes. If the transmission planning analysis identifies thermal and/or voltage violations, transmission upgrades and/or other actions will be proposed to mitigate any projected violations of the transmission planning criteria as defined by the TO. The mitigation project/action is termed as a CAP.

Q30. What transmission network upgrades were identified as CAPs to mitigate the thermal violations identified in the steady state analysis?

A30. The required transmission enhancements identified as CAPs involved transmission facilities above 100 kV across the ITCT and METC footprints. The thermal CAPs included the following upgrades:

- Station Upgrades: To mitigate overloads on substation terminal equipment.
- Line Upgrades: To mitigate overloads on underground cable systems, sag limited overhead lines, and conductor limited overhead and underground lines.
- Transmission facility rebuilding and reconductoring projects where required to increase thermal capability.

Refer to Table 1 and Table 2 of Exhibit A-14 for details on the cumulative thermal corrective project types and corrective project line miles identified in the steady state analysis for each ITC scenario.

Q31. What is the cost share ratio of the thermal, voltage, and stability upgrade costs attributed to DTE Electric's resource portfolio in the study results?

A31. The transmission planning and stability analyses evaluated generation additions from multiple Generation Owners located within the Michigan Lower Peninsula. As a result, not all identified transmission reinforcement requirements were attributable solely to DTE Electric's future resource additions. To allocate transmission upgrade costs for purposes of comparing resource portfolios, ITC applied a cost responsibility factor based on the relative share of generation additions represented by the DTE Electric portfolio in the long-term study horizon. Specifically, the 2045 Group C Base Case included approximately **23,520 MW** of new generation additions for DTE Electric, which represents approximately **64.8%** of the total generation additions modeled in the study. Consequently, thermal,

voltage, and stability-related upgrade costs identified through the analyses were allocated to DTE Electric using the 64.8% ratio, while generator interconnection facility costs were assigned directly to the specific resources being evaluated. The use of this allocation methodology provides a reasonable planning-level estimate of the transmission reinforcement costs attributable to DTE Electric's resource portfolio and allows for consistent comparison of the transmission impacts associated with the alternative scenarios evaluated in this testimony. This cost share ratio remained constant and unchanged for all steady state and stability analyses.

Group A Scenario Results (A1-A4, 3-year period, y2028)

Q32. What assumptions were included in the 2028 Group A transmission analysis?

A32. The 2028 Group A analysis was performed using a Base Case and an associated Change Case. The Base Case incorporated the anticipated 2028 transmission topology and approved transmission build plan, along with the addition of the OACS (DC1) and Google LLC (DC2) contracted resources, totaling approximately 2,400 MW of new large load. The Change Case was developed from the Base Case by retiring Monroe Power Plant Units 3 and 4. The purpose of the analysis was to identify any incremental transmission system impacts and associated transmission reinforcements required as a result of those retirements.

Q33. What were the results of the 2028 Group A transmission analysis?

A33. The analysis identified **$1.41 billion** of thermal transmission upgrades and **$238 million** of generation interconnection facilities, for a total of **$1.65 billion** of transmission-related costs, required in the Base Case to support the 2028 transmission system and resource portfolio. The Base Case incorporated the

planned 2028 transmission topology, approved transmission build plan, and approximately **2,400 MW** of large load additions associated with the DC1 and DC2 projects.

When Monroe Power Plant Units 3 and 4 were retired in the Change Case, the study identified **$910 million** of additional thermal transmission upgrades, resulting in a total transmission-related cost of **$2.56 billion**. These results indicate that retirement of Monroe Power Plant Units 3 and 4 materially increases transmission reinforcement requirements under the 2028 study assumptions.

The transmission impacts associated with the Monroe Power Plant Units 3 and 4 retirement are also reflected in the physical transmission reinforcements identified by the study. The retirement sensitivity increased the number of Corrective Action Plans from 80 to 91 and increased the required transmission line reinforcements from approximately 442 to 611 line miles. These results demonstrate that the Monroe Power Plant retirements materially increase transmission system reinforcement requirements beyond the transmission costs alone.

Q34. What does the incremental transmission cost represent?

A34. The incremental transmission cost represents the additional transmission reinforcements required beyond those already identified in the Base Case. Because the Base Case already included the planned 2028 transmission system, approved transmission upgrades, and the addition of approximately **2,400 MW** of new large load associated with the DC1 and DC2 projects, the additional **$910 million** reflects thermal transmission upgrades specifically attributable to the

retirement of Monroe Power Plant Units 3 and 4. These upgrades are intended to maintain compliance with applicable transmission planning criteria and ensure reliable system operation following the retirements and in the absence of the future planned LRTP Tranche 1 projects.

Q35. How much generation was evaluated and what was the resulting additional transmission cost?

A35. The 2028 Group A analysis evaluated approximately **5,470 MW** of generation additions. The Base Case transmission investment equated to approximately **$301/kW** of generation added. After accounting for the incremental transmission upgrades associated with the retirement of Monroe Power Plant Units 3 and 4 in 2028, the transmission cost increased to approximately **$467/kW**. These results demonstrate that retirement of Monroe Power Plant Units 3 and 4 materially increases the transmission investment required to support the 2028 resource portfolio.

Group A Scenario Results (A5-A8, 5-year period, y2030)

Q36. What assumptions were included in the 2030 Group A transmission analysis?

A36. The 2030 Group A analysis was performed using a Base Case and an associated Change Case. The Base Case incorporated the anticipated 2030 transmission topology and approved transmission build plan and assumed that Monroe Power Plant Units 3 and 4 had already been retired. The Change Case was developed from the Base Case by additional retirement of Monroe Power Plant Units 1 and 2 in 2030, representing the accelerated Monroe Power Plant retirement scenario. The purpose of the analysis was to identify any incremental transmission system

impacts and associated transmission reinforcements required as a result of those additional retirements.

Q37. What were the results of the 2030 Group A transmission analysis?

A37. The analysis identified **$1.61 billion** of thermal transmission upgrades and **$350 million** of generation interconnection facilities, for a total of **$1.96 billion** of transmission-related investment that is required in the Base Case to support the 2030 transmission system and resource portfolio. When Monroe Power Plant Units 1 and 2 were retired in the Change Case, the study identified **$762 million** of additional thermal transmission upgrades needed to mitigate the incremental transmission system impacts associated with those retirements.

The retirement sensitivity of Monroe Power Plant Units 1 and 2 increased the number of Corrective Action Plans from 80 to 89 and increased the required transmission line reinforcement from approximately 502 to 664 line miles. These additional transmission reinforcements contributed to the increase in transmission investment requirements identified in the retirement sensitivity.

Q38. What does the incremental transmission cost represent?

A38. The incremental transmission cost represents the additional transmission reinforcements required beyond those already identified in the Base Case. Because the Base Case already included the planned 2030 transmission system, approved transmission upgrades, and the assumption that Monroe Power Plant Units 3 and 4 had been retired, the additional **$762 million** reflects thermal transmission upgrades specifically attributable to the retirement of Monroe Power Plant Units 1

and 2. These upgrades are intended to maintain compliance with applicable transmission planning criteria and ensure reliable system operation following the retirements.

Q39. How much generation was evaluated and what was the resulting additional transmission cost?

A39. The 2030 Group A analysis evaluated approximately **8,750 MW** of generation additions. The Base Case transmission investment equated to approximately **$224/kW** of generation added. After accounting for the incremental transmission upgrades associated with the retirement of Monroe Power Plant Units 1 and 2, the transmission cost increased to approximately **$311/kW**. These results demonstrate that retirement of Monroe Power Plant Units 1 and 2 materially increases the transmission investment required to support the 2030 resource portfolio.

Q40. Why are the transmission costs identified in the 2030 analysis lower than those identified in the 2028 analysis?

A40. The primary driver of the reduction in transmission costs between the 2028 and 2030 analyses is the inclusion of the MISO LRTP Tranche 1 projects in the 2030 transmission topology and build plan. The LRTP Tranche 1 projects provide substantial transmission system reinforcements across the region, increasing transfer capability and strengthening the underlying transmission network. As a result, many of the transmission constraints that required mitigation in the 2028 analysis were already addressed by the planned LRTP facilities included in the 2030 models.

Although retirement of Monroe Power Plant Units 1 and 2 in 2030 continued to require significant transmission reinforcements, the transmission cost intensity of the 2030 Base Case was lower than the 2028 Base Case due to the inclusion of the LRTP Tranche 1 facilities. The Base Case transmission investment decreased from approximately **$301/kW** in 2028 to approximately **$224/kW** in 2030, demonstrating the transmission planning benefits provided by the LRTP portfolio. These results indicate that major regional transmission investments can reduce future transmission reinforcement requirements and improve the ability of the system to accommodate resource portfolio changes.

Q41. What transmission planning observations can be made regarding retirement of the Monroe Power Plant Units 1, 2, 3 and 4 in 2030?

A41. The transmission analyses indicate that full retirement of the Monroe Power Plant units in 2030 increases transmission system needs and can require additional transmission reinforcements to maintain compliance with planning criteria. The Monroe Power Plant currently provides a large source of generation and reactive power support within Southeast Michigan. Consequently, replacing them with a similarly sized dispatchable resource capable of providing comparable real and reactive power support could reduce transmission system impacts, improve voltage performance, and lessen the need for certain transmission upgrades.

These results should not be interpreted as a conclusion that the Monroe Power Plant cannot be retired. Rather, the analyses indicate that retirement of the Monroe Power Plant units may require additional transmission reinforcements, replacement resources, and implementation of planned transmission expansion projects to

maintain compliance with applicable planning criteria and support reliable operation of the transmission system under the assumptions evaluated.

Q42. Are there any considerations regarding the timing of the transmission upgrades assumed in the 2030 analysis?

A42. Yes. The 2030 analysis assumes that the transmission facilities included in the approved transmission build plan, including the MISO LRTP Tranche 1 projects[5], are in service and fully available to support the transmission system. As discussed previously, the inclusion of these projects is a primary reason why the transmission costs identified in the 2030 analysis are lower than those identified in the 2028 analysis. Consequently, the ability to retire the Monroe Power Plant Units 1 and 2 as modeled is heavily dependent upon the successful implementation and timely completion of the planned transmission reinforcements. Delays in the development or in-service dates of major transmission projects could affect the availability of the transmission capability assumed in the study and may require additional analysis to determine whether alternative mitigation measures, replacement resources, or continued operation of existing generation would be needed to maintain system reliability.

The study results also demonstrate the importance of transmission expansion timing. While the 2030 analysis benefits from the inclusion of LRTP Tranche 1 facilities, the major LRTP Tranche 2.1 projects[6] and associated 765 kV

[5] MISO LRTP Tranche 1 Portfolio Dashboard: https://cdn.misoenergy.org/Tranche%201%20Dashboard732077.pdf?v=20251215143928
[6] MISO LRTP Tranche 2.1 Portfolio Dashboard: https://cdn.misoenergy.org/Tranche%202.1%20Dashboard732078.pdf?v=20251215144025

transmission backbone are not yet assumed to be in service, expected between 2032 and 2034. As a result, accelerating major generation retirements ahead of the broader LRTP Tranche 2.1 buildout could require a significantly more aggressive transmission reinforcement program to maintain reliability and accommodate replacement resources. The analyses indicate that coordination between generation retirement timing and major transmission project implementation is an important consideration in achieving a reliable and cost-effective transition of the generation fleet.

Moreover, these scenarios do not assume the addition of any other future incremental large load developments that may emerge over time. As a result, future transmission needs will remain dependent on both generation fleet changes and evolving load growth assumptions.

Q43. Are these transmission system analysis results a proxy for MISO's Attachment Y retirement analysis?

A43. No. The transmission analyses performed for the IRP are intended to inform long-term planning and do not replace the formal MISO Attachment Y generator retirement review process. The retirement of the Monroe Power Plant Units 1 through 4 would require additional reliability assessments addressing thermal, voltage, stability, and transmission import capability impacts. While the IRP analyses provide valuable insight into the potential transmission consequences of generation retirements and replacement resource strategies, the formal Attachment Y process evaluates the specific reliability impacts associated with a proposed retirement using the system conditions, assumptions, and reliability criteria

applicable at the time of the retirement request. Consequently, the results presented in this testimony should be viewed as planning-level analyses and not as a determination of whether a generating unit can be retired through the MISO Attachment Y process.

Group B Scenario Results (B1-B10, 7-year period, y2032)

Q44. What assumptions were included in the 2032 Group B transmission analysis?

A44. The 2032 Group B analysis was performed using a Base Case and four associated Change Cases. The Base Case incorporated the anticipated 2032 transmission topology and approved transmission build plan and assumed the full retirement of Monroe Power Plant Units 1 through 4. The Base Case also included approximately **10,570 MW** of generation resources and approximately **2,400 MW** of new large load.

Change Case 1 was developed from the Base Case by adding a dispatchable generation resource represented by CCGT Proxy 1 (1,500 MW). Change Case 2 incorporated the assumptions from Change Case 1 and added approximately **1,100 MW** of additional large load. Change Case 3 incorporated the assumptions from Change Case 2 and added a second dispatchable generation resource represented by CCGT Proxy 2 (1,500 MW). Finally, Change Case 4 replaced the dispatchable generation resources included in Change Case 3 with an equivalent Installed Capacity (ICAP) of solar renewable generation. The purpose of the analysis was to evaluate the transmission impacts associated with alternative resource strategies following the retirement of the Monroe Power Plant units.

The CCGT Proxy 1 and CCGT Proxy 2 resources evaluated in the sensitivity analyses were generic planning proxies and do not represent the final design, size and operating characteristics of the Livingston County or Monroe County Projects. Point of Interconnection is selected for each proxy unit so that they are interconnected approximately at the same electrical point in the model as per the Livingston County and Monroe County Projects queued positions. The proxies were used to evaluate the transmission impacts of strategically located dispatchable resources under planning-level assumptions. Livingston County Project and Monroe County Project MISO Interconnection Processes are described in detail in Part V of my testimony.

Q45. What were the results of the 2032 Group B transmission analysis?

A45. The analysis identified **$1.26 billion** of thermal transmission upgrades and **$420 million** of generation interconnection facilities, for a total of **$1.68 billion** of transmission-related costs, required in the Base Case to support the 2032 transmission system and resource portfolio. The Base Case included the retirement of Monroe Power Plant Units 1 through 4, Tier 2 peaking resources placed offline, approximately **10,570 MW** of generation additions, and approximately **2,400 MW** of large load additions.

Relative to the Base Case, Change Case 1 reduced transmission-related costs by approximately **$265 million**, indicating the lowest cost scenario. Change Case 2 reduced costs by approximately **$67 million**. Change Case 3 increased costs by approximately **$910 million**. Change Case 4 reduced costs by approximately **$23 million**. The analysis also identified varying levels of generator interconnection

costs associated with each sensitivity. These results demonstrate that transmission impacts are highly dependent on resource type, location, operating characteristics, and load growth assumptions.

Q46. What does Change Case 1 indicate regarding the addition of dispatchable generation?

A46. Change Case 1 evaluated the addition of a 1,500 MW dispatchable generation resource represented by CCGT 1. While the addition of the resource required approximately **$7 million** of incremental generator interconnection facilities, the study identified an overall reduction of approximately **$265 million** in total transmission-related costs relative to the Base Case. As a result, Change Case 1 produced the lowest overall transmission cost outcome among the 2032 sensitivity cases evaluated. The transmission planning benefits associated with Change Case 1 are also reflected in the CAP metrics. The study reduced the number of corrective actions from 72 to 66 and reduced required transmission line reinforcement from approximately 366 to 317 line miles, indicating that the dispatchable resource improved overall transmission system performance while reducing transmission investment requirements.

These results indicate that a strategically located dispatchable resource can provide substantial transmission system benefits by reducing power transfer requirements, improving power flow distribution, supporting local voltage performance, and alleviating transmission constraints that would otherwise require reinforcement. The study indicates that transmission planning outcomes are influenced not only by

the quantity of generation added, but also by the electrical characteristics, operating flexibility, and location of replacement resources.

The results further suggest that appropriately sited dispatchable generation may provide transmission value beyond its energy and capacity contributions by reducing future transmission investment requirements while supporting reliable operation of the transmission system. Consequently, Change Case 1 represents an example of how replacement resources can simultaneously support reliability objectives and reduce transmission-related costs when compared to a portfolio without a comparable dispatchable resource addition.

Q47. What impact did the additional large load have in Change Case 2?

A47. Change Case 2 evaluated the addition of approximately **1,100 MW** of additional large load beyond the assumptions included in Change Case 1. These assumptions are generally consistent with MISO's recently released Futures Series 2 scenarios[7], which project significantly higher long-term load growth across the footprint driven by data centers, electrification, manufacturing expansion, and other large load additions. Although the overall transmission-related costs remained below the Base Case, the additional large load increased costs by approximately **$198 million** relative to Change Case 1. These results indicate that significant large load growth can increase transmission investment requirements and partially offset the transmission benefits associated with additional generation resources. Assumed large loads are approved via MISO EPR process, part of MTEP cycle, with

[7] MISO Futures Report Series 2, relevant report pages 6, 7 and 27: https://cdn.misoenergy.org/MISO%20Futures%20Report%20Series%202766529.pdf, accessed September 2026.

associated Network Upgrades and costs assigned per their specific negotiated contracts.

Q48. What impact did the second dispatchable resource have in Change Case 3?

A48. Change Case 3 evaluated the addition of a second 1,500 MW dispatchable generation resource represented by CCGT 2 proxy. The analysis increased total transmission-related costs by approximately **$910 million** relative to the Base Case. While the total number of CAPs remained relatively similar to the Base Case (72 vs 73), the cost of the required upgrades increased significantly, demonstrating that transmission outcomes are influenced not only by the number of violations identified, but also by the location and severity of those violations and the transmission facilities affected.

These results demonstrate that transmission impacts depend not only on the quantity of generation added, but also on the location and interaction of those resources with transmission system power flows. The results indicate that the relationship between dispatchable resource additions and transmission costs is not linear and that the transmission performance is sensitive to both the size and location of dispatchable replacement resources, where additional study would be required to identify alternative configurations that may optimize transmission outcomes.

Q49. What did the analysis indicate regarding replacement of dispatchable generation with renewable generation in Change Case 4?

A49. Change Case 4 replaced the dispatchable generation resources modeled in Change Case 3 with approximately **3,000 MW of renewable solar generation**. The analysis reduced overall transmission-related costs relative to both the Base Case and Change Case 3, while requiring approximately **$56 million** of additional generator interconnection facilities. Total study costs decreased from approximately **$2.59 billion** in Change Case 3 to approximately **$1.65 billion** in Change Case 4, representing a reduction of approximately **$933 million**. The renewable replacement sensitivity required approximately 382 line miles of transmission reinforcement compared to approximately 321 line miles in Change Case 3. These results demonstrate that while additional renewable resources can be successfully integrated from a transmission planning perspective, transmission outcomes remain dependent on resource location, transmission configuration, and generation dispatch characteristics and they will require additional generator interconnection facilities due to numerous resource locations and points of interconnection.

Q50. How much generation was evaluated and what was the resulting transmission cost?

A50. The 2032 Group B analysis evaluated approximately **10,570 MW** of generation additions in the Base Case. The Base Case transmission investment equated to approximately **$159/kW** of generation added.

Change Case 1 resulted in the lowest transmission cost of approximately **$117/kW**. Change Case 2 resulted in approximately **$133/kW**, while Change Case 3 resulted in approximately **$191/kW**. Change Case 4 resulted in approximately **$122/kW**.

These results illustrate how different resource portfolios, including dispatchable generation, renewable generation, and additional large loads, can influence transmission reinforcement requirements and associated transmission costs.

Q51. What transmission planning observation can be made from the negative incremental transmission cost identified in Change Case 1?

A51. The negative incremental transmission cost identified in Change Case 1 indicates that the addition of a dispatchable generation resource can provide transmission system benefits that offset previously identified transmission upgrade needs. By adding a dispatchable generation resource represented by CCGT Proxy 1, which reflects electrical characteristics and siting generally consistent with the Livingston County Project, the study estimated a reduction of approximately **$265 million** in transmission investment requirements relative to the Base Case. These results indicate that strategically located dispatchable resources can improve transmission system performance, reduce reliance on long-distance power transfers, support local reliability needs, and potentially defer or eliminate certain transmission reinforcements.

In addition, steady-state transmission analysis does not fully capture the operational flexibility provided by dispatchable generation resources. The ability of dispatchable generation to increase or decrease output in response to changing system conditions may provide additional reliability and operational benefits beyond those reflected in the transmission cost estimates. Consequently, the study highlights the value of considering dispatchable replacement resources when evaluating generation retirement strategies and future resource portfolios.

Q52. What observations can be made regarding dispatchable generation and renewable generation from the Group B analysis?

A52. The Group B analysis demonstrated that both dispatchable and renewable replacement resources can be integrated while maintaining compliance with transmission planning criteria; however, the transmission impacts differed based on the resource type, location, and operating characteristics modeled in the study.

Among the scenarios evaluated, the addition of the 1,500 MW dispatchable generation resource in Change Case 1 produced the lowest overall transmission-related cost outcome, reducing total transmission-related costs by approximately **$265 million** relative to the Base Case. The results indicate that a strategically located dispatchable resource can provide transmission system benefits by reducing transfer requirements, supporting voltage performance, and alleviating transmission constraints that would otherwise require reinforcement.

The renewable replacement resource scenario evaluated in Change Case 4 also performed favorably relative to the Base Case and reduced overall transmission-related costs; however, it did not achieve the same level of transmission cost reduction as Change Case 1 and required higher generator interconnection investments. These results indicate that renewable resources can be integrated without materially increasing transmission reinforcement requirements relative to the Base Case, while also demonstrating that certain strategically sited dispatchable resources may provide additional transmission system benefits under the specific assumptions evaluated.

Accordingly, the study suggests that both dispatchable and renewable resources can support future resource needs, where transmission outcomes depend more on the resource siting, operational characteristics, and interaction with the transmission system than on resource type alone.

Q53. Why do transmission costs continue to trend lower in the 2032 analysis compared to those identified in the 2028 and 2030 analyses?

A53. The primary driver of the reduction in transmission costs between the 2028, 2030, and 2032 analyses is the continued expansion and strengthening of the transmission system through planned transmission reinforcements, including the MISO LRTP Tranche 1 projects assumed to be fully in service in the 2032 study models. These facilities increase transfer capability, improve power flow distribution across the system, and mitigate many of the transmission constraints identified in earlier study years.

The study results demonstrate a steady decline in transmission cost intensity from approximately **$301/kW** in the 2028 Base Case, to approximately **$224/kW** in the 2030 Base Case, and approximately **$159/kW** in the 2032 Base Case. Together, the availability of the MISO LRTP projects and the addition of strategically sited resources contribute to lower transmission reinforcement requirements and improved utilization of the existing transmission network compared to the earlier study horizons.

Q54. What are the limitations of the Group B transmission analysis?

A54. The Group B transmission analysis provides a planning-level assessment of the transmission impacts associated with alternative resource portfolios. While the analysis identifies transmission reinforcement and interconnection costs associated with the evaluated scenarios, it primarily reflects steady-state transmission system performance under the assumptions studied. Additional evaluations, including stability assessments, operational considerations, MISO interconnection studies, and future reliability studies, may identify additional benefits, constraints, or mitigation requirements that are not fully reflected in the transmission cost estimates alone. Therefore, the results should be viewed as one component of the overall evaluation of future resource portfolios and generation replacement strategies.

Group C Scenario Results (C1-C2, 20-year period, y2045)

Q55. What assumptions were included in the 2045 Group C transmission analysis?

A55. The 2045 Group C analysis was performed using two base operating conditions representing summer peak and summer shoulder loading conditions. Both cases incorporated the anticipated 2045 transmission topology and approved transmission build plan and were developed from the Group B Change Case 4 portfolio. The analysis assumed that all remaining non-mitigated carbon dioxide-emitting natural gas generation resources and Tier 1 peaking units were placed offline in the study dispatch to enable renewable generation resources to serve system load under the modeled conditions. The analysis also included the previously modeled CCGT 1 and CCGT 2 proxy resources, each represented by a 1,500 MW CCS-ready dispatchable resource. The purpose of the analysis was to evaluate the transmission

system impacts associated with a deeply decarbonized generation portfolio in the 2045 planning horizon.

Q56. What were the results of the 2045 Group C transmission analysis?

A56. The analysis identified **$1.22 billion** of thermal transmission upgrades, **$784 million** of generation interconnection facilities and **$28 million** of stability-related mitigation costs, for a total of **$2.03 billion** of transmission-related investment, required to support the 2045 transmission system and resource portfolio. The 2045 analysis identified approximately 87 corrective action plans and 334 line miles of transmission reinforcement.

The Group C analysis evaluated a future resource portfolio in which the remaining non-mitigated carbon dioxide-emitting natural gas generation resources and Tier 1 peaking units were placed offline in the study dispatch to enable new dispatchable and renewable generation resources to serve system load. Under these conditions, the study identified lower transmission cost intensity than observed in the earlier study horizons, while maintaining compliance with the applicable transmission planning criteria.

Q57. How much generation was evaluated and what was the resulting transmission cost?

A57. The 2045 Group C analysis evaluated approximately **23,520 MW** of generation additions. The resulting transmission investment equated to approximately **$86/kW** of generation added. This represents the lowest transmission cost intensity observed among the scenarios evaluated in the IRP

transmission analysis and reflects the benefits of a mature transmission system incorporating decades of planned transmission investments and resource development.

Q58. Why were the transmission costs lower in the 2045 Group C analysis than in the earlier study periods and what transmission planning observations can be made from the Group C analysis?

A58. The lower transmission cost intensity observed in the 2045 analysis is primarily attributable to the cumulative effect of transmission infrastructure investments assumed to be in service by the 2045 timeframe. In particular, the MISO LRTP Tranche 2.1 projects are assumed to have reached their respective in-service dates and are fully incorporated into the transmission topology used for the analysis. Together with the previously approved LRTP Tranche 1 projects and other planned transmission reinforcements, these facilities strengthen the transmission network, increase transfer capability, and improve the ability of the system to accommodate generation retirements and replacement resources.

As a result, many of the transmission constraints that would otherwise require mitigation have already been addressed by the planned transmission expansion portfolio. This is reflected in the relatively low transmission investment requirement of approximately **$2.03 billion**, despite evaluating approximately **23,520 MW** of generation additions and placing the remaining non-mitigated carbon dioxide-emitting natural gas generation resources and Tier 1 peaking units offline in the study dispatch. Consequently, the resulting transmission cost intensity of approximately **$86/kW** is substantially lower than that observed in

the earlier study periods and indicates the substantial reliability and transmission planning benefits provided by the MISO LRTP program and other planned transmission investments. The analysis also suggests that future transmission planning should consider not only the quantity of generation added, but also resource location, transmission topology, system strength, and the operational characteristics of the future resource mix. Coordinated planning of generation resources and transmission infrastructure remains an important component of achieving a reliable and cost-effective transition of the generation fleet.

Q59. What are the limitations of the Group C transmission analysis?

A59. The Group C transmission analysis provides a planning-level assessment of transmission system impacts associated with a long-term generation transition through 2045. While the analysis identifies transmission reinforcement, interconnection, and stability-related costs associated with the evaluated scenarios, it primarily reflects steady-state transmission system performance under the assumptions studied. Additional evaluations, including detailed stability assessments, resource operational considerations, future generator retirement studies, and interconnection studies, may identify additional reliability needs or mitigation requirements that are not fully reflected in the transmission cost estimates presented in this testimony. Therefore, the results should be viewed as one component of the overall evaluation of long-term resource planning alternatives.

Q60. What planning considerations should be recognized when interpreting the Group C results?

A60. The Group C results are dependent upon the successful implementation and timely completion of the transmission expansion portfolio assumed in the 2045 models, including the MISO LRTP Tranche 1 and Tranche 2.1 projects and other planned transmission reinforcements. The substantial reduction in transmission cost intensity observed in the 2045 timeframe is closely tied to the availability of these facilities. Delays, scope changes, or modifications to major transmission projects could affect future transmission needs and may require additional analysis to assess alternative mitigation measures or resource replacement strategies necessary to maintain system reliability.

In addition, the Group C results should not be interpreted as a forecast of the exact future resource mix, transmission requirements, or system configuration that will exist in 2045. Rather, the results provide planning-level insight regarding the relative transmission impacts associated with a long-term resource portfolio under the assumptions evaluated.

Q61. Do the Group C results represent the final determination regarding future transmission and reliability requirements?

A61. No. The Group C transmission analysis is intended to inform long-term planning and resource portfolio evaluation and does not represent a final determination of future transmission or reliability requirements. As the 2045 planning horizon approaches, additional transmission planning studies, generator interconnection studies, retirement assessments, stability analyses, and regional reliability evaluations will be required to reflect actual system conditions, resource development patterns, load growth, and transmission project implementation.

Consequently, there remains uncertainty regarding the ultimate transmission and reliability requirements, and future studies may identify additional transmission upgrades, voltage support resources, operational limitations, or other reliability measures beyond those reflected in these planning-level estimates.

Stability Study Results

Q62. Was a transmission system stability analysis performed as part of the 2026 IRP transmission evaluation?

A62. Yes. ITC performed dynamic stability analyses as part of the 2026 IRP transmission evaluation. The analyses included both a 2045 long-term stability assessment and a 2032 sensitivity stability assessment designed to evaluate the impacts of the Monroe Power Plant retirement and alternative replacement resource strategies.

Q63. What assumptions were included in the stability analyses?

A63. The 2045 stability study evaluated the Company's long-term IRP portfolio using future transmission topology that included the MISO LRTP Tranche 1 and Tranche 2.1 projects, the expected generation fleet under summer peak conditions, and by simulating over 800 selected faults. The 2032 sensitivity study evaluated a Base Case with Monroe Power Plant retired and compared two alternative replacement resource sensitivities. 2032 Change Case 1 added approximately 3,000 MW of dispatchable CCGT generation represented by two 1,500 MW units, while 2032 Change Case 2 replaced those resources with approximately 3,000 MW of solar generation capacity, ICAP equivalent, dispatched at approximately 30 percent output. The renewable sensitivity was structured to evaluate transmission and stability performance using installed capacity assumptions consistent with the

planning scenarios evaluated. Because the analysis evaluated system reliability and transmission performance at a specific point in time rather than annual energy production, the solar sensitivity was modeled on an installed-capacity basis rather than an energy-equivalent basis. The 2032 study evaluated more than 1,800 simulated disturbances across a Base Case and two Change Cases using future transmission topology, generation retirement assumptions, replacement resources, and applicable MISO planning models. In addition to the summer peak transient stability assessment, a summer shoulder frequency sensitivity study was performed to evaluate system frequency performance following major generation loss events (Fermi and Blue Water Energy Center).

Q64. What were the results and observations regarding the 2045 stability analyses?

A64. Overall, the studies did not identify widespread transmission stability concerns requiring major transmission reinforcements. No instability issues were observed across the majority of the simulated disturbances, indicating that the evaluated resource portfolio can generally maintain acceptable dynamic performance under the study assumptions. The primary finding was a localized instability condition in northern Michigan associated with low post-fault system strength and inverter-based resource performance. ITC identified a potential mitigation consisting of a 150 MVAR synchronous condenser with an estimated cost of approximately $28 million (DTE Electric 64.8% cost share ratio). Outside of this localized condition, no other stability-related transmission upgrades were identified.

Q65. What were the results and observations regarding the 2032 stability analysis?

A65. The 2032 sensitivity study evaluated a Base Case and two Change Cases representing alternative replacement resource strategies following Monroe Power Plant retirement. No transient voltage dip or voltage recovery violations were identified in any of the study cases. In addition, the simulations demonstrated acceptable damping and stable system performance for the vast majority of the approximately 1,813 disturbances evaluated. One instability event involving the Sumpter Generating Station was identified under an extreme contingency condition; however, no cascading outages were observed, and no mitigation was determined to be necessary. The primary study observation involved high-voltage protection operation at several inverter-based generating resources due to reactive power control model settings. These events were mitigated through control model parameter adjustments, including modification of inverter control and protection system settings, including adjustment of voltage ride-through related parameters, and did not require transmission system reinforcements. The solar replacement resource sensitivity produced results generally consistent with the dispatchable generation sensitivity and did not introduce new stability concerns. The summer shoulder frequency sensitivity analysis also demonstrated acceptable frequency performance, with frequency nadirs remaining above under-frequency load shedding thresholds for the largest generation-loss events evaluated.

Q66. What conclusions can be drawn from the stability analyses?

A66. The stability analyses provide additional assurance that the transmission system can accommodate the resource portfolios evaluated in the IRP while maintaining acceptable dynamic performance under the study assumptions. The studies did not identify widespread transmission stability concerns or the need for major stability-

related transmission reinforcements within the DTE Electric service territory or the broader Michigan Lower Peninsula transmission system. The stability analyses demonstrated acceptable transient voltage recovery, stable dynamic performance, and satisfactory frequency response across the resource sensitivities evaluated. The results also highlight the importance of maintaining adequate system strength, reactive power support, and appropriately tuned inverter-based resource control systems as the generation fleet continues to transition toward higher levels of inverter-based resources. System strength, voltage support, and dynamic performance requirements may be addressed through dispatchable resource capabilities, transmission reinforcements, synchronous condensers, advanced inverter controls, reactive support devices, energy storage systems, or other technologies evaluated through future planning and interconnection studies. Finally, the analyses should be viewed as planning-level evaluations intended to inform the IRP process and do not replace future MISO interconnection studies, Attachment Y evaluations, or other project-specific reliability assessments.

Part III: DTE Electric Final 2026 PCA supported by the Grid Study Analysis

Q67. How were the initial transmission study results considered in the development of the PCA?

A67. The initial transmission study results were used together with other IRP planning analyses to evaluate the transmission implications of alternative resource portfolios. The studies provided insight regarding generation retirement timing, resource siting, large load growth, transmission expansion assumptions, and reliability considerations. These findings were considered during PCA development and informed evaluation of alternative portfolios. Please refer to the Testimony of the

Witness Manning for the additional details on the final 2026 IRP PCA portfolio development.

The final PCA was then separately studied by ITC in 2032 and 2045 cases, labelled Group D in the exhibit A-14, to confirm the transmission impacts and planning-level costs associated with the selected resource portfolio.

Q68. What assumptions were included in the Final PCA transmission analysis?

A68. The Final PCA transmission analysis evaluated DTE Electric's selected PCA resource portfolio in both the 2032 and 2045 study years under summer peak and summer shoulder operating conditions. The 2032 PCA cases were developed from the Group B Base Cases and incorporated the PCA portfolio, while the 2045 PCA cases were developed from the Group C Base Cases and incorporated the PCA portfolio for the long-term planning horizon.

For the 2032 PCA cases, ITC evaluated both summer peak and summer shoulder conditions using the anticipated 2032 transmission topology, load assumptions, generation dispatch assumptions, and planned transmission buildout. The summer peak case assumed 100 percent load, wind dispatched at 20 percent, solar dispatched at 30 percent, Ludington discharging, and battery storage either on stand-by or discharging. The summer shoulder case assumed 70 percent load, wind dispatched at 27 percent, solar dispatched at 30 percent, Ludington pumping, and battery storage charging.

For the 2045 PCA cases, ITC evaluated both summer peak and summer shoulder conditions using the anticipated 2045 transmission topology and the final PCA portfolio assumptions. These cases used the same general dispatch framework as the 2032 PCA cases, with summer peak and summer shoulder conditions intended to test the transmission system under different load, renewable output, Ludington, and storage operating assumptions.

Q69. What were the results of the Final PCA transmission analysis?

A69. The Final PCA analysis identified planning-level transmission and interconnection costs for the 2032 and 2045 PCA study years. For the 2032 PCA, the analysis identified **$1.32 billion** of thermal transmission upgrade costs and **$511 million** of generator interconnection facility costs, for a total transmission-related cost of **$1.83 billion**. No separate voltage upgrade costs or anticipated stability costs were identified for the 2032 PCA case.

For the 2045 PCA, the analysis identified **$2.15 billion** of thermal transmission upgrade costs, **$595 million** of generator interconnection facility costs, and **$28 million** of anticipated stability-related costs, for a total transmission-related cost of **$2.77 billion**. No separate voltage upgrade costs were identified in the PCA results.

The PCA results are also reflected in the transmission reinforcement metrics identified by the study. The 2032 PCA required approximately 80 corrective action plans and 444 line miles of transmission reinforcement, while the 2045 PCA required approximately 148 corrective action plans and 727 line miles of transmission reinforcement.

These results indicate that the PCA can be supported from a transmission planning perspective based on the assumptions evaluated, while also recognizing that the results are planning-level estimates and remain subject to future transmission planning, generator interconnection, retirement, and reliability studies.

Q70. How much generation was evaluated and what was the resulting transmission cost?

A70. The 2032 PCA analysis evaluated approximately **15,743 MW** of DTE Electric generation additions. The total grid study cost of approximately **$1.83 billion** equated to approximately **$116/kW** of generation added.

The 2045 PCA analysis evaluated approximately **23,270 MW** of DTE Electric generation additions. The total grid study cost of approximately **$2.77 billion** equated to approximately **$119/kW** of generation added.

These results show that the PCA transmission cost intensity remains within a relatively narrow range between the 2032 and 2045 PCA cases, even as the total amount of generation additions increases over the long-term planning horizon.

Q71. How does the PCA compare to the alternative scenarios evaluated in the transmission analysis?

A71. The PCA results generally fall within the range of planning-level transmission costs identified across the Group A, Group B, and Group C sensitivity analyses. The 2032 PCA cost estimate of approximately **$116/kW** represents the lowest transmission costs compared to the initial seven-year scenarios evaluated, ranging from

$117/kW to **$191/kW**. The 2045 PCA cost estimate of approximately **$119/kW** remains consistent with the 2032 PCA, despite the portfolio growing from approximately **15,743 MW** to **23,270 MW** of generation additions over the planning horizon. While the 2045 PCA produced higher transmission-related costs than the Group C sensitivity of **$86/kW**, the increase was primarily associated with a limited number of major bulk-electric-system transmission facilities and 345 kV transmission corridors resulting from the final PCA resource siting assumptions and associated transmission flow patterns. The concentration of costs among a relatively small number of major transmission facilities suggests that future optimization of resource siting assumptions, interconnection configurations, and transmission solutions may provide opportunities to reduce a portion of these reinforcement requirements while maintaining the overall reliability objectives of the PCA.

Q72. What transmission planning observations from the sensitivity analyses most influenced the evaluation of the PCA?

A72. The sensitivity analyses demonstrated that transmission outcomes are highly dependent on generation retirement timing, resource siting, transmission expansion assumptions, and large load growth. The analyses also demonstrated that strategically located resources and planned transmission expansion projects can materially influence transmission costs and system performance. These findings informed the Company's evaluation of the PCA.

Q73. What role do dispatchable resources play in supporting transmission system reliability?

A73. The transmission analyses indicate that dispatchable resources can provide transmission system benefits beyond their contribution to energy and capacity needs. Depending on their location and operating characteristics, dispatchable resources can reduce power transfer requirements, support local voltage performance, provide reactive power capability, improve operational flexibility, and reduce or defer certain transmission reinforcement needs.

The Group B sensitivity analysis demonstrated this effect by showing that the addition of a strategically located 1,500 MW dispatchable resource reduced total transmission-related costs relative to the 2032 Base Case. These results informed the PCA evaluation by demonstrating that dispatchable resources may help support transmission reliability and reduce transmission system impacts when they are appropriately located and integrated into the broader resource portfolio.

Q74. What planning considerations emerge as the resource portfolio transitions toward higher levels of inverter-based resources?

A74. As the resource portfolio transitions toward higher levels of inverter-based resources, transmission planning must continue to consider system strength, voltage performance, reactive power support, and dynamic response. The PCA results did not identify separate voltage upgrade costs, but the 2045 PCA results did include approximately **$28 million** of anticipated stability-related costs. This is consistent with the broader study observation that stability and system strength considerations become increasingly important in later study years as the generation mix changes and large number of inverter based resources is integrated.

These considerations do not indicate that inverter-based resources cannot be reliably integrated. Rather, they demonstrate the importance of coordinated resource and transmission planning, appropriate resource modeling, inverter control settings, and future reliability studies to ensure acceptable transmission system performance as the resource mix evolves.

Q75. What transmission-related uncertainties remain associated with implementation of the PCA?

A75. Several transmission-related uncertainties remain associated with implementation of the PCA. These include the timing of generation retirements, actual future large load development, final generator interconnection study outcomes, changes in the MISO interconnection queue, the final scope and timing of required network upgrades, and the successful completion of major transmission projects including MISO MTEP and LRTP facilities.

The PCA transmission analysis provides a planning-level estimate based on the assumptions evaluated. Future changes in resource locations, project schedules, load forecasts, generation dispatch, transmission topology, or MISO study results may affect the ultimate transmission upgrades, interconnection costs, voltage support requirements, stability mitigation, or operational limitations needed to reliably implement the PCA.

Q76. Do the PCA transmission results represent the final determination regarding transmission and reliability requirements?

A76. No. The PCA transmission analysis provides a planning-level assessment intended to support the development of DTE Electric's Integrated Resource Plan. The results do not replace future MISO generator interconnection studies, MISO Attachment Y retirement evaluations, MTEP planning analyses, TO planning studies, or other project-specific reliability assessments.

Future studies will continue to refine the transmission requirements associated with the PCA as actual system conditions, generation retirements, generation additions, load growth, transmission project implementation, and interconnection queue outcomes evolve. Consequently, future evaluations may identify additional transmission upgrades, interconnection facilities, voltage support needs, stability mitigation, operational limitations, or other reliability requirements beyond those reflected in the PCA study results.

Q77. What overall conclusions can be drawn from the transmission analyses supporting the PCA?

A77. Collectively, the Group A, Group B, Group C, and PCA analyses demonstrate that transmission planning is a critical component of enabling DTE Electric's long-term generation transition. The initial sensitivity analyses showed that transmission costs are materially affected by generation retirement timing, replacement resource location and type, large load growth, and the availability of major transmission projects.

The final PCA analysis then confirmed that DTE Electric's selected resource portfolio, which includes strategically located dispatchable generation, renewable

Line No.

resource integration, energy storage deployment, planned transmission expansion, and retirement timing, results in a diverse resource portfolio that balances reliability, transmission efficiency, regional transfer capability and long-term system needs, without relying on any single resource type. The PCA results identified approximately **$1.83 billion** in total transmission-related costs for the 2032 PCA case and approximately **$2.77 billion** for the 2045 PCA case. On a cost estimate basis, those results equate to approximately **$116/kW** and **$119/kW**, respectively. These results provide reasonable assurance that the PCA can be supported from a transmission planning perspective under the assumptions evaluated, while recognizing that final transmission, interconnection, retirement, and reliability requirements will continue to be refined through future MISO and transmission owner planning processes. The value of a diverse resource portfolio identified in the ITC and DTE transmission analyses is consistent with MISO's recently released Futures Series 2 scenarios[8], which continue to rely on a combination of dispatchable generation, renewable resources, storage technologies, and transmission expansion to maintain reliability under a wide range of future conditions.

Part IV: Capacity Import Limit (CIL), Capacity Export Limit (CEL) and other Grid Study Components

Capacity Import/Export Limit Analysis

Q78. What is the Capacity Import Limit (CIL) and Capacity Export Limit (CEL)?

[8] MISO Futures Report Series 2, relevant report pages 47 and 48: https://cdn.misoenergy.org/MISO%20Futures%20Report%20Series%202766529.pdf, accessed September 2026.

A78. The CIL is the maximum amount of generation capacity that can be imported into a MISO Local Resource Zone during peak demand conditions without creating thermal, voltage, or generation deliverability constraints on the transmission system. Conversely, the CEL is the maximum amount of generation capacity that can be exported from a Local Resource Zone without creating transmission constraints. The CIL and CEL are important indicators of the transmission system's ability to support capacity transfers between regions and are used by MISO in evaluating resource adequacy and transmission planning requirements.

Q79. What are the current CIL and CEL values for Michigan?

A79. MISO publishes annual CIL and CEL values as part of its Loss of Load Expectation (LOLE) study process. For the 2026/2027 Planning Year[9], Michigan's Lower Peninsula Local Resource Zone 7 continues to maintain both import and export capability, which serve as the baseline against which future transmission expansions, generation retirements, replacement resources, and other portfolio changes can be evaluated. These seasonal values provide an important measure of the transmission system's ability to support regional capacity transfers.

Table 4 MISO PY 2026-2027 LOLE Study Report, Transfer Analysis:

Season	Monitored Element	Contingency	LRZ7 CIL (MW)	LRZ7 CEL (MW)
Summer 2026	Pere Marquette 345/138 kV Transformer	Keystone – Ludington 345 kV	4,628	5,745

[9] MISO PY 2026-2027 LOLE Study Report: https://cdn.misoenergy.org/PY%202026-2027%20LOLE%20Study%20Report728909.pdf, accessed August 2026.

Line No.

Season	Monitored Element	Contingency	LRZ7 CIL (MW)	LRZ7 CEL (MW)
Fall 2026	Pere Marquette 345/138 kV Transformer	Keystone – Ludington 345 kV	5,193	5,305
Winter 2026-2027	Univ. Pk. N. – P9701 West 345 kV	Dumont – Wilton 765 kV	4,123	5,546
Spring 2027	Argenta – 18OXBY 345 kV	Argenta – Battle Creek 345 kV	5,338	5,497

Q80. Why did DTE Electric request a CIL analysis from ITC as part of the 2026 IRP transmission evaluation?

A80. DTE Electric requested that ITC perform a CIL analysis in response to the Michigan Public Service Commission's IRP filing requirements for Transmission Analysis. Specifically, Section XIII of the IRP Filing Requirements directs utilities to work with their local transmission owner to evaluate transmission options, current import and export limits, potential changes to LRZ import and export capability, and transmission studies that support the proposed resource plan. Consistent with Sections XIII(e), XIII(f), XIII(g), and XIII(h), the Company requested that ITC evaluate how the proposed generation portfolio, transmission expansion projects, large load additions, and other planning assumptions could affect Michigan's future import capability and support future resource adequacy needs.

Q81. What assumptions were evaluated in the CIL analysis?

A81. The analysis evaluated the Base Case portfolio and multiple change cases developed as part of the 2026 IRP transmission assessment for the 2032 Group B, 2045 Group C and PCA scenarios. These studies were focused on the CIL analysis

for the base case and change cases where generation is added and major MTEP and LRTP project are placed in service.

Q82. What were the results of the Capacity Import Limit analysis?

A82. The CIL analysis results are listed in the table below.

Table 5 Grid Study Scenarios – LRZ 7 CIL Test Results

Scenario	FCITC	Area Interchange From MI	Limiting Constraint	LRZ7 CIL (MW)
Group B Base	8,688.1	1,639.2	STYX 345 - PALMNO 345	7,048.9
Group B SC1	9,231.3	3,161.8	LEMOYN 345 - LULU 345	6,069.5
Group B SC3	9,991.1	3,560.9	LULU 345 - MON34 345	6,430.2
Group B SC4	9,581.9	1,413.9	LULU 345 - MON34 345	8,168.0
Group C Base	10,606.0	2,797.2	LULU 765 - LULU 345 TRF	7,808.8
PCA 2032	10099.0	2842.1	NLSNRD 345 – STYX 345	7256.9
PCA 2045	12331.8	5120.0	LULU 765 – LULU 345 TRF	7211.8

The CIL analysis produced import capability values ranging from approximately **6,070 MW to 8,168 MW** across the Group B, Group C, and PCA cases evaluated. These results demonstrate that Michigan's future import capability is influenced by the resource portfolio, transmission topology, transmission expansion assumptions, and the location and operating characteristics of replacement resources.

The 2032 PCA produced a CIL value of approximately **7,257 MW**, while the 2045 PCA produced a CIL value of approximately **7,212 MW**. Both results exceed the current MISO PY 2026-2027 LRZ 7 seasonal import capability values and indicate that the PCA maintains substantial import capability throughout the planning horizon under the study assumptions.

In addition, the results indicate that LRZ 7 remains a net exporter under the evaluated base conditions prior to determination of the First Contingency Incremental Transfer Capability (FCITC). Overall, the study results show improved transfer capability and higher import limits than the current MISO PY 2026-2027 LOLE Study values, reflecting the benefits of future transmission expansion and the resource portfolios evaluated in the study.

Q83. What role do the MISO LRTP Tranche 1 and Tranche 2.1 projects play in future CIL performance?

A83. The MISO LRTP Tranche 1 and Tranche 2.1 portfolios represent a large regional transmission investment intended to improve transfer capability and support the ongoing transformation of the generation fleet across the MISO footprint. The studies demonstrated that LRTP Tranche 1 improves transfer capability and reduces transmission constraints in the 2030 and 2032 study horizons, while the combined benefits of LRTP Tranche 1 and Tranche 2.1 are reflected in the long-term 2045 analyses. As a result, the LRTP projects are an important component of maintaining reliable access to regional capacity and energy resources while supporting future generation retirements and replacement resources. These results demonstrate the important role that regional transmission expansion plays in supporting resource adequacy, improving CIL performance, and reducing transmission costs identified throughout the Company's transmission analyses. In addition to increasing transfer capability, major transmission reinforcements can improve overall transmission system efficiency by reducing congestion and improving power flow distribution across the transmission network as reported by MISO LRTP Tranche 1 Portfolio

Line No.

Detailed Business Case[10] and LRTP Tranche 2 Business Case Metrics Methodology Whitepaper[11].

Q84. How does the new LRTP Tranche 2.1 765 kV transmission backbone benefit Michigan?

A84. The MISO LRTP Tranche 2.1 portfolio includes construction of a new 765 kV transmission backbone that is intended to increase regional transfer capability and strengthen the bulk electric transmission system across the Midwest. For Michigan, this new 765 kV infrastructure improves access to regional energy and capacity resources, increases transmission system flexibility, and supports the integration of new generation resources as the generation fleet continues to evolve.

The 2026 IRP transmission analyses demonstrated that major transmission expansion projects reduce loading on existing transmission facilities, improve transfer capability into Michigan, and lower transmission reinforcement requirements identified in future study horizons. As a result, the LRTP Tranche 2.1 765 kV backbone is expected to provide long-term reliability benefits while supporting future generation retirements, increasing Capacity Import Limit capability, and reducing the need for certain transmission upgrades that would otherwise be required to maintain reliable system operation.

[10] MISO LRTP Tranche 1 Portfolio Detailed Business Case: https://cdn.misoenergy.org/LRTP%20Tranche%201%20Detailed%20Business%20Case625789.pdf, accessed August 2026.
[11] MISO LRTP Tranche 2 Business Case Metrics Methodology Whitepaper: https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf, accessed August 2026.

Q85. Did the transmission analyses evaluate transmission costs associated with accessing out-of-state resources?

A85. 2026 ITC and DTE Grid Study analyses performed for the Company's Integrated Resource Plan focused on evaluating the transmission impacts associated with DTE Electric's proposed resource portfolios, including generation retirements, replacement resources, large load growth, transmission reinforcements, and future CIL capability within Michigan. CIL analyses and evaluation of major regional transmission projects, including the MISO LRTP Tranche 1 and Tranche 2.1 portfolios, provide planning-level insight into Michigan's ability to access regional energy and capacity resources. The analyses demonstrated that regional transmission expansion can increase transfer capability, improve import capability, reduce transmission constraints, and strengthen Michigan's access to resources located elsewhere within the MISO footprint. These factors were considered when evaluating the transmission implications of the resource portfolios assessed in this testimony.

A separate transmission cost study specifically evaluating access to out-of-state resources was not performed as this effort would require additional assumptions and inputs regarding resource location, transmission expansion, and interconnection outcomes across the broader MISO footprint. Acquiring these additional assumptions was outside of the scope for the 2026 ITC and DTE IRP transmission evaluation studies.

Q86. How were the CIL analysis results used in development and testing of the PCA?

A86. The CIL analysis results were one of several transmission assessments used to provide input to and evaluate the feasibility of the PCA. The PCA cases produced LRZ 7 CIL values of approximately **7,257 MW** in 2032 and **7,212 MW** in 2045, indicating that the selected resource portfolio maintains substantial import capability throughout the planning horizon under the study assumptions. These results demonstrate that future transmission expansion, generation retirements, replacement resource locations, and regional power transfer capability all influence the long-term ability to serve customer demand. Together with the steady-state and stability analyses, the CIL results provided additional support that the PCA can be accommodated from a transmission planning perspective while increasing regional transfer capability above current MISO LRZ 7 seasonal import capability levels.

Storage Benefits

Q87. What transmission system benefits can transmission-interconnected energy storage provide?

A87. Energy storage resources interconnected directly to the transmission system can provide several potential transmission system benefits in addition to their capacity contributions. Depending on their location and operating strategy, storage resources may reduce transmission loading during periods of high demand, improve utilization of existing transmission infrastructure, reduce congestion, and increase operational flexibility.

The transmission analyses performed for this IRP assumed storage resources were discharging or available to discharge during summer peak conditions and charging

during summer shoulder conditions. These operating assumptions reflect the ability of storage resources to shift energy over time and support changing system needs.

In addition, energy storage resources are highly flexible, capable of rapidly increasing or decreasing output in response to changing system conditions. Their fast ramping capability can help manage variability associated with load fluctuations and inverter-based renewable generation while providing operational support that is not fully captured in planning-level transmission studies.

The study results identified no voltage-related transmission upgrade costs across the evaluated scenarios, and the stability analyses did not identify any widespread local or regional stability concerns associated with the modeled storage resources and generation portfolios. These results indicate that the storage assumptions utilized in the study were compatible with maintaining acceptable transmission steady state and stability performance under the evaluated conditions.

As the transmission system evolves, storage resources may help improve transmission system utilization, support reliability objectives, and defer certain transmission reinforcements under specific operating conditions. The extent of these benefits is dependent on the size, location, and operating characteristics of the storage resource and would typically be evaluated through project-specific transmission and interconnection studies.

Grid Enhancing Technologies

Q88. What are Grid Enhancing Technologies and how could they help address the transmission challenges identified in the study?

A88. GETs are technologies intended to improve the utilization and performance of the existing transmission system. Examples include Dynamic Line Ratings (DLR), advanced power flow control devices, advanced conductor technologies, and transmission topology optimization tools. These technologies can help improve power flow distribution, alleviate certain transmission constraints, increase operational flexibility, and in some cases defer or reduce the scope of traditional transmission upgrades.

As part of the IRP development process, DTE Electric and ITC discussed several categories of GETs and their potential applicability to the transmission challenges identified in the Grid Study. One technology evaluated was advanced power flow control devices, including impedance-control technologies such as SmartValve. These devices can redirect power flows across the existing transmission system and may help alleviate localized transmission bottlenecks or serve as a bridge solution while larger transmission upgrades are developed. However, DTE Electric and ITC noted that the effectiveness of such technologies is highly dependent on system configuration, contingency conditions, resource locations, and operating assumptions. Additional detailed modeling would be required to evaluate performance under N-1 and N-1-1 conditions, system losses, and other reliability considerations. Because these technologies redistribute existing transmission capability rather than create new capability, they are generally better suited for site-specific evaluations than long-term IRP planning studies.

DTE Electric and ITC also discussed advanced conductor technologies, including high-temperature conductors and reconductoring solutions. ITC indicated that reconductoring may provide a cost-effective alternative to certain transmission line rebuilds and has prior experience utilizing advanced conductor technologies such as Aluminum Conductor Steel Supported (ACSS) conductors. Potential applications may exist on heavily loaded transmission corridors identified in planning studies; however, future implementation costs may also include supporting work such as sag remediation, structure modifications, and related upgrades that are not always fully reflected in planning-level estimates.

Dynamic Line Ratings were also discussed. While DLRs can provide operational value by allowing transmission ratings to better reflect actual weather and ambient conditions, DTE Electric and ITC generally viewed DLRs as an operational tool rather than a long-term transmission planning solution. Although DLRs may improve short-term utilization of existing facilities, long-term reliance on increased loading may affect asset life and outage performance and therefore may not eliminate the need for future transmission reinforcements.

Finally, DTE Electric and ITC discussed transmission topology optimization and network configuration alternatives. These approaches can improve system flexibility and alter power flow patterns through switching arrangements and station configuration changes. However, similar to advanced power flow control devices, topology optimization primarily redistributes power flows rather than increases physical transmission capability. Both companies concluded that uncertainty regarding future resource locations limits the value of extensive

topology optimization studies during the IRP process, but such solutions may be appropriate for future project-specific planning studies when resource locations and transmission needs are better defined.

Overall, DTE Electric and ITC concluded that GETs may provide valuable supplemental tools to improve transmission system utilization and operational flexibility, but they are not a replacement for major transmission expansion projects such as MISO LRTP or MTEP projects. The companies also agreed that GETs are typically evaluated through project-specific processes such as generator interconnection studies, transmission planning studies, MTEP evaluations, load interconnection studies, and other analyses where resource locations and transmission requirements are more clearly defined. Accordingly, GETs should be viewed as a complementary planning option that may help defer, optimize, or reduce certain transmission investments under specific circumstances while supporting reliable integration of future resources, however, they do not eliminate the need for major transmission expansion projects identified through the MISO planning process.

Peaker Sensitivity Analysis

Q89. What assumptions regarding peaking generation were evaluated in the transmission analysis?

A89. The transmission analysis evaluated placing units offline for the two categories of peaking resources. The approximately 434 MW Tier 2 peaking fleet, consisting primarily of resources interconnected to the 24 kV and 41.57 kV subtransmission system and the 120 kV transmission system, were assumed to be offline by 2032.

The approximately 1,060 MW Tier 1 peaking fleet, consisting of larger resources interconnected directly to the 120 kV and 345 kV transmission systems, was assumed to be placed offline to allow Renewable Generation dispatch by 2045.

Q90. What were the transmission impacts associated with placing offline the Tier 2 peaking units?

A90. The Group B base case analysis assumed placing offline the approximately 434 MW Tier 2 peaking fleet with no specific voltage or thermal related upgrade requirements found. These results suggest that offline and unavailable status of the smaller subtransmission-connected peaking resources could be accommodated without materially affecting transmission system performance under the study assumptions.

Q91. What considerations go into decisions to place offline, retire or suspend for the Tier 2 peaking units?

A91. The approximately 434 MW of Tier 2 peaking units are primarily interconnected to the 41.6 kV subtransmission system and portions of the 120 kV transmission system and are frequently used as part of N-1 and N-1-1 contingency mitigation strategies supporting DTE Electric's subtransmission and distribution systems. As a result, placing these units offline, retirement or suspension decisions are not based solely on transmission planning studies. The Company performs specialized individual reliability assessments to evaluate the ability of the distribution electric system to continue meeting reliability requirements following a change of status of these units. In addition, individual economic evaluations are performed to assess the costs and benefits of continued operation, replacement, or retirement. For additional discussion regarding the distribution system reliability analyses

supporting peaker retirement decisions, refer to the testimony of Witness Singh. For additional discussion regarding the economic analyses considered as part of the retirement evaluation process, refer to the testimony of Witness Pratt.

Q92. What insights were gained from placing Tier 1 peaking units offline?

A92. The Group C Base Case analysis assumed the approximately 1,060 MW Tier 1 peaking fleet was unavailable for dispatch under the evaluated scenarios together with the remaining non-mitigated natural gas generation resources. Under these assumptions, the study continued to identify transmission reinforcement and stability-related mitigation needs to support the future resource portfolio. The analysis also highlighted the increasing importance of maintaining adequate system strength, operational flexibility, and other grid-support services as the generation portfolio transitions toward higher levels of inverter-based generation.

Although the Group C analysis was not intended to evaluate the specific reliability contribution of individual peaking units, dispatchable peaking resources can provide operational flexibility that is not fully captured in planning-level transmission studies. Unlike weather-dependent resources, peaking units may be dispatched when needed to support system conditions, respond to unexpected generation or load variations, and help manage localized reliability concerns. As a result, these resources may continue to provide value as part of a diversified resource portfolio even as renewable generation penetration increases.

Q93. Does retirement of the Tier 2 peaking units and placing Tier 1 peaking units offline represent a final determination that those resources can be retired, suspended or placed offline?

A93. No. The Group C transmission analysis provides a transmission planning-level assessment only. These units are directly interconnected to the distribution/subtransmission and transmission systems; therefore, any future decision to retire or suspend these resources would be subject to additional reliability and economic evaluations. Individual retirements or suspensions shall be evaluated through the applicable MISO Attachment Y generator retirement process as well as any Affected System Studies (AFS), which assesses thermal, voltage, stability, and other reliability impacts associated with the proposed retirement.

Q94. Does DTE Electric have any active retirement or suspension requests under the MISO's Attachment Y process?

A94. Several DTE Electric peaking units currently have active retirement or suspension determinations under MISO's Attachment Y generator retirement process. These units include Enrico Fermi Power Plant CTG 11-3 (13 MW), Enrico Fermi Power Plant CTG 11-4 (12 MW), River Rouge Power Plant DG 11 (11 MW), and Saint Clair Power Plant CTG 12 (5 MW). Under the MISO Attachment Y process, a suspension may remain in effect for up to three consecutive one-year periods, providing additional time for evaluation of alternatives, implementation of replacement solutions, or other actions necessary before retirement can proceed. Please see the Testimony of Witness Burgdorf for the details and status of DTE Electric's existing fleet.

Part V: Transmission and Interconnection Considerations for CON

Q95. Are transmission interconnection studies and interconnection costs considered as part of a CON request?

A95. Yes. Michigan Public Service Commission, Case No. U-15896, Filing Requirements and Instructions for CON Applications, Attachment A, Section VII.A.9 (transmission interconnection studies and system modifications) and Section VIII.A.1 (transmission interconnection costs) identify these requirements. The MPSC's CON filing requirements specifically require the identification of the status of any transmission interconnection studies and any expected or required transmission system modifications associated with the proposed projects, including the transmission interconnection costs as part of the interconnection process.

Q96. What projects is the Company seeking CON approval for?

A96. The Company is seeking CON approval for two projects including the Livingston County Project 1,400 MW CCS-ready CCGT and Monroe County Project 700 MW CCS-ready CCGT. Please see Witness Pratt's testimony for the Request for Proposal (RFP) selection process, Witness Stansell for the project description and rationale, and Witness Banks for the project execution details.

Livingston County Project

Q97. Can you describe the interconnection application filed for the Livingston County Project?

A97. Yes. DTE Electric holds an active generator interconnection request through MISO for the Livingston County Project. The project is being studied under MISO queue position J3799 and requests up to 1,452 MW of Network Resource Interconnection Service (NRIS) at the proposed point of interconnection on the ITCT Blackfoot–Madrid 345 kV transmission line. The interconnection request was sized to support the anticipated capability of the generating facility and related project development

assumptions. The Livingston County Project supports the Company's proposed approximately 1,400 MW CCS-ready CCGT facility included in the PCA portfolio.

Q98. What is the status of the Livingston County Project interconnection application queue and study process?

A98. The Livingston County Project is currently progressing through MISO's Definitive Planning Phase (DPP), Phase 2 of the interconnection process as part of the DPP-2025 study cycle. Based on the current MISO schedule, DPP Phase 3 is expected to conclude in July 2027, with GIA execution anticipated in December 2027[12]. The final scope of interconnection facilities required network upgrades, and associated cost responsibilities will be determined upon completion of the DPP process and execution of the GIA.

Q99. How do the interconnection timelines align with the proposed in-service dates for the Livingston County Project?

A99. The Livingston County Project is intended to support the Company's planned CCS-ready CCGT resource included in the PCA portfolio. The project is currently progressing through MISO's DPP-2025 interconnection process, with GIA execution anticipated in December 2027. Based on the current schedule, the interconnection process is expected to support the planned 2031 commercial operation date and to be available to meet Company's capacity and energy requirements in 2032, assumed for the CCS-ready CCGT in the IRP PCA.

[12] MISO DPP Schedule: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Schedule629192.pdf, accessed September 2026.

Q100. Does the Livingston County Project require any transmission system upgrades or modifications to achieve interconnection?

A100. Yes. The preliminary MISO DPP Phase 1 study identified several categories of transmission facilities and upgrades necessary to interconnect the Livingston County Project. These include thermal network upgrades, voltage-related upgrades, deliverability upgrades, interconnection facilities, and Transmission Owner Interconnection Facilities (TOIF). The preliminary study results are rough estimates and are summarized below:

Table 6 MISO DPP-2025 Phase I, J3799 Network Upgrade Cost Estimates

Upgrade Category	Estimated Cost
ERIS Thermal Network Upgrades	$114.0 Million
ERIS Voltage Network Upgrades	$0.7 Million
NRIS Deliverability Network Upgrades	$75.7 Million
Interconnection Facilities	$37.6 Million
Transmission Owner Interconnection Facilities (TOIF)	$4.4 Million
Total	**$232.4 Million**

Q101. What were the primary drivers of the network upgrades identified for the Livingston County Project?

A101. The preliminary MISO DPP Phase 1 study indicates that the majority of the network upgrade costs are associated with thermal and deliverability requirements. Approximately $114 million of the estimated cost is associated with ERIS Thermal Network Upgrades required to address transmission loading impacts. In addition, approximately $76 million is associated with NRIS Deliverability Network Upgrades required to ensure that the project's capacity can be reliably delivered to load under MISO's NRIS criteria. Together, these two categories account for most of the preliminary upgrade costs identified for the project. The final scope and cost

remain subject to refinement through the remainder of the MISO DPP study process and execution of the GIA.

Q102. Are DTE Electric and ITC evaluating opportunities to optimize the interconnection configuration for the Livingston County Project?

A102. Yes. In parallel with the MISO Generator Interconnection Process, DTE Electric and ITC continue to evaluate potential interconnection configuration alternatives and implementation considerations associated with the Livingston County Project. These discussions include consideration of interconnection facility design, constructability, transmission system topology, power flow impacts, and opportunities to efficiently integrate the project into the transmission system. The objective of these efforts is to better understand potential interconnection solutions and support development of a reliable and cost-effective interconnection configuration. Any resulting transmission facilities, network upgrades, cost allocations, and interconnection requirements, however, will ultimately be determined through the applicable MISO Generator Interconnection Process and documented in the executed Generator Interconnection Agreement.

Q103. What risks, if any, exist related to interconnection delays or network upgrade cost uncertainty?

A103. As with any large generation project progressing through the MISO Generator Interconnection Process, uncertainty remains regarding the final scope, cost, and timing of required Network Upgrades and interconnection facilities. Interconnection delays may occur if identified Network Upgrades are complex in scope, require large transmission construction, or are dependent upon other

transmission projects reaching completion. In addition, upgrade costs remain subject to change throughout the DPP process because project withdrawals are common within the MISO interconnection queue. As projects exit the queue, the allocation and scope of Network Upgrades may change, which can increase or decrease the final upgrade costs assigned to individual projects. Consequently, the final interconnection costs and schedules for the Livingston County Project will not be fully established until completion of the DPP process and execution of the GIA.

Monroe County Project

Q104. Can you describe the interconnection applications filed for the Monroe County Project?

A104. Yes. DTE Electric holds two active generator interconnection requests through MISO for the Monroe County Project under queue positions J4024 and J4025. Each interconnection request was submitted for up to 1,499 MW of NRIS to preserve optionality during the project development and interconnection evaluation process. Together, these requests support the Company's proposed approximately 700 MW CCS-ready CCGT facility included in the PCA portfolio. The final interconnection configuration, service requirements, and associated facilities will be determined through the MISO Generator Interconnection Process.

Q105. What is the status of the Monroe County Project interconnection application queue and study process?

A105. The Monroe County Project interconnection requests, J4024 and J4025, are currently scheduled to be studied through MISO's DPP-2026 interconnection cycle, tentatively starting in December 2026. Under the current schedule, DPP Phase 1 is

anticipated to conclude in March 2027, Phase 2 in July 2027, Phase 3 in September 2027, and GIA execution is anticipated in December 2027. The final scope of interconnection facilities, Network Upgrades, cost allocation, and implementation schedules will be determined through completion of the DPP study process and execution of the applicable GIAs.

Q106. How do the interconnection timelines align with the proposed in-service dates for the Monroe County Project?

A106. The Monroe County Project is intended to support the Company's planned CCS-ready CCGT resource included in the PCA portfolio. Based on the current DPP-2026 schedule, GIA execution is anticipated in December 2027, which is expected to support the planned 2032 commercial operation date and to be available to meet Company's capacity and energy requirements in 2033, assumed for a CCGT within the IRP PCA, subject to completion of the interconnection process and implementation of any required interconnection facilities and Network Upgrades.

Q107. Have any transmission system upgrades, modifications, or interconnection costs been identified for the Monroe County Project?

A107. Not at this time. The Monroe County Project interconnection requests, J4024 and J4025, are currently scheduled to be studied through MISO's DPP-2026 interconnection cycle. Because the projects are still in the early stages of the MISO Generator Interconnection Process, preliminary study results are not yet available. The scope of any required interconnection facilities, TOIF, Network Upgrades, and associated costs will be determined through completion of the DPP studies and documented in the applicable GIAs.

Q108. Are DTE Electric and ITC coordinating on potential interconnection solutions for the Monroe County Project?

A108. Yes. In parallel with the MISO Generator Interconnection Process, DTE Electric and ITC continue to evaluate potential interconnection approaches for the Monroe County Project. These discussions include consideration of interconnection facility configuration, transmission system topology, constructability, and other implementation considerations intended to support reliable integration of the project into the transmission system. These efforts may help inform future interconnection solutions as the MISO DPP studies progress. However, the final scope of any required interconnection facilities, TOIF, Network Upgrades, cost allocations, and interconnection requirements will ultimately be determined through the applicable MISO Generator Interconnection Process and documented in the executed GIAs.

Conclusion

Q109. Does this complete your direct testimony?

A109. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

BARRY J. MARIETTA

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF BARRY J. MARIETTA

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Barry J. Marietta Jr. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC within Environmental Management & Safety as a Manager – Environmental Strategy, responsible for our Environmental Permitting and Reporting group.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science degree in Chemical Engineering from Michigan Technological University in 1996.

Q4. What is your professional experience?

A4. I was hired by the Company in July 2003 as an Environmental Engineer stationed at the Warren Service Center (Warren) in Detroit, MI. I was responsible for environmental compliance at that facility. This included waste management, training, spill response, various emergency plans and other compliance-related activities. In addition to my responsibilities at Warren, I was part of the Company's Distribution Operations environmental group, which included spill response activities at various customer and Company locations. In 2008, I was assigned to River Rouge Power Plant (RRPP) as the plant Environmental Engineer. My duties at RRPP included air permit compliance and reporting, ISO 14001 activities, waste management, storage tank compliance as well as assisting with water compliance and reporting activities. During this assignment, I developed a working knowledge

Line
No.

of a fossil fuel-fired power plant. While at RRPP, I began assisting the air permitting group with several air permit applications. In 2010, I transitioned to the air permitting group full-time and was responsible for several air permit applications. In addition, I developed the Company's greenhouse gas (GHG) monitoring plan and began assisting the Monroe Power Plant with the implementation of an air permit related to installing and operating best available control technology (BACT) pollution control equipment. At the end of 2010, I was assigned to Monroe Power Plant as the plant Environmental Engineer.

In 2012, I accepted the position of Supervisor of the Emissions Quality (EQ) Group. I was promoted to Manager in 2016. In 2021, my group expanded to include water permitting and reporting. I am currently the Manager of the Environmental Permitting and Reporting Group.

Q5. What are your current duties and responsibilities?

A5. As Manager of the Environmental Permitting and Reporting Group, I oversee activities to monitor and achieve compliance with State and Federal air and water regulations throughout the Company. In addition, the group provides compliance guidance and reporting support to the Company's business units. The group is also involved with strategy development related to environmental compliance for the Company.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have sponsored testimony in the following cases:

Line No.		
1	U-17319	2014 Power Supply Cost Recovery (PSCR) Plan Case
2	U-17680	2015 PSCR Plan Case
3	U-17767	2015 DTE Electric Rate Case
4	U-17920	2016 PSCR Plan Case
5	U-17920-R	2016 PSCR Reconciliation Case
6	U-18143	2017 PSCR Plan Case
7	U-18403	2018 PSCR Plan Case
8	U-18419	DTE Electric Certificates of Necessity (CON)
9	U-20069	2017 PSCR Reconciliation Case
10	U-20221	2019 PSCR Plan Case
11	U-20222	2019 PSCR Reconciliation Case
12	U-20471	2019 DTE Electric Integrated Resource Plan
13	U-20527	2020 PSCR Plan Case
14	U-20528	2020 PSCR Reconciliation Case
15	U-20826	2021 PSCR Plan Case
16	U-20827	2021 PSCR Reconciliation Case
17	U-21050	2022 PSCR Plan Case
18	U-21051	2022 PSCR Reconciliation Case
19	U-21193	2022 DTE Electric Integrated Resource Plan
20	U-21259	2023 PSCR Plan Case
21	U-21260	2023 PSCR Reconciliation Case
22	U-21425	2024 PSCR Plan Case
23	U-21426	2024 PSCR Reconciliation Case
24	U-21594	2025 PSCR Plan Case
25	U-21595	2025 PSCR Reconciliation Case
26	U-21875	2026 PSCR Plan Case

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. My testimony has several major areas of focus as outlined below:

- I describe the scope and status of significant environmental regulations that impact the Company's power plants, compliance options, costs for compliance, and the impacts on the Company's generation fleet.
- I provide a summary of projected emissions for the Company's Proposed Course of Action (PCA).
- I provide quantitative assessment of the Company's Environmental Justice (EJ) screening and a qualitative assessment of the potential environmental and health impacts of the IRP portfolios on vulnerable communities.
- I provide a summary of the health impact estimates using the Environmental Protection Agency's (EPA) Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool based on the IRP air emissions data.
- I describe the impact assessment performed by the Company based on the emissions projections for particulate matter having a diameter of less than 2.5 micrometers (PM2.5).
- I identify and assess the impact of the PCA on the National Ambient Air Quality Standards (NAAQS) status, including the existing non-attainment areas in the Company's service area.
- I supply testimony to meet the requirements of the Company's Certificate of Necessity (CON) filing including environmental regulations, compliance options, emissions data, and other information associated with the Company's proposed new generation projects.

Q8. Did you provide inputs to the group responsible for conducting DTE Electric's IRP process for the PCA?

A8. Yes. I provided information on environmental regulations that are expected to impact the Company. Information on the impacts of environmental regulations were used by the Company's IRP group in the IRP planning process and associated testimony.

Q9. Are you supporting any exhibits?

A9. Yes. I am sponsoring the following Exhibit:

Exhibit	Description
A-15	Emission Projections Summary Data

Q10. Was this exhibit prepared by you or under your direction?

A10. Yes, it was.

Q11. How is your testimony organized?

A11. My testimony consists of the following sections:

Part I	Environmental Regulations and Compliance Options
Part II	Emissions Projections and Comparison
Part III	Environmental Justice Analysis
Part IV	Impact Assessment
Part V	CON Filing

Line No.

PART I: ENVIRONMENTAL REGULATIONS AND COMPLIANCE OPTIONS

Q12. What are the environmental regulations that the Company is required to comply with and are there specific regulations that are impacting the Company's existing power plants?

A12. Although there are many environmental regulations impacting the continued operation of the Company's existing plants, there are several regulations that have or would necessitate capital investments in order to continue operation up to the currently planned retirement dates. The regulations impacting capital spend at the Company's plants include the following:

- Steam Electric Power Generating Effluent Limitation Guidelines (ELG)
- Coal Combustion Residuals (CCR) Rule
- National Ambient Air Quality Standards (NAAQS)
- Thermal Discharge Regulations (316(a))
- Cooling Water Intake Structure (CWIS) Regulations (316(b))

Effluent Limitation Guidelines

Q13. What are the Effluent Limitation Guidelines (ELGs)?

A13. Effluent Limitation Guidelines are national wastewater discharge standards that are developed by the EPA on an industry-by-industry basis. These are technology-based regulations and are intended to represent the greatest pollutant reductions that are both available and economically achievable for an industry. The EPA first promulgated the Steam Electric Power Generating (SEPG) ELGs in 1974, and amended the regulations in 1977, 1978, 1980, 1982, 2015, 2020, 2024, and 2025. The regulations cover wastewater discharges from steam electric power plants. The Steam Electric ELGs are implemented by incorporation into National Pollutant

Discharge Elimination System (NPDES) permits issued by the Michigan Department of Environment, Great Lakes & Energy (EGLE).

Q14. Can you describe the recent revisions to EPA's ELGs?

A14. Yes. EPA's SEPG ELGs regulate how electric utilities must manage certain wastewaters. On October 13, 2020, the EPA finalized the 2020 ELG Reconsideration Rule (herein referred to as the Reconsideration Rule) which revised some requirements from the 2015 version of the ELG rule. The Reconsideration Rule updated requirements for two specific waste streams produced by steam electric power plants: flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW). The Reconsideration Rule provided additional compliance opportunities by finalizing compliance subcategories, such as for the cessation of coal burning activities. Therefore, steam electric plants can comply with ELG requirements for FGD and BATW by either meeting discharge requirements or those of a subcategory. On March 29, 2023, EPA published a direct final rule (DFR) to update the Reconsideration Rule by extending the date for steam electric power plants to enter the permanent cessation of coal combustion subcategory.

Following the Reconsideration Rule and DFR, the EPA completed a supplemental rulemaking to address discharge limits in the SEPG ELGs following a science-based review of the Reconsideration Rule under Executive Order 13990. The EPA finalized the Supplemental ELG Rule (Supplemental Rule) on May 9, 2024, thereby updating the regulations from the Reconsideration Rule. The Supplemental Rule established new, technology-based effluent limitation guidelines and standards

applicable to FGD wastewater, BATW, Combustion Residual Leachate (CRL), and Legacy Wastewater (LWW), while maintaining the cessation of coal combustion compliance subcategory from the Reconsideration Rule.

Lastly, in 2025, Executive Order 14154 directed the EPA to publish the Deadline Extensions Rule to extend the compliance deadlines promulgated in the Supplemental Rule, update transfer provisions to allow facilities to switch between compliance alternatives and create authority for alternative applicability dates based on site-specific factors. The EPA's Deadline Extensions Rule does not change the underlying discharge requirements established in the Supplemental Rule

Q15. How did the 2020 Reconsideration Rule impact the Company's planning and when must DTE comply with the 2020 Reconsideration Rule, 2024 Supplemental Rule, and 2025 Deadline Extensions Rule?

A15. The Reconsideration Rule provided opportunities for the Company to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in the most cost-effective manner. The EPA set the applicability dates for BATW and FGD wastewater retrofits to be "as soon as possible" beginning October 13, 2021, and no later than December 31, 2025. The Supplemental Rule applicability dates for BATW, CRL and FGD are to be "as soon as possible" beginning July 8, 2024, and no later than December 31, 2029. The Deadline Extensions Rule extended the dates for BATW, CRL and FGD to be "as soon as possible" beginning July 8, 2024, and no later than December 31, 2034.

For facilities such as Monroe Power Plant, pursuing the FGD wastewater Voluntary Incentives Program (VIP) established in the Reconsideration Rule, detailed further below, compliance shall be achieved no later than December 31, 2028. For facilities pursuing the cessation of coal burning activities compliance subcategory from the Reconsideration Rule, detailed further below, compliance shall be achieved no later than December 31, 2028. Compliance schedules for individual facilities and individual waste streams are determined through issuance of new NPDES permits by EGLE.

For Monroe Power Plant, the NPDES permit contains compliance deadlines of December 31, 2025, for BATW on Monroe Power Plant Units 1 and 2 and December 31, 2028, for FGD wastewater for all four Monroe Power Plant units and BATW on Monroe Power Plant Units 3 and 4. For Belle River Power Plant, the NPDES permit contains a compliance deadline of December 31, 2028, for BATW. The Deadline Extensions Rule made changes to previous ELG rules; however, the changes are not applicable to the Company's current ELG compliance strategy.

Q16. If the Supplemental Rule and Deadline Extensions Rule extended applicability dates for best available technology-based compliance for FGD and BATW, would the Company change its current compliance deadlines?

A16. No. The Company pursued the best available technology compliance option for BATW at Monroe Power Plant Units 1 and 2. During development of the Supplemental Rule by EPA, the Company remained subject to the requirements of the Reconsideration Rule as EPA required permitting authorities to continue implementing these requirements while EPA undertook the rulemaking process.

The BATW compliance deadline for Units 1 and 2 in the Monroe Power Plant NPDES permit was December 31, 2025. Prior to the Supplemental Rule being finalized, the Company had already made strategic and financial decisions regarding implementation for the project to meet the deadline in the NPDES permit. The Company met the December 31, 2025 compliance date. Therefore, compliance deadlines in the Reconsideration Rule and Deadline Extensions Rule are not applicable. For FGD wastewater compliance at Monroe Power Plant Units 1 and 2, the Supplemental Rule or Deadline Extensions Rule did not change the VIP compliance discharge requirements or deadlines. See Q21 for more details.

The Supplemental Rule supported the Company's ongoing compliance path for BATW and FGD wastewater compliance at Monroe Power Plant and affirmed that installation of BATW projects by the end of 2025, and FGD wastewater projects by the end of 2028, are needed for Units 1 and 2. While the Supplemental Rule did not change the projects that are currently required for FGD wastewater and BATW compliance, the Company is evaluating effects on future compliance projects for CRL and LWW identified by the rule.

Q17. What is the Company's plan to comply with the Reconsideration Rule, Supplemental Rule, and Deadline Extensions Rule?

A17. The Deadline Extensions Rule is not applicable due to the Company's current compliance strategy. The Company will pursue two compliance pathways to achieve compliance under the Reconsideration Rule and the Supplemental Rule for BATW and FGD wastewater. The first is to design and engineer new technologies that comply with the ELG requirements for BATW and FGD wastewater. The

second is to pursue a compliance subcategory for BATW and FGD wastewater that the EPA established within the Reconsideration Rule. The compliance subcategories established in 2020 for the Reconsideration Rule were maintained and not impacted by the Supplemental Rule or the Deadline Extensions Rule.

Q18. What compliance subcategories established within the Reconsideration Rule, and maintained by the Supplemental and Deadline Extensions Rules, are the Company pursuing?

A18. One subcategory allows companies to attain compliance with the ELGs for both BATW and FGD wastewater by ceasing coal combustion activities, which includes retiring coal-fired units or converting units to other fuels. If companies certify that unit(s) will cease the use of coal, they can continue to operate those units until the specified retirement date, which is required to be no later than December 31, 2028. For the electrical generating unit(s) that certify under this subcategory, companies need to maintain the existing standard limits already in effect for BATW and FGD wastewater discharges until the day of unit shut down. As detailed in Q22 and Q23, the Company is pursuing this subcategory for compliance at Monroe and Belle River Power Plants.

In addition to the cessation of coal combustion activities subcategory, the Reconsideration Rule also provides a subcategory specific to FGD wastewater. The Reconsideration Rule established Best Available Technology (BAT) standard discharge limits for FGD wastewater discharges, and further, finalized a subcategory called the Voluntary Incentives Program (VIP). Under the VIP, companies could choose to meet more stringent effluent limits established by the

EPA in the Reconsideration Rule. If a company chooses the VIP option, then the applicability date for FGD wastewater compliance will be no later than December 31, 2028. The Supplemental Rule and Deadline Extensions Rule did not change the compliance subcategories for ceasing coal combustion activities and VIP from the Reconsideration Rule. As detailed in Q23, the Company is pursuing this subcategory for FGD wastewater compliance at Monroe Power Plant. The Company's compliance strategy pursued under the referenced rules is provided in more detail in the answers to Q19 through Q21 below.

Q19. How does a company pursue compliance under a compliance subcategory from the ELG Rules?

A19. To establish compliance for either of these subcategories, companies were required to submit a Notice of Planned Participation (NOPP) to EGLE before the specified deadlines established in the 2020 Reconsideration Rule and the 2023 DFR. Once submitted, companies are required to submit annual progress reports to EGLE to ensure the commitment of compliance under the subcategories.

Q20. Did the Company submit an NOPP filing for ELG compliance subcategories?

A20. Yes. Three NOPPs were submitted. A cessation of coal NOPP was submitted for Belle River Power Plant on October 13, 2021. A VIP NOPP was submitted for Monroe Power Plants Units 1 and 2 on October 13, 2021. Lastly, a cessation of coal NOPP was submitted for Monroe Power Plants Units 3 and 4 on April 27, 2023.

Q21. Why did the Company submit the VIP NOPP for FGD wastewater ELG compliance for Monroe Power Plant Units 1 and 2?

A21. For FGD compliance, the Company evaluated a suite of technology options that would achieve both BAT and VIP compliance requirements for FGD wastewater ELG compliance. At the time of NOPP development in 2021, the Company was still evaluating the suite of potential compliant technologies with the Reconsideration Rule. To ensure that the Company could continue to evaluate all available technologies, including those that achieved VIP compliance, the decision was made to submit the VIP NOPP. By submitting the VIP NOPP, it allowed the Company to continue evaluating all available technologies on the market and not just technologies capable of achieving BAT.

Since submittal, the Company has developed a strategy for VIP compliance. Consistent with the Order in the Company's 2022 IRP (Case No. U-21193) and the PCA in this IRP, Monroe Power Plant Units 1 and 2 will continue to operate until 2032, and FGD wastewater ELG compliance will be achieved by December 31, 2028, for those two units by meeting the VIP requirements. As detailed above, Monroe Units 3 and 4 will achieve compliance via cessation of coal combustion as indicated by the Company's April 27, 2023, NOPP submittal.

Q22. What is the Company's compliance strategy for Belle River Power Plant?

A22. Belle River Power Plant operates without FGD, so there is no FGD wastewater. During operation on coal, bottom ash is collected using transport water. The Reconsideration Rule and the Supplemental Rule would require the Company to comply with BATW discharge requirements if operating on coal. The Company submitted an NOPP on October 13, 2021, for the cessation of coal at Belle River Power Plant. Belle River Unit 1 was converted to natural gas in 2025 and is

currently operating as a natural gas-fired unit. Consistent with the PCA in this IRP, Belle River Unit 2 will be converted to natural gas in late-2026 and will operate as a natural gas-fired unit in 2027 and beyond.

Q23. What is the Company's compliance strategy for Monroe Power Plant?

A23. The Company's compliance strategy for Monroe Power Plant Units 1 and 2 differs from the strategy for Monroe Units 3 and 4.

For Monroe Power Plant Units 1 and 2, for BATW, the Company achieved compliance at the end of 2025 as detailed in Q16 and has terminated the use of water for bottom ash transport. For Monroe Units 1 and 2 for FGD wastewater, the Company is pursuing VIP compliance. The Company plans to install a VIP-compliant option no later than December 31, 2028.

For Monroe Power Plant Units 3 and 4, the Company submitted a cessation of coal compliance subcategory NOPP on April 27, 2023. Consistent with the PCA in this IRP, and the last IRP order, Monroe Power Plant Units 3 and 4 will retire in 2028. Based on the cessation of coal combustion NOPP and the planned retirements, no further action will be required.

Q24. Does EPA's Supplemental Rule affect or alter planned capital projects to comply with ELG requirements?

A24. No. The Supplemental Rule did not change the need for the BATW and FGD wastewater capital projects for Monroe Units 1 and 2. Both projects rely on technology options that will result in no discharge of BATW or FGD wastewater.

Zero liquid discharge (ZLD) technologies will always be compliant with ELG requirements as there is no discharge to regulate. Further information on costs associated with ELG compliance included in this IRP can be found in Q43 below.

Q25. Could EPA's Supplemental Rule and/or Deadline Extension Rule impose new requirements on the Company beyond the compliance projects identified above?

A25. Yes. The Company is currently evaluating the compliance obligations that could impact certain LWW and CRL at our SEPG sites and licensed CCR landfills. Potential outcomes of the Supplemental Rule could include new or updated leachate treatment systems at the Company's CCR landfills. The Deadline Extension Rule does not impose new standards on ELG waste streams, but it does extend the compliance deadline for CRL from December 31, 2029, to December 31, 2034.

Coal Combustion Residuals

Q26. Can you describe the CCR Rule and recent amendments?

A26. Yes. The EPA's CCR Rule regulates how electric utilities must manage and dispose of CCR in landfills and impoundments. The CCR Rule was initially promulgated by EPA in 2015, with various amendments since that have supported implementation of State programs and forced closure of certain CCR impoundments considered unlined. Recent amendments to the CCR Rule include the final 2024 Legacy CCR Rule and the 2026 Deadline Extension Rule. The 2024 Legacy CCR Rule broadly expanded the regulations governing CCR disposal to include previously unregulated CCR that exists at certain facilities. Specifically, the EPA established regulatory requirements for two new classes of CCR units:

legacy CCR surface impoundments at inactive utilities and any other non-containerized accumulation of CCR known as CCR Management Units (CCRMU) at certain facilities. Compliance activities associated with the 2024 Legacy CCR Rule are discussed further in questions 33-34 below. The 2026 Deadline Extension Rule extends certain deadlines contained in the 2024 Legacy CCR Rule, including facility evaluation report deadlines and CCRMU implementation deadlines.

Q27. Can you describe how the EPA's 2020 amendments to the CCR Rule affect the Company locations with unlined CCR surface impoundments?

A27. Yes. On August 28, 2020, the EPA published an amendment to the CCR Rule (the Part A Rule) that required all unlined surface impoundments to cease receipt of waste and initiate closure as soon as technically feasible but by no later than April 11, 2021. This amendment also provided utilities with the ability to request site-specific alternative closure deadlines through a demonstration process requiring EPA approval. On November 12, 2020, the EPA published an additional amendment to the CCR Rule (the Part B Rule) that allowed utilities the opportunity to demonstrate that their unlined surface impoundments have an alternate liner system that is as protective as a CCR Rule-compliant liner system. The demonstration processes included in the Part A and Part B Rules required EPA approval to continue operating CCR surface impoundments. The various applications submitted by the Company in accordance with the Part A Rule and Part B Rule have been withdrawn, and all Company owned and operated unlined CCR surface impoundments have ceased receipt of waste and have either completed closure or are progressing through closure.

Q28. Can you describe the Company's strategy for closure of the Monroe Fly Ash Basin (FAB)?

A28. Yes. The Company converted the existing wet fly ash handling system at Monroe Power Plant to a dry system in accordance with the 2015 ELG Rule. The Monroe FAB received its last known shipment of waste on December 29, 2023. The Company submitted a Notification of Intent to Close the FAB as required. As discussed in that notification, the Company has initiated closure within the appropriate regulatory timeframes.

The Company is closing the Monroe FAB in place with an alternative cover system designed to meet both State and Federal requirements. Closure activities will require drainage (unwatering of free water and dewatering of separable pore water) to stabilize the existing CCR material, grading of the CCR material to drain, and installation of the final cover system over the CCR material to minimize erosion and infiltration. Unwatering and dewatering activities will be performed throughout the closure project, as necessary, to manage water within the FAB. Closure activities, including closure design, permitting, contracting, and studies are underway. Closure construction is anticipated to happen in phases and be complete by the end of 2030.

Q29. Please explain why the Monroe FAB closure project is necessary and what are the required closure timeframes?

A29. The Monroe FAB is an existing unlined CCR surface impoundment per the CCR Rule (40 C.F.R. §257.71(a)). The Monroe FAB ceased receipt of waste as of

December 29, 2023, and initiated closure within 30 days to comply with the CCR Rule (40 C.F.R. §257.102(e)(1)).

To ensure compliance with the closure timeframes outlined in the CCR Rule (40 C.F.R. §257.102(f)(1)), the Company must complete closure within five years of ceasing receipt of waste and commencing closure activities. The deadline for completing closure may be extended if the Company can demonstrate that it was not feasible to complete closure within the required timeframe due to factors beyond the company's control (e.g. weather-related events or the characteristics of the unit such as volume of CCR or acreage of the unit). The Company currently anticipates the need for one two-year extension due to the size and complexity of the closure.

Q30. Can you describe the Company's strategy for closure of the Monroe Bottom Ash Basin (BAB) and the status?

A30. Yes. The Company ceased receipt of CCR at the Monroe BAB prior to the effective date of the 2015 CCR Rule. On December 11, 2015, the Company prepared, and placed in the facility's operating record, a notice of intent to initiate closure in accordance with the CCR Rule (40 C.F.R. §257.100). The Monroe BAB was therefore considered an inactive CCR surface impoundment. Section 257.100 was later remanded by the EPA, subjecting inactive CCR surface impoundments to all the requirements applicable to existing CCR surface impoundments but on an alternative timeline. In April 2020, it was determined that the Monroe BAB did not meet the requirements of §257.60 (placement above the uppermost aquifer) and was subject to closure under the requirements of §257.101(b)(1)(i). Therefore, it

had to cease receipt of both CCR and non-CCR material as soon as technically feasible, but no later than April 11, 2021, and close in accordance with §257.102.

The Company timely ceased receipt of non-CCR waste streams at the Monroe BAB and initiated closure on October 21, 2020. The Company completed removal of the majority of CCR in October 2024. As part of the removal verification process, a quality check study revealed several small areas in the Monroe BAB where CCR remained. The Company is taking additional action to address those remaining areas of CCR with all material expected to be removed by late 2026.

Once closure by removal is complete at the Monroe BAB, two rounds of samples will be collected from the groundwater monitoring well network to ensure that groundwater constituent concentrations fall below the groundwater protection standards. Upon making that demonstration, the Company estimates preparing the notification of completion of closure of the Monroe BAB in late 2027.

Q31. Please explain why the site improvements at Sibley Quarry Landfill (SQLF) were necessary to support CCR Rule compliance?

A31. Improvements to the infrastructure at SQLF have been made to enhance the storage capability to accept the CCR material from the Monroe BAB and CCR from Monroe Power Plant operation. These improvement projects were necessary as the Monroe FAB could not accept CCR beyond 2023. SQLF has ample permitted capacity and was therefore selected as the disposal location for the CCR material removed from the Monroe BAB and for CCR from plant operations.

Q32. Can you describe how the final 2024 Legacy CCR Rule and other EPA action could affect or alter planned capital projects to comply with the previously promulgated CCR Rule?

A32. Yes. On May 8, 2024, the EPA published a final rule titled "Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments". This final rule established regulatory requirements for inactive surface impoundments at inactive facilities, including groundwater monitoring, corrective action, closure, and post-closure care requirements for all CCRMU at regulated CCR facilities. Importantly, the rule applies to previously unregulated CCR. The 2024 Legacy CCR Rule also affects future capital projects being planned to comply with the pre-existing CCR Rule. Specifically, the definition of "liquids" and the requirement to eliminate free liquids established in §257.102(d)(2)(i) is now applicable to existing CCR landfills, where previously it had only been applicable to CCR surface impoundments. Practically speaking, this means there will be increased efforts associated with closing existing CCR landfills due to the expanded requirement to perform dewatering activities.

Q33. Can you describe how the 2024 Legacy CCR Rule affects current and future capital projects?

A33. Yes. As mentioned above, the Legacy CCR Rule imposes new requirements on previously unregulated CCR. The Legacy CCR Rule establishes two new classes of regulated CCR units under the Federal CCR rules: legacy CCR surface impoundments and CCRMU. The Company does not own any legacy CCR surface impoundments and therefore the impact of the Legacy CCR Rule on the Company is focused on CCRMU. The rule requires owners/operators of all active facilities to

undertake a site assessment to identify CCRMUs containing one ton or more of CCR. Any CCRMU that contains 1,000 tons or more of CCR would be subject to the groundwater monitoring, corrective action, closure, and post-closure care requirements of the CCR Rule. Any CCRMUs that fall below the 1,000-ton threshold would not immediately be subject to the requirements of the CCR Rule but would instead be subject to future permitting to determine whether additional actions are needed. The Company is currently evaluating the magnitude of CCRMU at SQLF and Belle River, St. Clair, Delray, River Rouge, Trenton Channel, and Monroe Power Plants.

Q34. Does the 2026 Deadline Extension Rule affect work accomplished to comply with the 2024 Legacy CCR Rule?

A34. No. The substance of the 2024 Legacy CCR Rule, as it related to compliance obligations for CCRMUs remains unchanged by the updates, and therefore, the actions taken to date by the Company to comply with the 2024 Legacy CCR Rule were necessary to support compliance. On February 10, 2026, the EPA published the 2026 Deadline Extension Rule that extends certain deadlines contained in the 2024 Legacy CCR Rule. Key changes include the extension of Facility Evaluation Reports Part 1 and 2 to February 9, 2027, and February 9, 2028, respectively. Other key changes include the extension of groundwater monitoring system / detection monitoring programs to February 10, 2031, closure and post-closure care plans to August 11, 2031, initial groundwater monitoring reporting to January 31, 2032, and initiation of closure to February 9, 2032.

National Ambient Air Quality Standards

Q35. Can you describe the NAAQS regulations and their impact on the Company?

A35. Yes. The Clean Air Act (CAA) requires that the EPA set national ambient air quality standards (NAAQS) for six pollutants: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). NAAQS are set by the EPA at levels deemed to be protective of public health and the environment. The standards are reviewed periodically and may be revised based on that review. Areas in which pollutant levels in ambient air are below the NAAQS are designated as attainment, while areas with levels above the standards are designated as non-attainment. As the standards are specific to a geographic area, not a point source, the plans to meet the standards require collaboration between the state regulatory agency, in this case EGLE, and the specific emitting sources within the defined non-attainment area.

In 2010, the EPA lowered the one-hour SO_2 NAAQS, resulting in areas in Wayne and St. Clair Counties being designated as non-attainment in 2013. The areas included the Company's River Rouge, Trenton Channel, St. Clair and Belle River Power Plants. The Company accepted lower emission limits for some facilities, retired other facilities, and is converting Belle River Power Plant to natural gas. These efforts, along with the future retirements of the Monroe Power Plant units will eliminate SO_2 NAAQS from impacting the Company's operations.

Q36. Can you discuss the current status of the ozone and PM2.5 NAAQS and what impacts there may be on the Company's facilities?

A36. Yes. Ozone NAAQS have undergone updates and changes in recent years. In 2015, the NAAQS for ozone were lowered from 75 parts per billion (ppb) to 70 ppb. As a result, a seven-county area of southeast Michigan (SEMI) was designated as non-attainment for ozone. This area includes many of the Company's electric generating facilities. The non-attainment area is impacted by many other industries and factors and is not specific to the Company's facilities or operations.

In January 2022, EGLE submitted a request to EPA that the seven-county ozone non-attainment area in SEMI be redesignated to attainment. In May 2023, EPA finalized a clean data determination (CDD) and redesignation to attainment for the area. EPA's redesignation was challenged at the U.S. Court of Appeals for the Sixth Circuit in July 2023. The area remained "Attainment – Maintenance" while the challenge was pending. In December 2025, the Court ruled the redesignation invalid. The Court issued a mandate on February 24, 2026, effectively implementing its ruling and returned the seven-county area to a "Moderate" non-attainment designation. Based on the mandate, EGLE developed an "Addendum to Request for Redesignation to Attainment" which was submitted to EPA. On July 24, 2026, EPA proposed redesignating the southeast Michigan area as attainment for ozone. The proposal will go through a public comment period. The Company will monitor the status of the area and proceed accordingly. The emission reductions associated with the Company's PCA include further reductions in ozone through decreases in NOx and VOC emissions. At this time, it is not believed that additional emissions reductions from the Company's facilities would be required for ozone purposes.

In early 2024, EPA lowered the primary annual PM2.5 NAAQS from 12 ppb to 9 ppb. The Final Rule was challenged by a coalition of states. The challenges to the Final Rule were held in abeyance pending EPA's reconsideration of the Final Rule. In late-2025 EPA filed a motion requesting that the D.C. Circuit Court vacate the Final Rule. In June 2026, the Court issued a ruling which upheld the Final Rule. Based on the requirements of the Clean Air Act, the Final Rule, issued in 2024, required EPA to designate areas as attaining or violating the revised NAAQS by February 7, 2026. Due to the ongoing litigation and reconsideration, EPA has not taken action on designations under the primary annual PM2.5 NAAQS at this time. On July 17, 2026, the U.S. District Court for the Northern District of California issued an order finding that EPA failed to perform its duty to promulgate area designations for the 2024 PM2.5 NAAQS and required EPA to finalize these designations by February 6, 2027. The Company will monitor designations under the 2024 PM2.5 NAAQS and assess impacts as future actions are taken by EPA.

Thermal Discharge Regulations

Q37. What are the thermal discharge regulations?

A37. The thermal discharge regulations under Section 316(a) of the Clean Water Act (CWA) regulate heated discharges from processes, including power plants, into Waters of the United States (WOTUS) through the National Pollutant Discharge Elimination System (NPDES). Company facilities with thermal discharges are regulated by EGLE through the NPDES permitting process. The Company's facilities impacted by 316(a) are outlined below.

Q38. What are the impacts of the 316(a) regulations on the Company's operations?

A38. There are various impacts to the Company's facilities depending on current and future operation. The Fermi 2 power plant and Blue Water Energy Center (Blue Water or BWEC) have installed cooling towers and are compliant with the 316(a) regulations. Greenwood Energy Center (Greenwood) uses cooling sprays in the water discharge loop to cool water to levels that are compliant with 316(a) regulations with no further controls.

At Belle River Power Plant, a rapid mixer diffuser is installed in the mixing zone of the plant discharge outfall to the St Clair River. The diffuser is considered BAT and there are no additional controls required. The conversion of Belle River Power Plant to natural gas also reduces the water use by the plant as well as the associated thermal impact on the plant's water discharge on WOTUS. The BWEC discharge also uses this outfall.

The current Monroe Power Plant NPDES permit includes a limit on thermal discharge. The permit also includes a limit on the final discharge temperature effective December 2027. The discharge temperature limit includes a condition which allows EGLE to modify the facility's temperature requirements based on a review of a 316(a) thermal demonstration. The Company completed a thermal study at Monroe Power Plant, as well as a reference site, in 2025. This included studying temperatures as well as a survey of biological and other parameters to determine whether there is an impact on the aquatic ecosystem in the area. Based on the results of that study, the Company applied for a modification to the NPDES permit in August 2026 which included a request for modification of the permit to eliminate the temperature limit at the final discharge and continue monitoring of the discharge

temperature as is currently done with no final discharge temperature limit. This modification is supported by the thermal study which was included in the permit modification application. The study results, combined with the proposed retirement schedule for Monroe Power Plant included in the PCA in this case, will reduce the thermal impact on the plant's water discharge on the associated WOTUS. Beyond the previously incurred cost of the biological studies at Monroe Power Plant, additional costs associated with 316(a) regulations, if any, are unknown at this time.

Cooling Water Intake Structure (CWIS) Regulations

Q39. What are the cooling water intake structure (CWIS) regulations?

A39. The EPA finalized regulations on CWIS under Section 316(b) of the Clean Water Act (CWA) in August 2014 for power plants and other facilities. The regulations affect cooling water intake at existing facilities in two main ways: first, existing facilities are required to reduce fish impingement on the screens; second, existing facilities are required to conduct studies to determine whether and what controls would be required to reduce the number of aquatic organisms entrained by the cooling water system. CWIS at Company facilities are regulated by EGLE through the NPDES permitting process.

Q40. What are the impacts of the 316(b) regulations on the Company's operations?

A40. There are no expected impacts on Fermi 2 due to the use of a closed-cycle cooling system at the plant. Currently, Greenwood plans to limit cooling water intake to less than two million gallons per day (MGD) and will not be impacted by the 316(b) regulations.

Belle River and Monroe Power Plants use once-through cooling systems, which entail taking in non-contact cooling water, then discharging it back to the body of water with no recirculation. The CWIS at these plants are equipped with screens that prevent debris from being taken into the plant systems. The impact of 316(b) at Belle River Power Plant is expected to be minimal based on the cooling water intake design. Additionally, the conversion of Belle River Power Plant to natural gas reduces the water intake needed at the plant and any associated impact.

The Company's expectation is that Monroe Power Plant will be required to install new cooling water intake screens and install a fish return system to comply with 316(b) regulations. Through the retirements of Units 3 and 4 proposed by the PCA in this case, the Company will avoid capital spend for 316(b) compliance on those units. The capital spend for 316(b) compliance for all four units at the plant was projected to be $81 million, while the cost for two units was projected at $57 million. The estimates are several years old and costs for installation of equipment related to 316(b) are expected to have gone up since. It is unknown at this time what costs for entrainment may be incurred by the Company for Monroe. These costs will also be reduced by the proposed retirements of Units 3 and 4. These costs and compliance requirements associated with 316(b) will be incorporated through the NPDES permitting process.

Greenhouse Gas Regulations

Q41. Can you discuss the current status of Federal carbon dioxide (CO_2) and greenhouse gas (GHG) regulations?

A41. Yes. Since 2015, several different EPA Administrations have proposed varying regulations related to CO_2 and/or GHG emissions. There is a long history of legal challenges, reconsideration, and other actions related to these regulations.

On May 23, 2023, the EPA published a proposed rule proposing five separate actions under section 111 of the CAA. The proposal was titled "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired EGUs" and was finalized on April 25, 2024. The final rule included standards for existing and new units depending on size, utilization, and fuel type. The final rule required coal unit retirement by January 1, 2032 unless the unit began cofiring at least 40% with natural gas or installed carbon capture and storage (CCS) at 90% CO_2 capture. Cofiring of natural gas and/or installation of CCS would allow for further operation depending on the retirement date. The final rule also included a requirement for new base-load natural gas-fired plants to have CCS starting in 2032.

On June 11, 2025, the EPA published a rule to repeal the 2024 standards entitled "Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units". The rule would eliminate and/or revise the GHG emission standards for fossil fuel-fired power plants promulgated under CAA Section 111 in both 2015 and 2024, codified at 40 C.F.R. Part 60 Subparts TTTT, TTTTa, and UUUUb. The EPA published the repeal rule as a "Primary Proposal" and "Alternative Proposal". The Primary Proposal finds that GHG emissions from fossil fuel-fired power plants "do not contribute significantly to dangerous air

pollution" under the meaning of CAA Section 111, and, on this basis, repeal all requirements under Subparts TTTT, TTTTa, and UUUUb. The Alternative Proposal would repeal a narrower set of requirements, including emission guidelines for existing sources under Subpart UUUUb and CCS-based requirements under Subpart TTTTa.

On September 14, 2026, EPA finalized the Alternative Proposal and proposed a full repeal of GHG-based regulations. EPA proposes that CAA Section 111 does not authorize the EPA to regulate power plant emissions based on global climate change concerns. The repeal proposal is required to go through public comment. The Company will monitor the regulation and potential legal challenges to determine what, if any, impact there is to the Company's operations.

Other Environmental Regulations

Q42. Are there other environmental regulations that the Company has considered but do not have a large impact on the Company's IRP planning?

A42. Yes. There are many other state and federal environmental regulations that the Company complies with on an ongoing basis which have been considered in this IRP. Unlike the environmental regulations previously discussed in my testimony, these are regulations that are not expected to impact operation or planning in a significant or incremental way. Some of those are listed below.

- Cross-State Air Pollution Rule (CSAPR)
- Greenhouse Gas Reporting Program (GHGRP)
- Regional Haze
- Boiler Maximum Achievable Control Technology (MACT)

- Mercury and Air Toxics Standards (MATS)
- National Environmental Policy Act (NEPA)

Q43. What are the overall impacts of compliance with the environmental regulations discussed in your testimony on the future of DTE Electric's coal-fired power plants?

A43. The Company's currently operating power plants have installed equipment to be compliant with current regulations. Although there is uncertainty around the status of some environmental regulations, and the final timing of applicability and deadlines in some cases, the regulations discussed in my testimony do impact some of the Company's plants. The ELG, CCR, 316(a), and 316(b) regulations require some capital spend for compliance as previously described. The Company has developed cost estimates for these regulations for projects that are in various states of design, engineering, and implementation. A summary of the anticipated capital costs for compliance proposed in the PCA in this case is outlined in Table 1 below.

Table 1 – Capital Costs for Environmental Compliance – 2027-2046

Project	Estimated Cost ($ million)
ELG – Monroe FGD WW	$7
CCR – Monroe Fly Ash Basin	$249
CCR – Legacy CCR	$174
CCR – Sibley Quarry Closure	$51
Total	$481

PART II – EMISSIONS PROJECTIONS AND COMPARISON

Q44. Has the Company projected emissions for the Company's generating units for the portfolios outlined in this filing?

A44. Yes. As outlined in Witness Manning's testimony, the Company modeled four portfolios in this IRP as follows:

- Portfolio 1: previously approved portfolio run in the Michigan Integrated Resource Planning Parameters (MIRPP) business as usual (BAU) scenario (optimized through the current study period)
- Portfolio 2: the Company's proposed course of action (PCA) portfolio run in the MIRPP BAU scenario
- Portfolio 3: optimized portfolio in the MIRPP BAU scenario
- Portfolio 4: optimized portfolio in the MIRPP BAU scenario with high load sensitivity

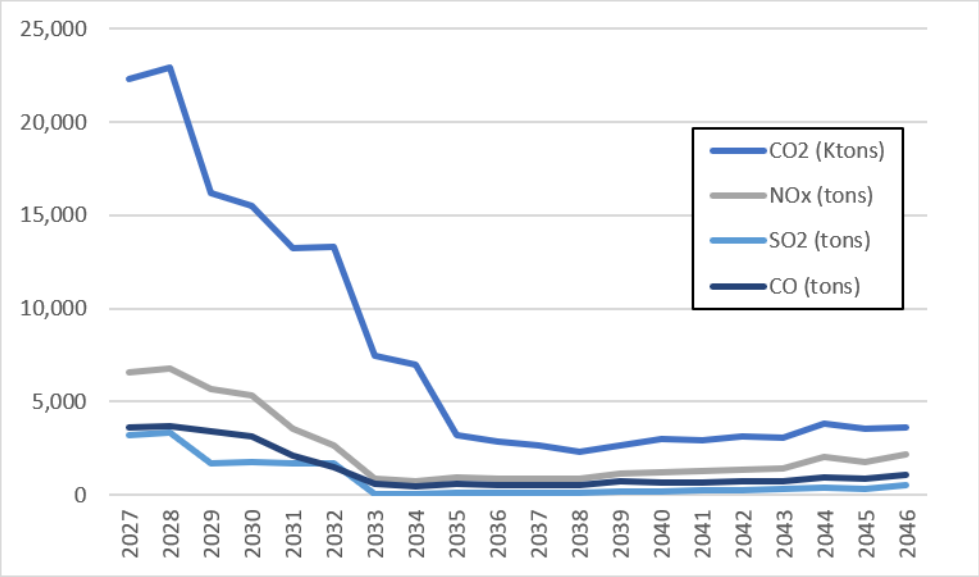
Emissions projections have been made for each of the portfolios presented in this case, including the PCA. Annual emissions projections from the IRP modeling for carbon dioxide (CO_2), carbon monoxide (CO), lead (Pb), mercury (Hg), nitrogen oxides (NOx), particulate matter (PM), sulfur dioxide (SO_2), and volatile organic carbon (VOC) were made on a unit- or facility-level. Details of the emissions and calculations can be found in workpaper BJM-1 and Witness Manning's workpapers. Emissions data from the IRP model outputs were used, where available, to summarize emissions for each of the portfolios in workpaper BJM-1. Also refer to Exhibit A-15 Emissions Projections Summary for emissions data for the four portfolios.

Q45. Can you summarize forecasted emissions based on the PCA run in the BAU scenario?

Line No.

A45. Yes. Based on the retirement of Monroe Power Plant in the PCA, significant reductions in emissions occur in the coinciding years. The PCA results in CO_2 emissions reductions of greater than 60% by 2029 and greater than 80% by 2033 compared to 2005 levels. Detailed emissions data and calculations can be found in Witness Manning's workpapers and workpaper BJM-1. A summary of the trend in emissions can be found in Figures 1 and 2.

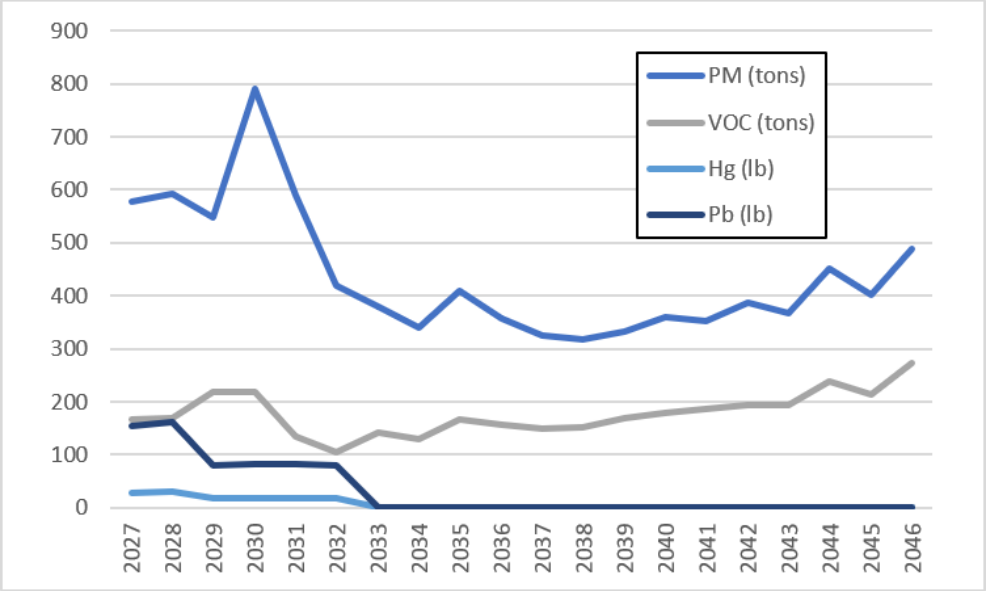
Figure 1 – PCA CO_2, NOx, SO_2, and CO Emissions Trend[1]



[1] Emissions in Figure 1 and Figure 2 are shown for the fleet

Line No.

Figure 2 – PCA PM, VOC, Hg, and Pb Emissions Trend[1]



Q46. What are the major PCA milestones that correspond to the forecasted CO_2 emissions trajectory?

A46. Forecasted CO_2 emissions by resource type are shown in Figure 3. Several major resource milestones reflected in the PCA are reflected in the Company's forecasted CO_2 emissions trajectory:

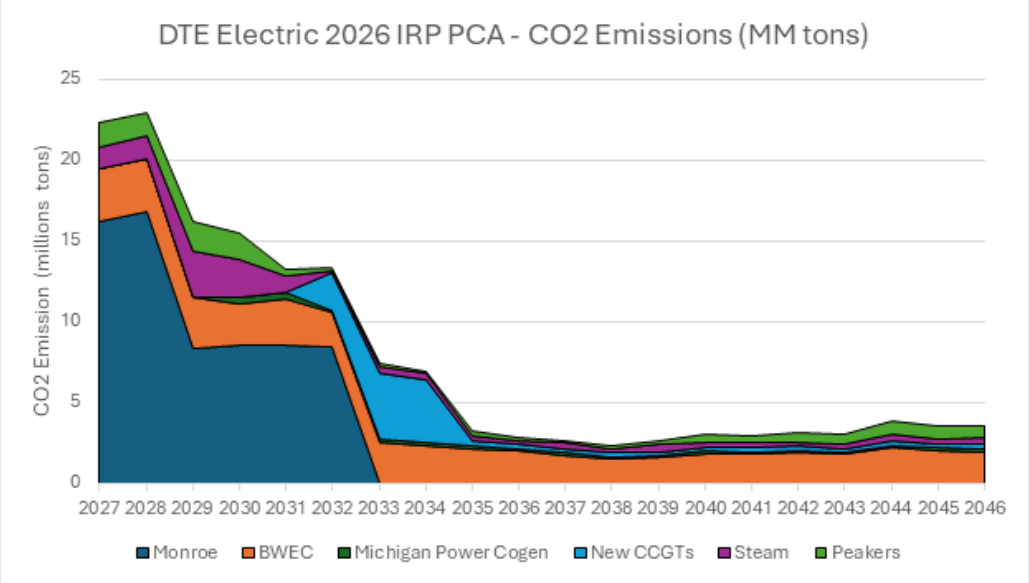
- 2028 – Retirement of Monroe Power Plant Units 3 and 4
- 2032 – Retirement of Monroe Power Plant Units 1 and 2 and the Superior Peaking Station
- 2030-2032 – Addition of approximately 2.2 GW of natural gas cogeneration and CCGT capacity
- 2035 – Installation of CCS at new CCGT facilities

Because the Monroe unit retirements are planned for the end of 2028 and 2032, respectively, the associated reductions in annual emissions are first fully reflected

Line No.

in the following years. Significant reductions in forecasted CO_2 emissions therefore occur in 2029 and 2033 following the phased retirement of Monroe Power Plant. As the Company exits coal, the replacement resource portfolio includes renewables, storage, and combined-cycle natural gas generation that is substantially more efficient and lower-emitting than Monroe Power Plant. Additional CO_2 emissions reductions occur beginning in 2035 with the PCA's modeled CCS implementation.

Figure 3 – Forecasted Annual DTE Electric CO_2 Emissions by Resource Type Under the PCA



Q47. How does the retirement of Monroe Power Plant, retirement of the Superior Peakers, and implementation of the replacement resource portfolio impact forecasted CO_2 emissions?

A47. As the planned coal and peaker retirements occur and the replacement resource portfolio is implemented, including the addition of highly efficient combined-cycle natural gas generation, the Company's forecasted CO_2 emissions decline by approximately 15.5 million tons, from approximately 22.9 million tons in 2028 to approximately 7.5 million tons in 2033. This represents an approximately 68% reduction in forecasted CO_2 emissions prior to the implementation of CCS at the proposed CCGT facilities in 2035.

Q48. What additional effect does the planned installation of CCS at the new CCGT facilities have on forecasted CO_2 emissions?

A48. As discussed above, the PCA reduces annual forecasted CO_2 emissions by approximately 15.5 million tons, or 68%, between 2028 and 2033, prior to CCS implementation at the proposed CCGT facilities in 2035. The PCA assumes that, beginning in 2035, CCS at the proposed CCGT facilities will capture more than 90% of the CO_2 that would otherwise be emitted from those facilities. Figure 3 shows that forecasted annual emissions from the proposed CCGT facilities decline from approximately 4.0 million tons in 2033 to approximately 0.3 million tons in 2035.

Forecasted total Company emissions in 2035 are approximately 3.2 million tons, compared with approximately 7.4 million tons in 2033, an additional system-wide decline of approximately 4.2 million tons. In total, forecasted annual CO_2 emissions are reduced by nearly 20 million tons, approximately 86%, between 2028 and 2035.

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Q49. Why does the largest reduction in annual CO_2 emissions occur between 2028 and 2033, prior to the modeled implementation of CCS in 2035?

A49. The primary driver of the reduction in CO_2 emissions is the retirement of Monroe Power Plant and its replacement with a portfolio of renewables, energy storage, and more efficient natural gas resources. Monroe Power Plant accounts for a substantial majority of the Company's CO_2 emissions in 2028, as shown in Figure 3. Monroe Power Plant's forecasted annual CO_2 emissions are nearly 17 million tons in 2028, accounting for 74% of the Company's forecasted annual CO_2 emissions that year.

Although the retiring Monroe capacity is replaced in part by the proposed CCGT facilities, the proposed CCGTs use modern combined-cycle technology that is substantially more efficient and lower-emitting than the retiring coal-fired generation. In 2033, the new CCGT facilities are expected to emit approximately 4 million tons of CO_2. The forecasted 2033 CO_2 emissions from the new CCGT facilities are nearly 13 million tons less than Monroe Power Plant's forecasted 2028 annual emissions, which is more than 75% of Monroe Power Plant's annual emissions.

The other generation resources included in the Company's resource plan, such as renewables and nuclear, produce no CO_2 emissions. Although the implementation of CCS will further reduce annual CO_2 emissions by approximately 3.7 million tons, the greatest reduction in emissions in the Company's resource plan occurs as Monroe is replaced by CCGTs and a mix of renewables, energy storage, and other natural gas resources prior to the implementation of CCS.

Q50. How does replacing coal-fired generation with combined-cycle natural gas generation substantially reduce CO_2 emissions even without CCS?

A50. Although natural gas-fired generation produces CO_2, modern combined-cycle generating facilities emit substantially less CO_2 per megawatt-hour than coal-fired generating facilities.

Two factors principally account for that difference. First, natural gas contains less carbon per unit of energy than coal. Second, the Company's selected modern combined-cycle technology is substantially more efficient than conventional coal-fired steam generation, meaning less fuel is required to produce the same amount of electricity. The PCA therefore achieves a substantial reduction in CO_2 emissions from the coal-to-gas transition itself, independent of the additional reductions that future CCS can provide.

Q51. Are emissions from the sale and/or purchase of power accounted for in the Company's planning?

A51. Yes. Emissions from purchased power were calculated for the PCA. The Company has projected emissions based on the forecasted amount of power purchased in the future. The calculations were done using emission rates which are similar to the Company's emission rates for future years. Calculations and a summary of the emissions projected from purchased power can be found in workpaper BJM-1.

Q52. There have been several climate change related reports, such as the Intergovernmental Panel on Climate Change (IPCC) reports, released in

recent years. How do the Company's carbon reduction plans align with the results of these studies?

A52. Several reports and studies have been published outlining varying levels of carbon reduction as being required to limit global temperature increases including the Special Reports published by the IPCC. While a specific company's emissions cannot be directly correlated to a level of global temperature increase, DTE Electric's plan to achieve net zero CO2 emissions by 2050 fits within the range of pathways consistent with what is outlined in these reports. The Company is serious about addressing climate change issues regardless of State or Federal plans or regulations. The Company established a plan to transition our generation fleet to low and zero-emitting sources in a manner and timeframe that also continues to ensure reliability and minimizes financial impact on customers. The Company's 2019 IRP planned for CO_2 emissions reductions of 50% by 2030 and 80% by 2040 compared to 2005 levels. The Company subsequently made a commitment to net zero emissions by 2050. The PCA in the 2022 IRP projected CO_2 emissions compared to 2005 levels of 32% by 2023, 65% in 2028, 85% in 2035, 90% by 2040, and net zero CO_2 emissions by 2050. While the specific pathways to net zero are not fully developed at this time, the Company continues to evaluate various technologies to achieve net zero CO_2 emissions. Deploying those technologies in the future, as well as implementing the PCA in this case, will help drive toward the Company's net zero CO_2 emissions goal.

PART III – ENVIRONMENTAL JUSTICE ASSESSMENT

Q53. Can you describe the Company's environmental justice (EJ) analysis purpose and approach?

A53. Yes. The purpose of the EJ analysis is two-fold. First, the EJ analysis evaluates the environmental and health impacts of certain portfolios, thereby informing DTE Electric's modeling and planning process by providing a comparative view of the potential environmental and public health impacts on certain communities under various alternatives studied. Second, the EJ screening and analysis ensure the advisory opinion of EGLE in the utility IRP cases is supported by an environmental and health impact analysis. For each identified portfolio, the Company calculated the emissions from each owned generation facility and MISO electricity purchases for CO_2, NOx, SO_2, CO, PM, VOC, Hg, and Pb; performed an EJ screening and assessment of the potential impacts to vulnerable communities of air emissions, early retirement of fossil-fueled facilities, as well as the impact on water quality, waste disposal, and expected changes in land use for new or retiring resources; and determined health impact estimates for air emissions. Refer to Part II of my testimony for that discussion. Detailed emissions data and calculations can be found in Witness Manning's workpapers and workpaper BJM-1.

Q54. Did the Company perform an Environmental Justice (EJ) screening?

A54. Yes. The Company used EGLE's Michigan Environmental Justice Screening Tool (MiEJScreen) Version 1.5 to perform an EJ screening. All fossil fuel-fired generating facilities were included in the screening. The goal of the screening was to identify EJ Communities, as defined by the IRP Filing Requirements, within a 3-mile radius of each facility. Each facility was mapped and assessed using MiEJScreen. A summary of the MiEJScreen data is included in workpaper BJM-2.

Q55. Were any new generation sources included in the PCA included in the EJ screening?

A55. Yes. The two new generation sources proposed in the PCA were assessed based on the currently expected locations. Neither source was found to be within a 3-mile radius of an EJ community using MiEJScreen at this time.

Q56. What were the results of the EJ screening?

A56. MiEJScreen was used to identify facilities which were at or above the 75th percentile for the overall composite index or either of the Low-Income Population or Black, Indigenous, People of Color (BIPOC) population layers. Using MiEJScreen, seven of the Company's facilities were identified as being within a 3-mile radius of a community identified by the EJ screening. The facilities with at least one MiEJScreen indicator at or above the 75th percentile as well as a summary of the indicators for these facilities are included in Table 2 below.

Table 2 – Environmental Index Summary for Facilities within a 3-Mile Radius of Communities Identified by the EJ Screening

Facility	Overall Percentile	Low Income Percentile	BIPOC Percentile
Dearborn Energy Center	98	97	92
Delray Peakers	100	99	97
Hancock Peakers	67	47	87
Monroe Power Plant	89	97	73
Northeast Peakers	100	100	99
Superior Peakers	94	98	87
Wilmot Peakers	85	92	84

Q57. How does the Company's PCA impact the areas associated with the EJ analysis that was performed?

A57. While the MiEJScreen is a screening tool to identify environmental index values for a given area, it is not a method to compare portfolios or to assess the impact on EJ communities of the PCA. Beyond the MiEJScreen data analysis, the various portfolios can be qualitatively assessed to compare the impacts of the portfolios to each other and the impact of the PCA more broadly. For example, the ongoing conversion of Belle River Power Plant to natural gas decreases or eliminates emissions, water use, water discharge, and ash generation. Similarly, the planned retirement of Monroe Power Plant will eliminate the emissions, water use, water discharge, and ash generation from that facility. The planned new generation will be much lower emitting and use much less water than the current power plants and the reduction in overall emissions and water use will have a positive impact on air and water quality throughout the area. From an environmental perspective, the four portfolios in this case are essentially the same and provide the same impact to EJ communities and the area as a whole.

As stated previously, the PCA in this case provides for significant emissions reductions. The PCA will also result in reductions in water intake and discharge, as well as waste generation and disposal, including ash. Overall water use will be reduced significantly by the generation plan outlined in the PCA. The natural gas conversion and future operation at Belle River Power Plant will reduce water used for electric generation at the plant by 60%. Water use at Monroe will decrease by 50% with the retirement of the first two units and will be eliminated with the retirements of the remaining two units. These reductions in water use will also

Line No.

decrease the water discharge from the facilities, including thermal discharge reductions.

The proposed new generation projects in Monroe and Livingston County are designed to use air-cooled condenser systems for steam cycle cooling and will use over 90% less water than similarly sized plants with once-through cooling such as Belle River and Monroe Power Plants. The new projects are also being developed as CCS-ready facilities to accommodate the Company's planned future use of CCS to support compliance with Michigan's Clean Energy Standard.

Waste generated at Belle River and Monroe Power Plants will also decrease significantly with the conversion of Belle River to natural gas and retirement of Monroe Power Plant. This includes bottom ash, fly ash, and other waste reductions. The generation of bottom ash and fly ash will be eliminated at Belle River Power Plant once the conversion to natural gas is complete. Bottom ash and fly ash generation will decrease by 50% with the retirement of the first two units of Monroe Power Plant and will be eliminated with the retirements of the remaining two units. The Company has no other units that generate ash. The reductions in ash generation will have a corresponding reduction in the amount of ash sent to landfill.

It is important to note that five of the sites identified as having an environmental index at or above the 75th percentile are peaker sites. As outlined in Witness Pratt's testimony, the Company performed a peaker analysis which was considered in the Company's IRP modeling and the PCA in this case. One outcome of that study is the retirement of the Superior Peakers in 2032. Additionally, since the Company's

previous IRP, the Company retired Northeast 11-1 peaker, the Slocum peakers, the River Rouge peakers, and the St. Clair 12 diesel peakers and suspended operation of Fermi Units 11-3 and 11-4. Northeast and River Rouge were located in EJ areas.

PART IV – IMPACT ASSESSMENT

Q58. Did the Company perform a health impact assessment?

A58. Yes. The Company used the EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) Desktop Edition 5.0 to determine the health impact estimates for the air emissions reductions in the PCA in this case. COBRA can be used to explore how changes in air pollution can affect human health and estimate the economic impact that impact on human health may have.

COBRA was used to assess the overall fleet-wide health impacts and associated costs for all portfolios. Impacts and associated costs were analyzed to the county-level, the most refined level that can be assessed using COBRA. The impacts were also assessed at the state-level. The COBRA model requires some defined inputs: state, sector, and emissions information. A county input is optional in the COBRA model. The sector was chosen as "Fuel Combustion: Electric Utility". The model has entry fields for emissions data for $PM_{2.5}$, SO_2, NO_x, and VOC. For this assessment, emissions projections for 2027 and 2046 were used to evaluate the impacts. The COBRA model output provides projections for all counties and state-wide. A summary can be found in workpaper BJM-3.

Q59. What were the results of the health impact assessment performed using the COBRA model?

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A59. The COBRA model summarizes impacts for change in incidence (cases, annual) and monetary value (dollars, annual). A low and high value is provided for some categories. The assessment of health impacts using the COBRA tool showed an overall benefit for the PCA. A summary of some results of the health impact assessment using the COBRA model based on the PCA is provided in Table 3 below. Further detail on the data from the assessment for other portfolios and county-level data can be found in workpaper BJM-3. The low value is used in the table for those endpoints for which low and high values are provided by the COBRA model.

Table 3 – Summary of COBRA Health Impact Assessment – State Level

Health Endpoint	Change in Incidence (Reduction)	Monetary Value
Mortality	16.00	$252,264,616
Total Asthma Symptoms	9,489	$2,368,579
Total Incidence, Asthma	55.11	$4,604,323
Total ER Visits, Respiratory	21.85	39,189
Total Health Benefits		$268,377,277

There is some important information provided in the COBRA tool from EPA to help understand the results:

In the results table, positive numbers indicate annual reductions in the number of cases and the associated costs avoided. Incidence refers to the number of new cases of a health endpoint over a specified period of time. The change in incidence is not

necessarily a whole number because COBRA calculates statistical risk reductions which are then aggregated over the population. For example, if 150,000 people experience a 0.001% reduction in mortality risk, this would be reported as 1.5 "statistical lives saved." This statistical life, and its associated monetary value, represents the sum of many small risk reductions and does not correspond to the loss or value of an individual life. COBRA calculates the monetary value of each health endpoint based on data on the healthcare costs of the health endpoint and research into the willingness to pay to avoid the health endpoint.

Q60. Can you describe the PM2.5 impact assessment performed by the Company and the results based on the PCA?

A60. Yes. As can be seen in the emissions projections provided in Witness Manning's workpapers and workpaper BJM-1, there is a decrease in PM emissions over the course of the PCA. As such, the impacts of PM2.5 will also decrease over time, including within the communities previously identified in the EJ screening as well as areas near facilities identified as having an EJ environmental index above the 75th percentile that were previously identified. The emissions reductions proposed by the PCA, including the reductions in PM2.5, will reduce impacts near the emitting facilities as well as the downwind impacts of PM2.5 and other pollutants.

Q61. Can you describe the impact assessment on NAAQS non-attainment areas performed by the Company and the results based on the PCA?

A61. Yes. The Company assessed the impact of the PCA on non-attainment areas where its resources are located. This assessment included current non-attainment areas and any areas that could be designated as non-attainment based on current

reasonably known information. The assessment considered all criteria pollutants for which an area could be designated as non-attainment as well as precursors to those pollutants. Although this assessment was completed based on the Company's emissions projections, it is important to note that non-attainment areas can be impacted by emissions from many other sources.

The Company's PCA provides further reductions in emissions over the course of the PCA. While the current seven-county ozone nonattainment area in southeast Michigan is impacted by industries and factors beyond the Company, the emission reductions projected by the PCA in this case will provide benefit to the status of the area related to ozone NAAQS by providing further emissions reductions. While the Company cannot predict at this time whether additional areas within the operating area will be designated as nonattainment in the future due to monitored ambient air concentration changes or changes in regulation, the Company believes that the emissions reductions included in the PCA in this case will nonetheless allow for further improvement in the area's air quality.

PART V – CON FILING

Q62. Does your analysis distinguish between environmental information associated with the proposed Livingston County and Monroe County projects and environmental information associated with the broader PCA?

A62. Yes. Where the available information permits, my testimony identifies environmental considerations associated with the construction and operation of the proposed projects and separately presents projected emissions and other environmental information for the broader PCA. This distinction allows the

Commission to consider the anticipated effects of the individual projects while also understanding how the projects are expected to operate within the Company's planned generation portfolio. I have not attributed a portfolio-level effect to an individual project where the available information supports only a portfolio-level conclusion.

Q63. Can you describe the environmental considerations associated with the Company's CON filing?

A63. Yes. In addition to many of the regulations discussed above which were reviewed for the PCA, the proposed new generation sources included in the PCA were evaluated from an environmental standpoint. There are certain environmental regulations that are applicable to the proposed projects due to the nature of the projects and their operations.

Q64. What environmental regulations govern the operation of a natural gas-fired combined-cycle power plant?

A64. Many regulations govern the operation of natural gas-fired combined-cycle power plants. This includes some of the regulations covering other power plants, such as NPDES regulations. There are several regulations which specifically impact the proposed new generation sources including, but not limited to the following:

- NSPS KKKKa
- NESHAP
- TTTTa/UUUUa

Q65. Has the Company planned for compliance with these regulations for the proposed projects?

A65. Yes. All installed equipment associated with any new generation sources will be permitted to comply with all applicable regulations. Most importantly, the proposed projects are being installed with the most current generation and emissions control technologies. These emission controls meet requirements for best available control technology (BACT) and lowest achievable emission rate (LAER) including selective catalytic reduction (SCR) and oxidations catalyst which will greatly reduce uncontrolled emissions. SCR will reduce NOx emissions by approximately 90% and the oxidation catalyst will reduce emissions of carbon monoxide (CO) and other hazardous air pollutants (HAPs) by approximately 90%.

Q66. What are the Company's plans for obtaining air and other permits for the proposed projects?

A66. The Company currently plans to file an air permit application for the first project in Livingston County with EGLE shortly after filing this IRP. Several other environmental permits will be required for construction and operation of the new plants. All permits will be applied for, as appropriate, to ensure that the necessary permits are in place and do not impact the project construction and/or operational timeline. Permits will be obtained similarly for the Monroe County project in the future depending on the timing of the project.

Q67. What is the relationship between the environmental information presented in your testimony and the subsequent environmental permitting processes for the proposed projects?

A67. My testimony identifies the environmental requirements, anticipated project effects, compliance measures, and permitting considerations that can reasonably be evaluated based on the current project designs and information available at this stage. The Company will separately apply for and obtain the applicable environmental permits and other approvals required before undertaking regulated construction and operational activities. EGLE and other permitting authorities will determine the final permit-specific technical requirements, emission or discharge limits, monitoring provisions, and other enforceable conditions through the appropriate permitting processes based on the applicable laws and regulations. Where an environmental effect or requirement depends on final engineering, a permit application, agency review, or future operating conditions, my testimony identifies the information presently available without assuming the outcome of that later review.

Q68. Can you describe the emissions profile of the proposed projects and compare them to emissions from Monroe Power Plant, which the Company plans to retire?

A68. Yes. Emissions from the proposed projects will be much lower. The new generation sources proposed in the PCA are fired by natural gas, have current technology for operation, and include emissions controls which qualify as BACT. The overall emissions from the PCA, including the new generation resources are summarized in the emissions analysis in my testimony above.

Q69. Does this complete your testimony?

A69. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

PUBLIC DIRECT TESTIMONY OF

HARRY O. STANSELL JR.

DTE ELECTRIC COMPANY QUALIFICATIONS AND DIRECT TESTIMONY OF HARRY O. STANSELL JR.

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Q1. What is your name, business address and by whom you are employed?

A1. My name is Harry O. Stansell Jr. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from the University of Michigan – Dearborn in 2002 with dual Bachelor of Science degrees in Electrical Engineering and Computer Engineering. In 2010, I received a Master of Business Administration from the University of Michigan Ross School of Business.

Q4. What is your professional experience?

A4. After graduating from the University of Michigan – Dearborn, I joined Yazaki North America as an engineer within the Trans-Pacific Nikkei Operations business unit. Throughout my career at Yazaki, I was responsible for the design, development and testing of electrical distribution systems for several Nissan and Infiniti vehicle platforms.

In 2012, I joined DTE Energy as a Financial Consultant in the Advanced Degree Development Program, where I completed rotations in the Renewable Energy group, DTE Gas Decision Support, and the Budgeting, Forecasting, and Reporting group. Upon completion of the program, I was promoted to Manager of Business

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Development within the Renewable Energy group, where I was responsible for planning and executing renewable energy activities for the Company.

In February 2017, I transitioned to the Fossil Generation group to support development activities associated with the Company's 2017 Certificate of Necessity (CON) filing. In this role, I led the implementation of a generation request for proposals (RFP) process to support a build versus buy analysis for a baseload combined cycle gas turbine (CCGT) facility and supported multiple witnesses in the CON proceeding that resulted in approval of the Blue Water Energy Center. Following this assignment, I was named Manager of the newly formed Fossil Generation Strategy group, where I supported strategic analysis and activities related to the safe operation of the Company's generation fleet and retirement of the Company's aging coal fleet.

In July 2021, I was appointed Manager of the Enterprise Risk Management group, where I led efforts to identify and manage the Company's top risks, coordinated the annual enterprise risk assessment process, and supported the Risk Management Committee.

In April 2024, I was promoted to my current role as Director, Generation Development, where I am responsible for advancing development of new non-renewable generation resources for the Company.

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Q5. What are your current duties and responsibilities?

A5. In my current role as Director, Generation Development, I am responsible for the early-stage development of non-renewable generation resources for the Company. This includes advancing projects intended to replace the planned retirement of the Monroe Power Plant and to serve incremental load growth within the Company's service territory. My responsibilities include overseeing project development activities related to site evaluation, technology and design development, project cost development, and other activities necessary to advance proposed generation resources toward construction and operation.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I sponsored testimony in the following MPSC cases:

U-17793 DTE Electric's 2015 Amended Renewable Energy Plan

U-17804 DTE Electric's 2014 Renewable Energy Plan Reconciliation

U-18111 DTE Electric's 2016 Amended Renewable Energy Plan

In addition, I have submitted affidavits supporting approval of renewable energy contracts (Case Nos. U-17793-PWP and U-17793-Solar) and supporting the Company's proposed Voluntary Renewable Energy Pilot Program (Case No. U-18076) before the MPSC.

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support DTE Electric's requests for CONs associated with two new carbon capture and storage-ready (CCS-ready) natural gas fueled CCGT generation facilities included in the Company's 2026 Integrated Resource Plan (IRP) Proposed Course of Action (PCA): the Livingston County project and the Monroe County project (Projects). My testimony focuses on the early-stage development activities undertaken to define, evaluate, and mature the proposed projects. Specifically, my direct testimony:

- Describes the proposed Projects' locations, selected technology, generating capacity, expected commercial operation dates, and certain operational characteristics;
- Explains the basis for the selected generation technology, configuration, and other key facility design features;
- Describes the development and basis of the Company's capital cost estimates and explains why those estimates are reasonable at the current stage of project development;
- Supports the proposed operations and maintenance (O&M) plans and associated cost assumptions;
- Describes the prudent CCS-ready design features incorporated into the Projects and the development work supporting the Company's planned future implementation of CCS;
- Describes the Company's current expectations regarding the timing and implementation pathway of future CCS;

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- Supports the determination that the Projects are the most reasonable and prudent means of meeting the Company's needs.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-16	NDA Livingston County Project EPC Capital Cost Estimate
A-16.1	NDA Monroe County Project EPC Capital Cost Estimate
A-16.2	NDA Carbon Capture Pre-FEED Study
A-16.3	NDA Carbon Capture Balance of Plant Cost Estimate

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

Q10. How is your testimony organized?

A10. My testimony consists of the following seven (7) parts:

Part I	Overview of Proposed Projects
Part II	Site Selection and Site Control
Part III	Technology Selection, Configuration, and Operating Characteristics
Part IV	Capital Cost Estimates and Cost Approval Support
Part V	Operations, Maintenance, and Operating Cost Estimates
Part VI	Planned Implementation of CCS
Part VII	Support for CON Determinations and Conclusion

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Part I: Overview of Proposed Projects

Q11. Can you identify the Projects addressed in your testimony?

A11. Yes. My testimony addresses two proposed Company-owned, CCS-ready CCGT facilities: the Livingston County project, with an approximate nominal capacity of 1,400 MW, and the Monroe County project, with an approximate nominal capacity of 700 MW. These facilities will provide firm, dispatchable capacity and energy needed to serve the Company's customers and support the Company's evolving resource portfolio and future system needs, as described in detail by Witness Pratt and Witness Manning. The Projects are being developed as CCS-ready facilities to accommodate the Company's planned future implementation of CCS to support compliance with Michigan's Clean Energy Standard.

Q12. What does it mean that the Livingston County project and Monroe County project are being developed as CCS-ready facilities?

A12. A CCS-ready facility is one that is intentionally designed to accommodate the future installation and operation of CCS equipment. For the Livingston County and Monroe County Projects, the Company incorporated CCS considerations into site selection, land acquisition, facility layout, utility routing, and overall project development activities.

These considerations include reserving sufficient space for future carbon capture equipment, carbon dioxide compression facilities, and associated infrastructure required to support future CCS implementation.

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Additionally, the heat recovery steam generator (HRSG) design incorporates provisions for future connection of a carbon capture system, including a flanged breech with a blank plate for the future connection to the CCS duct. This is intended to reduce the extent of future modifications and outage work required to connect the CCS ductwork. By incorporating these considerations during project development, the Company can reduce the potential need for future site redesigns, facility modifications, and associated costs when CCS is implemented.

These design considerations help ensure that the facilities can accommodate future carbon capture equipment designed to achieve a carbon dioxide capture rate greater than 90%. Witness Hajj addresses the applicable Clean Energy Standard requirements of MCL 460.1003(i)(ii) and the role of CCS in the Company's compliance plan.

Q13. What is the expected commercial operation date of the Livingston County project?

A13. The Livingston County project is expected to achieve commercial operation by the end of 2031. Witness Banks provides further details regarding the Livingston County project schedule.

Q14. What is the expected commercial operation date of the Monroe County project?

A14. The Monroe County project is expected to achieve commercial operation by the end of 2032. Witness Banks provides further detail regarding the Monroe County project schedule.

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Part II: Site Selection and Site Control

Q15. **What considerations informed the Company's evaluation and selection of the proposed sites for the Projects?**

A15. In evaluating the proposed Project sites, the Company considered factors relevant to the feasibility and timely development of large combined-cycle generating facilities. These considerations included land availability and site control, existing zoning, constructability, access to natural gas and electric transmission infrastructure, location within Southeast Michigan to support system reliability as Monroe Power Plant retires, permitting considerations, and the ability to accommodate the proposed facility configuration, future CCS infrastructure, and a feasible path to geologic carbon storage. These considerations informed the Company's selection and continued development of the proposed Livingston County and Monroe County Projects.

Q16. Why was proximity to interstate natural gas pipelines infrastructure an important site selection consideration?

A16. Large-scale combined-cycle generating facilities require access to substantial quantities of natural gas. Accordingly, access to interstate natural gas pipeline infrastructure was an important site selection consideration.

Sites located without a pathway for direct access to interstate natural gas pipeline infrastructure may require more extensive new pipeline facilities, which can increase project costs and introduce additional engineering, routing, permitting, environmental, development, and schedule considerations. For these reasons, the Company considered pipeline access together with other siting factors, including

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access to 345-kV transmission infrastructure, suitable site conditions, compatible zoning, and sufficient land availability to support both the generating facilities and future CCS-related infrastructure of the proposed Projects.

Q17. Did the Company consider whether other Company-owned generation sites in Southeastern Michigan could support the siting of the proposed facilities?

A17. Yes. The Company considered whether other DTE Electric generation sites in Southeastern Michigan could satisfy the development requirements of the proposed Projects. While existing generation sites may offer certain advantages, such as existing electric infrastructure and suitable preexisting zoning classification, no existing sites were close in proximity to interstate natural gas pipeline infrastructure, which the Company considered a critical siting requirement.

Providing adequate natural gas supply to a large combined-cycle generating facility at such locations would require significant new pipeline infrastructure, which would increase project costs and introduce additional routing, permitting, environmental, and schedule considerations. The Livingston County and Monroe County project sites provide access to both interstate natural gas pipeline infrastructure and 345-kV transmission facilities while also providing sufficient acreage and compatible site conditions for the proposed facilities and future CCS-related infrastructure. Based on these factors, the Company concluded that the selected sites were better suited to support the development of the proposed Projects.

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Q18. What is the current status of site control and current use of the proposed project sites?

A18. The Company currently holds land option agreements for both project sites. These land options agreements provide the Company with contractual site control while the Projects continue through the community engagement, development, and approval processes. The Company intends to exercise those options following receipt of the necessary approvals, including the requested CONs and applicable local site plan approvals.

The sites for the Projects are within zoning classifications that permit the development of power generation facilities, supporting the feasibility of project development. I discuss the site-specific zoning and development characteristics of each of the Projects below.

Q19. Please describe the location of the Livingston County project and the site characteristics that support its development.

A19. The Livingston County project is planned for Handy Township, Livingston County, Michigan. This site has several characteristics that support development of the proposed project.

First, the site is located within an area that is zoned as Research and Development and permits development of power generation facilities, which supports an efficient local approval process.

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Second, the site is located at the intersection of the Vector and Rover interstate natural gas pipelines, which provides access to existing interstate natural gas infrastructure while minimizing the need for new pipeline lateral infrastructure.

Third, the site is directly adjacent to the Blackfoot-to-Madrid 345-kV transmission lines, limiting the extent of generation tie-line infrastructure required to interconnect the project.

Finally, the site provides sufficient land area to accommodate the proposed CCGT facility and future carbon capture infrastructure, supporting the Company's objective to develop the facility as CCS-ready to preserve the option of integrating CCS in the future, consistent with longer-term planning considerations.

Together, these characteristics support the site's suitability and timely development for the proposed Livingston County project. Figure 1 illustrates the proposed Livingston County project site, including nearby electric transmission lines and access to existing interstate natural gas pipelines.

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Figure 1 Proposed Livingston County CCS-Ready CCGT Site



Q20. Please describe the location of the Monroe County project and the site characteristics that support its development.

A20. The Monroe County project is planned for Milan Township, Monroe County, Michigan. This site also has several characteristics that support development of the proposed facility.

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First, the site is located within an area zoned for industrial use, which permits development of power generation facilities, thereby supporting an efficient local approval process.

Second, the site is located approximately five miles from the NEXUS and ANR interstate natural gas pipelines, which provides access to existing interstate natural gas infrastructure while minimizing the need for new pipeline lateral infrastructure.

Third, the site is located approximately two miles from the Milan-to-Monroe 345-kV transmission lines, limiting the extent of generation tie-line infrastructure required to interconnect the project.

Finally, the site provides sufficient land area to accommodate the proposed CCGT facility and future carbon capture infrastructure, supporting the Company's objective to develop the facility as CCS-ready to preserve the option of integrating CCS in the future, consistent with longer-term planning considerations.

Together, these characteristics support the site's suitability and development for the proposed Monroe County project. Figure 2 illustrates the proposed Monroe County project site, including nearby electric transmission lines and access to existing interstate natural gas pipelines.

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Figure 2 Proposed Monroe County CCS-Ready CCGT Site



Part III: Technology Selection, Configuration, and Operating Characteristics

Q21. What combined-cycle configuration is being proposed for each project?

A21. The Projects are designed as single-shaft 1x1 combined-cycle trains, with each 1x1 train consisting of a natural gas-fired combustion turbine, HRSG, steam turbine, and electrical generator operating as an integrated unit with the combustion turbine and steam turbine connected to a common generator shaft.

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The Livingston County project is designed as a two-unit configuration, consisting of two 1x1 single-shaft combined-cycle trains, providing a nominal capacity rating of approximately 1,400 MW.

The Monroe County facility is designed as a single-unit configuration, consisting of one 1x1 single-shaft combined-cycle train, providing a nominal capacity rating of approximately 700 MW.

Q22. Can you describe how the components of a combined-cycle generating facility work together to produce electricity?

A22. A combined-cycle generating facility generates electricity in two steps instead of one. First, natural gas is combusted in a combustion turbine, which drives a generator and produces electricity. This combustion process produces a significant amount of heat. Rather than allowing that heat to be wasted, it is captured by a HRSG, which uses the heat to produce steam. The steam is then directed to a steam turbine, which drives a second generator and produces additional electricity. By generating electricity from both the combustion turbine and the steam turbine, a combined-cycle facility is able to produce significantly more electricity from the same amount of fuel than a simple-cycle generating unit.

Q23. Why did the Company select a 1x1 single-shaft configuration for the Projects?

A23. The Company selected a 1x1 single-shaft combined-cycle configuration based on its ability to balance efficiency, reliability, cost, and operational flexibility for the proposed facilities.

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In a single-shaft configuration, the combustion turbine, steam turbine, and generator are connected along a single shaft and operate as an integrated unit. This differs from a multi-shaft configuration, where the combustion turbine(s) and steam turbine each drive separate generators.

The single-shaft configuration reduces the number of major components, generators, electrical systems, and associated auxiliary equipment relative to a comparable multi-shaft configuration. This supports a smaller facility footprint and reduces the amount of needed equipment, capital, and maintenance requirements while providing improved efficiency and operating performance required for the Projects.

Additionally, the 1x1 single-shaft configuration offers a scalable and repeatable design approach that can be deployed across a range of potential project sizes. With each 1x1 unit operating independently at approximately 700 MW, the configuration serves as a standardized building block that can be replicated to meet varying capacity requirements while maintaining consistency in equipment configuration, plant design, operation and maintenance, spare parts requirements, training programs, and engineering standards. This standardization supports operational efficiencies, simplifies maintenance and operations, and can improve project execution and long-term fleet management.

Based on these considerations, the Company determined that the 1x1 single-shaft configuration represents the most reasonable and prudent technical design for the proposed facilities.

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Q24. What factors were considered in selecting the combustion turbine technology for the proposed Projects?

A24. In selecting the combustion turbine technology for the proposed Projects, the Company focused on latest-generation advanced-class combustion turbine technology, including the GE 7HA.03, Mitsubishi M501JAC, and Siemens HL-class turbines, rather than earlier-generation equipment such as F-class units or prior-generation advanced-class turbines.

The Company considered the thermal efficiency, operating characteristics, reliability and commercial experience of the available technologies, as well as the resulting implications for fuel consumption and operating cost savings over the life of the facility.

Latest-generation advanced-class combustion turbines provide high thermal efficiency, which reduces the amount of natural gas required to produce electricity, together with the operating characteristics that include strong ramping capability and flexible operation across a range of load conditions.

In addition, these machines are supported by commercial deployment at scale and vendor experience, providing an established basis for evaluating their reliability and long-term performance.

Based on these considerations, the Company determined that latest-generation advanced-class combustion turbine technology was appropriate for the proposed Projects and proceeded with a competitive procurement process for the associated

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power island equipment (PIE), which includes the combustion turbines, steam turbines, generators, HRSGs, control systems, and auxiliary equipment that collectively comprise the generating equipment for the combined cycle facility.

Q25. How does the selected configuration and combustion turbine technology support operational flexibility?

A25. The selected configuration supports operational flexibility by enabling the proposed Projects to respond to changing system conditions and operational requirements.

The 1x1 single-shaft configuration allows each unit to be started, operated, and maintained independently, providing flexibility in dispatching the Projects and scheduling maintenance and outages. This capability is particularly important for the Livingston County project, where the two 1x1 trains can be operated separately to support system needs.

In addition, the use of advanced-class combustion turbine technology provides strong operational performance, including efficient startup, ramping capability, and the ability to operate over a wide range of load conditions. These characteristics allow the facilities to respond to fluctuations in demand and complement other generation resources on the system.

Together, the selected configuration and technology provide a high degree of operational flexibility, supporting reliable and efficient operation of the proposed facilities over their expected life.

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Q26. Did the Company conduct a competitive procurement process for the combustion turbines and associated PIE?

A26. Yes. The Company conducted a competitive procurement process for advanced-class combustion turbines and associated PIE. Through this process, the Company selected the GE 7HA.03 combustion turbine and associated PIE, based on its high efficiency, strong operational performance, and commercial maturity. Witness Banks provides additional detail regarding the procurement process and project execution strategy for both Projects. Based on these considerations, the Company determined that the GE 7HA.03 and associated PIE represents a reasonable and prudent choice for the proposed facilities, which support the technical basis for the CCGT configurations and performance assumptions for the Projects I discuss throughout my testimony.

Q27. Are there any additional attributes of the selected combustion turbine technology that may provide future flexibility?

A27. Yes. Although the proposed facilities are designed to operate on natural gas, the selected GE 7HA.03 combustion turbine utilizes a combustion system that has been validated to operate on hydrogen-natural gas fuel blends containing up to 50 percent hydrogen by volume. This capability is not part of the proposed project scope and was not a basis for selecting the technology. However, it may provide additional flexibility in the future should hydrogen production, transportation infrastructure, and market conditions evolve in a manner that makes hydrogen use practical and economical.

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Q28. What are the expected performance characteristics of the proposed facilities?

A28. The proposed Projects are expected to achieve performance characteristics consistent with modern advanced combined-cycle generation, including high thermal efficiency and flexible operating capability.

Based on the selected advanced-class combustion turbine technology, the Projects are expected to operate at a nominal net heat rate of 6,500 Btu/kWh, with an expected range of approximately 6,200 to 6,600 Btu/kWh at full fired load across different seasonal conditions. This represents a meaningful improvement compared to earlier-generation combined-cycle technologies, such as F-class units, which typically operate at higher heat rates and therefore require more fuel per unit of electricity produced.

The improved efficiency of the selected technology directly reduces fuel consumption and lowers emissions intensity on a per-megawatt-hour basis, supporting both cost-effective operation and environmental performance.

In addition to efficiency, the selected equipment provides relatively rapid startup, strong ramping capability, and operation across a wide load range, as discussed above.

These characteristics provide the technical basis for the efficiency and operational flexibility expected from the proposed Projects.

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Q29. What is the expected operating life of the proposed facilities?

A29. The Company has assumed an expected operating life of approximately 30 years for both the Livingston County project and Monroe County project. This assumption is consistent with the design basis developed for the Projects and the expectations communicated to equipment suppliers during the procurement process. Specifically, the PIE was specified to support a 30-year design life, with continuous operational availability over that period subject to routine inspections, maintenance, repairs, and replacement of major components as necessary. This expectation is consistent with modern combined-cycle generating facilities and the anticipated operating profile of the proposed projects.

The Company's O&M and major maintenance planning, which I discuss later in my testimony, likewise reflects operation of the Projects over this expected life.

Q30. What environmental control technologies will be incorporated?

A30. The selected technology and design approach support strong environmental performance through a combination of high efficiency, advanced combustion system design, and emissions control technologies.

The proposed Projects incorporate several design features and control technologies related to air emissions. As discussed previously, the selected advanced-class combustion turbine technology provides high generating efficiency and incorporates an advanced combustion system. In addition, the Projects' designs include post-combustion environmental control equipment, including selective catalytic reduction (SCR) for the control of nitrogen oxides (NOx) and oxidation

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catalysts for the control of carbon monoxide (CO). The selected advanced-class combustion turbine technology also supports improved emissions performance compared to earlier-generation equipment through both higher efficiency and advanced combustion system design.

Taken together, these characteristics support a generation design that is efficient, environmentally responsible, and adaptable to future requirements.

Q31. Do the Projects comply with all state and federal environmental requirements?

A31. Yes. Witness Marietta provides additional testimony regarding the applicable environmental regulations, compliance requirements, and projected emissions.

Q32. What cooling technology will be used for the proposed Projects, and why was it selected?

A32. The proposed Projects are designed to use air-cooled condenser systems for steam cycle cooling. The Company selected air-cooled technology based on its ability to significantly reduce water consumption compared to wet-cooled systems. This is an important consideration for the proposed project locations, which are not situated adjacent to large bodies of water that would readily support more water-intensive cooling approaches. Air-cooled systems reduce the need for large volumes of cooling water withdrawal and discharge, making the technology better suited to the characteristics of the proposed sites.

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Part IV: Capital Cost Estimates and Cost Approval Support

Q33. What is the scope of the capital cost estimates you support in your testimony?

A33. The capital cost estimates I support reflect the costs to develop and construct the proposed CCS-ready Livingston County and Monroe County CCGT projects, as currently designed, including the CCS-ready design features presently incorporated into the Projects.

The estimates do not include the future cost of CCS equipment, carbon dioxide transportation and storage infrastructure, or other costs associated with future CCS implementation. Those future CCS implementation costs are not part of the capital cost approval requested for the Projects in this proceeding and would be subject to future Commission review and approval.

The capital cost estimates also exclude separately determined Midcontinent Independent System Operator (MISO) transmission network upgrade costs and financing costs, including Allowance for Funds Used During Construction (AFUDC). Witness Djordjevic addresses transmission-related costs, while Witness Uzenski addresses the financing plan and the treatment of AFUDC.

Q34. What is the estimated capital cost for the Livingston County project?

A34. The estimated capital cost for the Livingston County project is approximately $3.925 billion, excluding financing costs. The estimated capital cost is summarized in Table 1.

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Table 1 CCS-Ready CCGT Cost Estimate for the 1,400 MW Livingston County Project (Millions)

Cost Category	Cost
Engineering, Procurement and Construction (EPC) Scope	[redacted]
Owner's Costs	
Contingency	
Total Capital Cost	**$3,925**

The estimated capital cost consists of three principal categories: (1) EPC Scope; (2) Owner's Costs; and (3) Contingency.

The EPC Scope category includes the engineering, construction labor, balance-of-plant systems, materials, and other costs necessary to construct and place the facility into service.

Owner's Costs include the PIE, major electrical equipment, project development, permitting, owner's engineering, project management, Company labor, land acquisition, and other costs incurred directly by the Company to support project development and execution. As discussed by Witness Banks, procurement activities have been completed for major equipment scopes, including the PIE, generator step-up transformers, unit auxiliary transformers, and high-voltage breakers.

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Contingency represents funding included in addressing identified project risks and remaining uncertainties associated with the Project at its current stage of development. Witness Banks provides testimony regarding the Company's approach to identifying, evaluating, and quantifying project risks and the resulting contingency included in the project estimate.

Q35. How was the capital cost estimate for the Livingston County project developed?

A35. The capital cost estimate for the Livingston County project was developed using a combination of project-specific engineering, completed procurement activities, vendor quotations, and industry-standard cost estimating practices.

To develop the EPC scope portion of the estimate, the Company's Owner's Engineer, Burns & McDonnell, prepared a project-specific Class 4 cost estimate for the proposed facility. Burns & McDonnell developed the estimate assuming an EPC execution approach utilizing multiple subcontractors under an open-book commercial structure, which Burns & McDonnell identified as consistent with current market conditions. This contracting methodology is consistent with the approach selected for the Livingston County Project as described by Witness Banks.

As part of this effort, Burns & McDonnell developed key project-specific engineering deliverables, including a civil grading and drainage plan, piping and instrumentation diagrams, a single-line electrical drawing, conceptual architectural layouts, utility routing studies, and project-specific quantity takeoffs to support the

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estimate. Burns & McDonnell also obtained budgetary quotations for third-party equipment and materials and reviewed third-party labor studies to inform construction cost assumptions. Additional details regarding the EPC scope cost estimate are provided in Confidential Exhibit A-16, NDA Livingston County Project EPC Capital Cost Estimate.

In addition, the Company completed competitive procurement activities for major equipment scopes, including the PIE, generator step-up transformers, unit auxiliary transformers, and high-voltage breakers. Pricing obtained through those procurement activities was incorporated directly into the capital cost estimate and provides a market-based foundation for key portions of the Project cost.

The Company then developed estimates for Owner's Costs, including project development, engineering, permitting, owner's engineering, project management, Company labor, land acquisition, and other costs incurred directly by the Company to support project development and execution. Finally, the estimate includes contingency intended to address identified project risks and remaining uncertainties associated with the Project at its current stage of development. Witness Banks provides additional testimony regarding the Company's approach to identifying, evaluating, and quantifying project risks and the resulting contingency included in the project estimate.

Q36. What is the Company's current estimate of the transmission network upgrade costs associated with the Livingston County project?

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A36. Based on the results of the MISO 2025 Definitive Planning Phase (DPP) Cycle 1 study process, the Company's current estimate of network transmission upgrade costs associated with the Livingston County project is approximately $232.48 million. This estimate is preliminary and will continue to be refined through the ongoing MISO study process, and the final transmission upgrade costs may differ from the current estimate. As discussed above, these costs are not included in the Livingston County project capital cost estimates I support. Witness Djordjevic provides additional detail regarding the MISO interconnection process and transmission system upgrades associated with the Livingston County project.

Q37. What Certificates of Necessity is the Company seeking with respect to the Livingston County Project?

A37. As described by Witness Pratt, the Company is seeking Certificates of Necessity pursuant to MCL 460.6s(3) that includes a finding that the power to be supplied by the Livingston County Project is needed, that the size, fuel type and design of the Livingston County Project is the most reasonable and prudent means of meeting the Company's power need, and that the estimated $3.925 billion capital cost of the Livingston County project and the associated proposed financing plan will be recoverable in rates.

Q38. What is the estimated capital cost for the Monroe County Project?

A38. The estimated capital cost for the Monroe County project is approximately $2.518 billion, excluding financing costs. The estimated capital cost is summarized in Table 2.

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Table 2 CCS-Ready CCGT Cost Estimate for the 700 MW Monroe County Project (Millions)

Cost Category	Cost
EPC Scope	[redacted]
Owner's Costs	
Contingency	
Total Capital Cost	**$2,518**

The estimated capital cost consists of three principal categories: (1) EPC Scope; (2) Owner's Costs; and (3) Contingency.

The EPC Scope category includes engineering, construction labor, balance-of-plant systems, materials, and other costs necessary to construct and place the facility into service.

Owner's Costs include the PIE, major electrical equipment, project development, permitting, owner's engineering, project management, Company labor, land acquisition, and other costs incurred directly by the Company to support project development and execution. As discussed by Witness Banks, procurement activities have been completed for major equipment scopes, including the PIE, generator step-up transformers, unit auxiliary transformers, and high-voltage breakers.

Contingency represents funding included in addressing identified project risks and remaining uncertainties associated with the Project at its current stage of

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development. Witness Banks provides testimony regarding the Company's approach to identifying, evaluating, and quantifying project risks and the resulting contingency included in the project estimate.

Q39. How was the capital cost estimate for the Monroe County Project developed?

A39. The capital cost estimate for the Monroe County Project was developed using a combination of project-specific engineering, completed procurement activities, vendor quotations, and industry-standard cost estimating practices.

To develop the EPC scope portion of the estimate, the Company's Owner's Engineer, Burns & McDonnell, prepared a project-specific Class 4 cost estimate for the Monroe County Project. The Monroe County estimate utilizes the detailed engineering, quantities, and cost structure developed for the Livingston County Project as its foundational basis, with adjustments to reflect the Monroe County Project's single-train 1x1 configuration and site-specific characteristics.

The underlying Livingston County Project estimate was supported by project-specific engineering and design development, including civil grading and drainage plans, piping and instrumentation diagrams, a single-line electrical drawing, conceptual architectural layouts, utility routing studies, and project-specific quantity takeoffs. Burns & McDonnell leveraged this engineering foundation and applied discipline-specific scaling, estimating methodologies, and site-specific adjustments to develop the Monroe County Project estimate. In addition, Burns & McDonnell developed the cost estimate assuming an EPC execution approach utilizing multiple subcontractors under an open book commercial structure, which

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Burns & McDonnell identified as consistent with current market conditions. This contracting methodology is consistent with the approach selected for the Monroe County Project as described by Witness Banks.

Burns & McDonnell also obtained budgetary quotations for third-party equipment and materials and reviewed third-party labor studies to inform construction cost assumptions. In addition, the Company completed competitive procurement activities for major equipment scopes, including the PIE, generator step-up transformers, unit auxiliary transformers, and high-voltage breakers. Pricing obtained through those procurement activities was incorporated directly into the capital cost estimate and provides a market-based foundation for key portions of the Project cost. Additional details regarding the EPC scope cost estimate are provided in Confidential Exhibit A-16.1, NDA Monroe County Project EPC Capital Cost Estimate.

The Company then developed estimates for Owner's Costs, including project development, engineering, permitting, owner's engineering, project management, Company labor, land acquisition, and other costs incurred directly by the Company to support project development and execution. Finally, the estimate includes contingency intended to address identified project risks and remaining uncertainties associated with the Project at its current stage of development. Witness Banks provides additional testimony regarding the Company's approach to identifying, evaluating, and quantifying project risks and the resulting contingency included in the project estimate.

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Q40. What is the Company's current estimate of the transmission system upgrade costs for the Monroe County Project?

A40. As described by Witness Djordjevic, the Monroe County interconnection requests are currently scheduled to be studied through MISO's DPP-2026 interconnection cycle, therefore preliminary study results are not yet available.

Q41. What Certificates of Necessity is the Company seeking with respect to the Monroe County Project?

A41. The Company is seeking Certificates of Necessity pursuant to MCL 460.6s(3) that includes a finding that the power to be supplied by the Monroe County Project is needed, that the size, fuel type and design of the Monroe County Project is the most reasonable and prudent means of meeting the Company's power need, and that the estimated $2.518 billion capital cost of the Monroe County project and the associated proposed financing plan will be recoverable in rates.

Q42. Why does the Company believe the capital cost estimates for the Livingston County project and Monroe County project are reasonable?

A42. The Company believes the capital cost estimates for both Projects are reasonable at their current stage of development because they are based on a combination of current market pricing, project-specific engineering development, and industry-standard estimating practices.

As described previously, the estimates incorporate vendor-provided pricing and executed agreements for major equipment, including the PIE, generator step-up transformers, unit auxiliary transformers, and high-voltage breakers. The PIE

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pricing and executed agreements for key electrical equipment were obtained through competitive procurement processes and anchor the estimates in current market conditions for the Projects' critical components. Witness Banks provides additional testimony regarding the procurement processes used for these major equipment scopes and the resulting contractual arrangements.

Both Projects' capital cost estimates are further supported by a Class 4 cost estimates developed by the Company's Owner's Engineer, Burns & McDonnell, and based on a meaningful level of project-specific engineering and design development.

Burns & McDonnell has extensive experience supporting the development, engineering, estimating, and execution of combined-cycle generating facilities and currently serves as both an Owner's Engineer and EPC contractor on combined-cycle projects throughout North America. This experience provides Burns & McDonnell with current market knowledge regarding power generation facility design, construction methods, labor requirements, project execution considerations, and equipment pricing.

For the Livingston County project, engineering includes civil grading and drainage plans, piping and instrumentation diagrams, electrical single-line drawings, conceptual architectural layouts, and project-specific quantity takeoffs. These engineering deliverables provide a strong technical basis for estimating construction scope and cost. The Monroe County project estimate uses that

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engineering foundation, appropriately adjusted for its single-train 1x1 configuration and site-specific characteristics.

The estimate is further supported by budgetary quotations for third-party equipment and materials and construction labor assumptions informed by third-party labor studies, ensuring that both material and labor costs reflect current market conditions.

Finally, each estimate includes contingency intended to account for uncertainties associated with the Projects at this stage of development. Witness Banks describes the Company's approach to identifying, evaluating, and quantifying project risks and the resulting contingency included in the project estimates.

Based on these factors, the Company believes the capital cost estimates are market-informed, engineering-based, and appropriately reflect the remaining development uncertainty and are reasonable for purposes of this filing.

Q43. How do the estimated capital costs of the Projects compare to similar combined-cycle projects?

A43. Witness Lind provides a comparative assessment of the EPC cost portion of the Livingston County project and Monroe County project estimates against recent utility-sponsored combined-cycle projects around the country. His analysis considers differences among those projects and, where appropriate, adjusts the comparisons to provide a more consistent basis for evaluating the proposed Projects. Witness Lind concludes that the proposed capital cost estimates for the

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Projects fall within a zone of reasonableness when appropriately compared with similar projects.

Part V: Operations, Maintenance, and Operating Cost Estimates

Q44. What are the expected operations and maintenance requirements of the proposed facilities?

A44. The Livingston County project and Monroe County project will require ongoing plant operations, routine and preventative maintenance, major equipment maintenance, inspections, and periodic refurbishment or replacement of equipment over their operating lives.

Operations personnel will monitor plant systems and start, stop, and operate the combined-cycle trains in response to dispatch instructions and system conditions. Maintenance activities will include preventive, predictive, condition-based, and corrective maintenance of the combustion turbines, steam turbines, HRSGs, generators, and balance-of-plant equipment.

The Projects' O&M programs will be developed using equipment manufacturer requirements, operating experience, equipment condition, and applicable regulatory requirements to support reliable operation over the expected 30-year operating life.

Q45. What are the principal drivers of O&M costs?

A45. The principal drivers for O&M costs include plant staffing, routine maintenance, major equipment maintenance, consumables, replacement parts, and other

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materials and services required to operate and maintain the facility. The staffing component includes operations and maintenance personnel responsible for plant operations, maintenance planning and execution, technical support and outage planning. Consumables, such as water treatment chemicals and lubricants, are required for plant operation and to maintain equipment and environmental control systems within applicable operating requirements.

Q46. How are the Projects' major maintenance requirements and associated costs determined?

A46. For the combustion turbines, the equipment manufacturer establishes maintenance intervals based on operating hours, starts, and the operating conditions experienced by the equipment. For the selected combustion turbines, major maintenance planning includes combustion inspections, hot-gas-path inspections, and major inspections based on equivalent operating hours and equivalent start thresholds established by the manufacturer. The current maintenance basis assumes major inspection intervals associated with approximately 32,000 equivalent operating hours or 900 equivalent starts, subject to the manufacturer's applicable maintenance criteria and the Projects' actual operating experience.

These inspections involve examination, refurbishment, and replacement of combustion system, turbine, compressor, and other major components as required. The combustion turbines will also undergo periodic borescope inspection to assess equipment condition and support outage planning.

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Each of the heat recovery steam generators will undergo offline inspection and condition-based maintenance, generally coordinated with outages of its associated combustion turbine. The steam turbines, generators, and balance-of-plant equipment will likewise require periodic inspection, maintenance, refurbishment, and component replacement over the Projects' operating lives.

Major maintenance costs are forecasted based on these manufacturer-established maintenance requirements and the anticipated inspection, refurbishment, and replacement activities over the expected operating lives of the Projects.

Q47. Does the Company anticipate entering into a long-term service agreement for the Projects' combustion turbine equipment?

A47. Yes. The Company intends to enter into a long-term service agreement (LTSA) with GE Vernova for the Projects' combustion turbine equipment. The LTSA is expected to support planned maintenance of the combustion turbine equipment over the term of the agreement, and the forecasted O&M costs I discuss below include the O&M-related costs associated with the LTSA.

Q48. How were the O&M cost forecasts for the Projects developed?

A48. The O&M cost forecasts were developed with support from the Company's Owner's Engineer, Burns & McDonnell, based on the selected generating technology, proposed Projects' facility configurations, anticipated staffing and operating requirements, manufacturer maintenance requirements, consumables and replacement parts requirements, and the planned use of an LTSA for the combustion turbine equipment.

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The forecasts include both fixed and variable O&M components. Fixed O&M reflects costs that are expected to be incurred largely independent of the Projects' output, including plant staffing and other recurring plant costs. Variable O&M reflects costs that vary with plant operation and electricity production, including operating consumables and other usage-related costs.

The forecasts also reflect the major maintenance requirements described above and the different configurations of the two Projects: two 1x1 combined-cycle trains with the Livingston County project, and one 1x1 combined-cycle train with the Monroe County project.

Q49. What are the forecasted O&M costs for the Livingston County project?

A49. Current staffing forecasts for the Livingston County Project assume approximately 40 full-time employees.

Fixed plant O&M costs, including the O&M portion of the LTSA, are forecasted at approximately $15 million per year. Variable O&M costs are forecasted at approximately $1.6/MWh during unfired operation, with an incremental $0.7/MWh for duct-fired operation.

These forecasts were developed with support from Burns & McDonnell based on the design and expected operating characteristics of the proposed Project.

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No.

O&M costs do not include natural gas fuel costs. These forecasts represent the Company's current estimate of the staffing, operating, and maintenance resources required to safely and reliably operate the facility.

Q50. What are the forecasted O&M costs for the Monroe County Project?

A50. Current staffing forecasts for the Monroe County Project assume approximately 30 full-time employees.

Fixed plant O&M costs, including the O&M portion of the LTSA, are forecasted at approximately $10 million per year. Variable O&M costs are forecasted at approximately $1.6/MWh during unfired operation, with an incremental $0.7/MWh for duct-fired operation.

These forecasts were developed with support from Burns & McDonnell based on the design and expected operating characteristics of the proposed Project.

O&M costs do not include natural gas fuel costs. These forecasts represent the Company's current estimate of the staffing, operating, and maintenance resources required to safely and reliably operate the facility.

Q51. Why are the projected O&M costs reasonable?

A51. The Company believes the projected O&M costs are reasonable because they were developed by Burns & McDonnell based on the design, equipment configuration, and expected operating characteristics of the proposed facilities.

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No.

Burns & McDonnell has extensive experience supporting the development, engineering, estimating, construction, and operation of combined-cycle generating facilities throughout North America. The O&M forecasts reflect the specific configuration of the proposed facilities, including the advanced-class combustion turbine technology, anticipated staffing requirements, planned maintenance activities, and LTSA requirements.

In addition, the forecasts were developed using industry-standard estimating practices and information derived from comparable combined-cycle generating facilities. Based on these factors, the Company believes the projected O&M costs provide a reasonable estimate of the staffing, operating, and maintenance resources required to safely and reliably operate the facilities.

Part VI: Planned Implementation of CCS

Q52. Are carbon capture systems included in the initial construction scope of the Livingston County and Monroe County Projects?

A52. No. Carbon capture systems are not included in the construction scope of the Livingston County or Monroe County Projects, and the project capital cost estimates presented in my testimony do not include the future cost of carbon capture equipment or associated infrastructure.

Instead, both facilities are being developed as CCS-ready projects, meaning they are being designed to accommodate the future integration of CCS when such systems are implemented to comply with Michigan's Clean Energy Standard.

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What is the Company's planned timing for CCS implementation, and why are the Projects being developed using a phased approach?

A53. The Livingston County Project is expected to be commercially operational in 2031, and the Monroe County Project is expected to be commercially operational in 2032. The Company is developing the Projects using a phased approach in which CCS-ready features are incorporated into the initial CCGT design while carbon capture, transportation, and storage systems are developed for future implementation in support of compliance with Michigan's Clean Energy Standard.

This phased approach allows the CCGTs to begin providing firm, dispatchable capacity and energy when needed while sequencing CCS implementation as a subsequent phase of development. The Company believes this approach is prudent because it enables the Company to focus on the timely development and construction of the CCGT facilities while continuing to advance CCS-related engineering, transportation, storage, permitting, and commercial development activities. In addition, the phased approach provides additional time for carbon capture technology and supporting infrastructure to continue maturing before CCS implementation is required to support compliance with Michigan's Clean Energy Standard. Incorporating CCS-ready features during initial project development helps preserve the ability to efficiently integrate carbon capture systems in the future as those activities continue to advance.

Witness Pratt provides additional testimony regarding the sequencing of the CCGT resources and future CCS implementation, while Witness Hajj addresses the

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relationship between that sequencing and planned compliance with the Clean Energy Standard.

Q54. How would implementation of CCS affect the operating characteristics of the Projects?

A54. Implementation of CCS would increase the Projects' energy consumption and reduce their net generating output because a portion of the facility's energy production would be used to operate the carbon capture systems and associated support equipment. Based on the Company's current evaluation of CCS technology, implementation of CCS is expected to increase the Projects' net heat rate by approximately 1,920 Btu/kWh and reduce net plant output by approximately 4 percent. These impacts reflect the additional energy required to capture, process, compress, and handle carbon dioxide emissions.

Q55. What work has the Company performed to evaluate CCS integration?

A55. The Company has completed a variety of development and engineering activities to evaluate the technical requirements associated with planned future CCS implementation at the Projects' facilities.

The Company commissioned a CCS pre-front-end engineering and design (pre-FEED) study with Mitsubishi Heavy Industries (MHI) to evaluate the integration of carbon capture technology with advanced-class combined-cycle generating facilities and to identify design considerations that could facilitate future implementation. The results of this work are provided in Exhibit A-16.2, Carbon Capture Pre-FEED Study.

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In addition, the Company's Owner's Engineer, Burns & McDonnell, incorporated future CCS considerations into the facility design and general arrangement drawings for the proposed Projects, including facility layout, utility routing, and space requirements necessary to support future CCS implementation.

Collectively, these efforts informed the CCS-ready design features incorporated into the Livingston County and Monroe County Projects and the Company's ongoing evaluation of future CCS deployment.

Q56. What work has the Company performed to evaluate geologic carbon storage opportunities associated with future CCS implementation?

A56. The Company participated in a U.S. Department of Energy CarbonSAFE project conducted by Battelle to evaluate the feasibility of permanent geologic carbon dioxide sequestration in Southeastern Michigan.[1] As part of that effort, Battelle performed regional geologic evaluations, seismic analysis, reservoir modeling, and site screening activities to identify areas with potential suitability for geologic carbon storage. Battelle ultimately drilled a stratigraphic test well in Monroe County to collect site-specific geological information regarding formations being evaluated for potential carbon storage.

The test well was drilled to obtain information regarding formation thickness, porosity, permeability, and other geologic characteristics relevant to carbon

[1] Battelle Memorial Institute, *Carbon Storage Complex Feasibility for Commercial Development in Southeastern Michigan – CarbonSAFE Phase II* (U.S. Department of Energy Award No. DE-FE0032312). The project included regional geologic characterization, drilling of a stratigraphic test well, reservoir evaluation, and assessment of geologic carbon storage opportunities in Southeastern Michigan.

storage. Preliminary findings from the project identified positive indicators for future carbon storage development, with additional laboratory analysis and reservoir modeling subsequently performed by Battelle.

This work provided the Company with information regarding regional sequestration opportunities and informed the Company's evaluation of the storage component of a future CCS system.

Q57. How do the Company's CCS development activities support the feasibility of planned future CCS implementation at the Projects?

A57. The Company's CCS development activities evaluated each of the principal components necessary to support future CCS implementation, including carbon capture technology, facility integration requirements, carbon dioxide transportation infrastructure, and permanent geologic sequestration.

The MHI pre-FEED study demonstrated a technically feasible pathway for integrating carbon capture technology with the proposed advanced-class combined-cycle facilities and developed a preliminary design basis for a system capable of achieving a carbon dioxide capture rate greater than 90%.

In addition, the Battelle test well project provided geological data and analysis to support the Company's evaluation of potential geologic sequestration opportunities in Southeastern Michigan. Together, these development activities address the major elements necessary for carbon capture and storage, including capture, transportation, and permanent geologic sequestration.

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No.

Based on these evaluations, the Company believes the Livingston County and Monroe County Projects have a technically feasible pathway for future CCS implementation. Witness Hajj addresses how planned future CCS implementation helps support the Company's compliance with Michigan's Clean Energy Standard.

Q58. Has the Company evaluated the potential cost of future CCS implementation?

A58. Yes. As part of its CCS development activities, the Company evaluated the potential cost of future CCS implementation for the proposed facilities. Tables 3 and 4 provide a preliminary CCS cost estimate developed for planning purposes.

The estimated cost of the carbon capture plant includes a Major Equipment component derived from the MHI CCS pre-FEED study, which is provided as Confidential Exhibit A-16.2, and a Balance of Plant component derived from a Burns & McDonnell assessment of the additional balance-of-plant infrastructure, facility modifications, and associated costs that may be required to support CCS implementation, which is provided as Confidential Exhibit A-16.3. The Transport and Storage estimate and Owner's Costs estimate were developed through the Company's internal evaluations of potential carbon dioxide transportation, geologic sequestration, project development, and related implementation requirements.

As shown in Table 3 and Table 4, the Company's preliminary evaluation indicates a total CCS system cost of approximately $4.6 billion for the 1,400 MW Livingston County Project and approximately $2.5 billion for the 700 MW Monroe County Project. These evaluations were performed to better understand the feasibility, infrastructure requirements, and potential cost implications associated with future

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CCS deployment and are preliminary estimates only. The Company expects that any future CCS cost estimates would continue to evolve based on technology development, project-specific engineering, transportation and storage solutions, permitting requirements, market conditions, and the timing of any future CCS implementation.

Table 3 Preliminary CCS Cost Estimate for the 1,400 MW Livingston County Project (Millions)

CCS Cost Component	Cost
Carbon Capture Plant	
Engineering, Major Equipment, and Construction	
Balance of Plant	
Total Carbon Capture Plant	
Transport and Storage	
Owner's Costs	
Total CCS System	**$4,553**

Table 4 Preliminary CCS Cost Estimate for the 700 MW Monroe County Project (Millions)

CCS Cost Component	Cost
Carbon Capture Plant	
Engineering, Major Equipment, and Construction	
Balance of Plant	

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CCS Cost Component	Cost
Total Carbon Capture Plant	[redacted]
Transport and Storage	
Owner's Costs	
Total CCS System	**$2,532**

Q59. Is the Company seeking approval of CCS construction costs in this proceeding?

A59. No. While the Company has evaluated the potential cost of future CCS implementation, the CCS-ready CCGT capital cost estimates presented in my testimony do not include the future cost of carbon capture facilities, carbon dioxide transportation infrastructure, sequestration facilities, or other CCS-related construction costs. These projects are being developed as CCS-ready facilities, and the Company is seeking approval of the generation facilities and associated CCS-ready design features necessary to preserve the ability to integrate CCS in the future.

Q60. When does the Company expect to seek approval of CCS implementation costs?

A60. The Company expects to seek approval of CCS implementation costs in a future proceeding. As discussed throughout my testimony, the Livingston County and Monroe County Projects are being developed as CCS-ready facilities and are intended to support the Company's long-term compliance strategy under Michigan's Clean Energy Standard.

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No.

Because CCS implementation is not required immediately upon commercial operation of the Projects, the Company expects to utilize the time available before implementation is needed for Clean Energy Standard compliance to allow carbon capture technology to continue maturing. As development activities progress, the Company expects to further refine the scope, schedule, and cost of future CCS implementation.

As needed to support compliance with Michigan's CES, the Company will return to the Commission in a future proceeding to seek approval of the applicable CCS facilities and associated costs. At that time, the Company will present a more fully developed project scope and cost estimate to support Commission review and approval.

Q61. Why is the Company's proposed phased approach to CCS implementation reasonable and appropriate?

A61. The Company's proposed phased approach is reasonable and appropriate because it balances the near-term need for firm, dispatchable generation, as discussed by Witnesses Manning and Pratt, with the long-term objective of implementing CCS to support compliance with Michigan's Clean Energy Standard.

The proposed Projects are being developed as CCS-ready facilities, preserving a pathway for future CCS implementation while allowing the Company to incorporate continuing advancements in carbon capture technology, transportation infrastructure, and geologic sequestration solutions into future CCS deployment plans.

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No.

Accordingly, the phased approach provides a balanced and prudent path forward that supports reliable service for customers and future compliance with Michigan's Clean Energy Standard.

Part VII: Support for CON Determinations and Conclusion

Q62. What conclusions have you reached based on the project development work as described in your testimony?

A62. Based on the development work completed to date, I believe the Livingston County project and Monroe County project are sufficiently developed to support the project-specific technical, operating, and capital cost information presented in this filing and represent reasonable and prudent solutions to address the Company's identified capacity needs.

As discussed throughout my testimony, the Company has established site control and evaluated the development characteristics of the proposed sites; selected advanced-class CCGT technology and configurations based on defined technical and operating considerations; advanced project-specific engineering and design; developed capital cost and O&M estimates using current equipment pricing, engineering, and operating assumptions; and incorporated CCS-ready design features informed by engineering and development work supporting planned future CCS implementation.

The resulting Projects' designs and associated capital cost and O&M estimates provide a reasonable and supportable technical basis for the Livingston County project and Monroe County project at their current stage of development.

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No.

Witness Pratt addresses the Company's determination that the size, fuel type, and other design characteristics of the Projects represent the most reasonable and prudent means of meeting the identified power need, while Witness Manning provides the supporting resource planning and modeling analyses which establish the need for additional firm, dispatchable generation resources.

Q63. How does your testimony support the applicable CON requirements?

A63. My testimony provides project-specific technical and cost support for the Company's proposed Livingston County and Monroe County generation facilities and the associated CON requests.

Specifically, my testimony demonstrates that the proposed facilities are appropriately sized, designed, and expected to be available on a timetable consistent with the resource need identified in the Company's Integrated Resource Plan and described by Witness Manning. I describe the proposed project sites, expected generation technology, major facility design characteristics, generating capacity, anticipated operating life, fuel supply considerations, and other significant operational characteristics, demonstrating that the facilities are capable of providing the reliable, dispatchable generation needed to meet the Company's future customer and system needs.

I also describe the Company's technology selection process, the CCS-ready design features incorporated into the projects, and the development work performed to support future CCS implementation, supporting the reasonableness and prudence of the proposed facility designs.

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In addition, I provide testimony regarding the estimated capital costs of the proposed projects, the basis for those estimates, and the reasons the Company believes those estimates are reasonable and supportable.

Collectively, this testimony supports the Company's conclusion that the proposed facilities represent reasonable and prudent generation resources whose size, technology, operating characteristics, anticipated timing, and CCS-ready design are aligned with the resource need identified in the Company's IRP and described by Witness Manning.

Q64. Does this conclude your direct testimony?

A64. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

PUBLIC DIRECT

TESTIMONY OF

MICHAEL E. BANKS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MICHAEL E BANKS

Line No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name is Michael E. Banks. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy as a Director of Major Projects in the Project Management Office.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from Michigan State University with a Bachelor of Science degree in Civil Engineering in 2002. I also hold a Master of Science degree in Civil Engineering from Wayne State University, received in 2006.

Q4. What is your professional experience?

A4. In 1999, I was hired into DTE Electric as an engineer in the Distribution Operations Service Center Operations group. In 2003, I transitioned to the Environmental Management & Resources (EM&R) organization as a power plant environmental engineer. In 2007, I joined the Continuous Improvement organization as a Project Lead. In 2009, I transitioned to Belle River Power Plant as the Maintenance Manager. In 2012, I was promoted to Supervisor of the Continuous Improvement group. In 2013, I was promoted to Supervisor of the Combustion and Draft group in the Engineering Support Organization. In 2014, I was promoted to Performance Manager of the Lab and Field Support group of the Engineering Support Organization. In 2015, I was promoted to Manager, Power Generation Engineering within the Engineering Support Organization responsible for the New Gas

Generation group. This group is responsible for the technical development and management of new natural gas fueled electric generation options for DTE Electric, including Blue Water Energy Center. In 2019, I was promoted to Plant Manager – Energy Supply of the Blue Water Energy Center. In this role I was responsible for the continued engineering and commissioning of the facility, hiring of permanent staff, and preparing all aspects of the plant for commercial operation.

Q5. What are your current duties and responsibilities?

A5. In 2022, I was promoted to Director of Major Projects – Project Management Office. In this role, I lead a team that executes generation projects for DTE Electric's Energy Supply assets including decommissioning of retired assets, construction of new gas-fired electric generation assets, and environmental-related work.

Q6. Do you have experience working on combined cycle power plant development, construction, and commissioning?

A6. Yes. I was the lead engineering manager for the Blue Water Energy Center which is the 1,146 MW combined cycle gas turbine (CCGT) power plant that was approved by the Commission in the Company's Certificate of Necessity (CON) Case No. U-18419. I was one of the first employees assigned to the project and was responsible for the technical evaluation of the technology. As the project progressed, I took on responsibility for the engineering development, commissioning, and initial operation of the facility. I worked closely with the construction team and was on site daily over the course of the four-year

construction phase. When I left the plant, I was the plant manager responsible for all aspects of operating the facility.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I sponsored testimony in the following cases:

Case No.	Description
U-17319-R	2014 PSCR Reconciliation Case
U-17680-R	2015 Power Supply Recovery (PSCR) Reconciliation Case
U-18419	DTE Electric 2017 Certificates of Necessity
U-21772	DTE Electric Depreciation

Line No.

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to support the project execution responsibilities of the Livingston County project and Monroe County project (Projects) included in the Company's 2026 Integrated Resource Plan (IRP) and associated requests for Certificates of Necessity (CON). My testimony focuses on project execution matters, and:

- Describes the contracting and procurement strategy for the Projects' major equipment, engineering, and construction;
- Explains the Company's progressive Engineering, Procurement, and Construction (EPC) strategy and the project controls that will be used to manage cost, schedule, quality, and execution;
- Describes the construction workforce requirements and the Company's approach to workforce availability and use of Michigan labor;
- Describes the Projects' risk management process, risk registers, and associated contingency;
- Supports the execution schedule for the Projects, and the major milestones necessary to achieve the planned commercial operation dates (COD);
- Describes the Company's approach to coordinating permitting and other required approvals associated with the execution of the Projects;
- Describes off-site and other infrastructure requirements necessary to support construction and execution of the Projects; and
- Addresses decommissioning considerations associated with the Projects.

Line No.

Q9. What is the division of responsibilities among Company witnesses related to the development and execution of Livingston County and Monroe County projects?

A9. Witness Stansell and I address complementary aspects of the Projects. Witness Stansell primarily addresses the early-stage development and technical definition of the Projects, while my testimony focuses primarily on Project execution. The division of responsibilities regarding early project development and project execution are summarized in Table 1.

Table 1 Witness Responsibilities: Project Development & Execution

Project Development (Witness Stansell)	**Project Execution** (Witness Banks)
Site selection and site control	Contracting and execution strategy
Technology selection and facility configuration	Major equipment procurement and contracting
Capital cost estimate development and reasonableness	EPC selection and contracting
O&M planning and cost assumptions	Project controls and governance
Carbon Capture and Storage (CCS) - ready design considerations	Project risk and contingency
Project-specific community engagement and socioeconomic considerations	Construction workforce and labor planning
Technical and operating characteristics	Project schedules and major execution milestones
	Major permitting coordination
	Infrastructure upgrades and logistics
	Decommissioning considerations

Line No.

Q10. Are you sponsoring any exhibits?

A10. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-17	Livingston County Project Construction Labor Curve
A-17.1	Livingston County Project Schedule
A-17.2	NDA Livingston County Project Risk Register
A-17.3	Livingston County Project Permit Matrix
A-17.4	Monroe County Project Construction Labor Curve
A-17.5	Monroe County Project Schedule
A-17.6	NDA Monroe County Project Risk Register
A-17.7	Monroe County Project Permit Matrix

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes. They were.

Q12. Can you briefly describe the projects you are supporting with your testimony?

A12. Yes. My testimony addresses the two Company-owned, CCS-ready CCGT Projects described in greater detail by Witness Stansell:

- The Livingston County project, planned for Handy Township, Livingston County, Michigan, with an approximate nominal capacity of 1,400 MW and consisting of two (2) 1x1 single-shaft combined-cycle trains.
- The Monroe County project, planned for Milan Township, Monroe County, Michigan, with an approximate nominal capacity of 700 MW and consisting of one (1) 1x1 single-shaft combined-cycle train.

As described above, my testimony addresses the plans, contracts, controls, workforce, schedules, permitting coordination, and other execution activities necessary to construct and place these Projects into commercial operation. Witness Stansell provides additional testimony regarding the Projects' sites, technology, configuration, operating characteristics, and development.

Q13. How is your testimony organized?

A13. My testimony is separated into three (3) sections.

Section 1 addresses topics that are applicable to both the Livingston County and Monroe County projects and will include the following five (5) parts:

Part I – Contracting Strategy and Major Project Contracts
Part II – Competitive Procurement, Bid Evaluation, and Contract Awards
Part III – Project Controls, Governance, Risk Management, and Contingency
Part IV – Construction Workforce and Labor Requirements
Part V – Decommissioning Considerations

Section 2 addresses project execution details specific to the Livingston County project and will include the following four (4) parts:

Part I – Contingency and Risk Register
Part II – Project Schedule and Major Milestones
Part III – Permitting
Part IV – Infrastructure Upgrades and Logistics

Section 3 addresses project execution details specific to the Monroe County project and will include the following four (4) parts:

Part I – Contingency and Risk Register

Part II – Project Schedule and Major Milestones

Part III – Permitting

Part IV – Infrastructure Upgrades and Logistics

SECTION 1 – TOPICS APPLICABLE TO BOTH LIVINGSTON COUNTY AND MONROE COUNTY PROJECTS

Part I: Contracting Strategy and Major Project Contracts

Q14. How is the Company structuring major contracts needed to execute the Livingston County project and Monroe County project?

A14. The Company has identified several principal contracting scopes necessary to execute CCGT projects of this scale:

- Owner-Furnished Equipment (OFE) contracts, which include:
  - Power Island Equipment (PIE): The PIE scope includes the equipment, engineering, and technical support associated with combustion turbine(s), electrical generator(s), steam turbine(s), heat recovery steam generator(s) (HRSG), and digital control system (DCS). As discussed by Witness Stansell, the Company pre-selected GE Vernova (GE), Mitsubishi Power, and Siemens Energy – commonly known as the Original Equipment Manufacturers (OEMs). The OEM is responsible for design, manufacturing, and testing of the equipment to meet its specifications,

deliver it to the project site, and provide technical oversight during its construction, installation, and commissioning.

- Major Electrical Equipment: These scopes include the equipment, engineering, and technical support associated with major electrical systems necessary to support the generating facilities and their connection to the electric transmission system. These components include the generator step-up (GSU) transformers, unit auxiliary transformers (UATs), and high-voltage breakers (HVBs).

- Engineering, Procurement, and Construction (EPC): This scope includes detailed engineering, procurement of the balance of equipment and materials, construction, and support for commissioning of the CCGT facility. Due to the scale and complexity of CCGT projects, companies are limited on which are qualified to perform this scope of work. As I discuss below, the Company selected a progressive split EPC approach for this scope.

Q15. What considerations informed the Company's contracting approach for the PIE scope for the Projects?

A15. The Company's contracting approach for the PIE scope of the Projects considered cost, equipment performance, integration risk, and schedule. Negotiating for major power island components separately, rather than procuring the equipment as a single power island package, can give the Company more control over equipment selection, but it also places more equipment integration and performance risk on DTE Electric and requires additional engineering and interface management from its Owner's Engineer (OE), Burns & McDonnell.

A PIE approach, by contrast, places greater responsibility for the integrated performance of the major PIE with a single OEM.

After weighing the benefit of the integration expertise of one qualified, experienced OEM who stands behind performance with a PIE agreement against the potential savings of procuring individual components and integrating their performance as an Owner, the Company selected the PIE agreement. Under the PIE agreement, DTE Electric still holds control over and input into technology selection.

Q16. What principal contracting approach did the Company consider for the EPC scope of the Projects?

A16. There are several EPC contracting structures that are used in large construction projects. The principal variations differ in how scope is defined, how pricing is established, and how cost and execution risk are allocated between the owner and the contractor. Described below, these structures generally include: (1) time and materials, (2) cost-reimbursable or cost-plus, (3) target price or guaranteed maximum price, (4) lump-sum turnkey, (5) progressive EPC, and (6) split engineering-procurement plus construction, or Ep+C.

1. **Time and materials:** the owner generally pays the contractor for actual labor hours, materials, equipment, and approved markups. This structure provides flexibility when scope is not fully defined, but it places more cost risk on the owner and requires strong oversight of productivity, staffing, procurement, and schedule performance.

Line No.

2. **Cost-reimbursable/cost-plus:** the owner reimburses the contractor for allowable costs and pays an agreed fee. This approach can be useful during early development or where design maturity is limited because it supports collaboration and transparency; however, it requires clear cost controls, audit rights, and governance to manage Project risk.
3. **Target price/guaranteed maximum price:** the contractor and owner establish a target price or maximum price for a defined scope, often with sharing mechanisms for cost underruns or overruns. This approach can provide more cost discipline than a pure cost-reimbursable model while preserving collaboration during development.
4. **Lump-sum turnkey EPC:** a single EPC contractor provides engineering, procurement, construction, commissioning support, and defined performance commitments for a fixed price. This structure can provide greater price certainty and transfer more execution risk to the EPC contractor, but that risk transfer may come at a higher cost, particularly when design is not sufficiently mature or market conditions are volatile.
5. **Progressive EPC:** sometimes referred to as an open-book to closed-book model, this is a phased approach. During the open-book phase, the contractor advances engineering, procurement planning, constructability, schedule development, and a detailed estimate with owner visibility into cost inputs. Once the project is more defined, the parties may transition to a closed-book or fixed-price arrangement for defined scopes of work.
6. **Split Ep+C:** engineering and procurement responsibilities are separated from construction responsibilities while the owner retains responsibility for overall integration and project governance. This structure can allow the

owner to select contractors based on their respective strengths, improve transparency into engineering and construction cost development, and better align risk allocation with the parties best positioned to manage those risks.

Q17. Which EPC contracting approach did the Company select and why?

A17. The Company selected a combination of Progressive EPC and Split Ep+C contracting approach for the Projects, which is referred to hereafter as the Progressive Split Ep+C (progressive Ep+C) contracting approaches.

Under this approach, the Company uses one contracting scope for engineering and procurement, and a second contracting scope for construction, while advancing those workstreams through a coordinated progressive development process. For each of the Projects, those workstreams will be coordinated through one overall project schedule, cost-development process, and execution plan.

Q18. Did the Company evaluate an EPC approach in addition to the Ep+C approach?

A18. Yes. DTE Electric received two responses to the Request for Proposal (RFP) that included an EPC execution approach. However, these responses were not selected based on the overall scorecard results. The RFP selection process is discussed in detail later in this testimony.

Q19. Why did the Company select a progressive Ep+C contracting approach?

A19. The Company selected this approach because it best fits the risks of these projects. A CCGT project of this size requires strong engineering and procurement capability early in the project, but it also requires strong construction execution and access to qualified craft labor during the field execution period. Separating these scopes through the progressive Ep+C approach allows the Company to address both needs directly by selecting contractors based on their respective capabilities while maintaining overall responsibility for project integration and governance.

The progressive structure also provides cost transparency while engineering and construction planning are in development, allows the Company to evaluate and challenge cost inputs before fixed pricing is established, and reduces the need to pay contractors to assume risks that are not yet sufficiently defined. As project definition increases, the Company expects to establish fixed pricing for defined scopes of work.

Q20. Why is the Ep+C approach reasonable and prudent?

A20. The Ep+C is a reasonable and prudent approach for this project because it supports the project schedule, improves cost transparency, allows DTE Electric to evaluate and challenge cost inputs before fixed pricing is established, and helps avoid unnecessary early-stage risk premiums for the Projects.

Q21. Can you describe the pricing approach of the progressive Ep+C contract?

A21. Yes. Under the progressive Ep+C approach, engineering, procurement planning, construction planning, and cost development are advanced on an open-book basis before final pricing is established for defined scopes.

At the current stage of project development, the design, procurement plan, construction sequence, labor plan, and schedule continue to be refined. Requiring a fixed price too early would require the contractors to price risks and uncertainty before the underlying scope and execution requirements are sufficiently defined, understood, and real, which can increase project cost through additional risk premiums and reduce the Company's visibility into how the price was developed.

Under the selected approach, the Company has visibility into the key inputs used to develop the estimate, including labor assumptions, productivity, material quantities, procurement strategy, schedule assumptions, contingency, and risk allocation. As the Projects become more defined, the Company expects to establish fixed pricing for defined scopes of work.

Q22. Why does the Company believe the progressive Ep+C contracting strategy is appropriate for the Projects?

A22. The Company selected a progressive Ep+C contracting strategy because it provides the most prudent and effective balance of cost, risk, market competitiveness, and execution capability in the current environment for large CCGT projects. This phased approach enables the Company to align the level of cost certainty with the level of project definition, providing transparency during development and price certainty during execution.

The principal benefits of this approach include:

1. **Improved cost transparency and validation:** The open-book phase enables the Company to evaluate pricing inputs, including labor productivity, material

costs, and supply chain considerations, reducing the likelihood of embedded contingencies or unsupported assumptions.

2. **Avoidance of unnecessary cost premiums:** Establishing a fixed price only after sufficient design maturity limits the need for contractors to include significant risk premiums that are typically required under early-stage lump-sum contracts.
3. **Enhanced collaboration and risk mitigation:** Early engagement with engineering and construction contractors supports joint identification and mitigation of risks related to constructability, procurement, and schedule.
4. **Increased bidder participation and competition:** Market feedback indicates that EPC firms are more willing to participate under a progressive, open-book structure, particularly in a constrained labor and supply chain environment.
5. **Eventual cost certainty for execution:** Transitioning to a closed-book, fixed-price contract provides a defined and enforceable cost baseline for the balance of project execution.

As I discuss below, the Company's competitive procurement allowed bidders to propose both traditional EPC and progressive Ep+C approaches, and the responding bidders proposed progressive Ep+C structures rather than a fixed-price, full-wrap EPC arrangement.

Q23. Why does the progressive Ep+C contracting strategy function well under current market conditions?

A23. The Company’s contracting strategy also reflects current constraints in the market for large-scale generation projects, including tightening contractor capacity, supply chain volatility, and limited willingness of contractors to accept broad project risk

under traditional lump-sum turnkey structures at early stages before design and execution requirements are sufficiently defined.

In this context, requiring a fully fixed-price contract at the outset would likely reduce bidder participation and increase overall project cost due to the inclusion of significant contingency premiums for risks that may not materialize. By contrast, the progressive Ep+C approach aligns pricing with project definition and market realities, resulting in a more competitive procurement process and a more efficient allocation of risk. For these reasons, the Company believes that the progressive Ep+C contracting strategy represents a reasonable and prudent approach that supports cost-effective project delivery while maintaining appropriate cost certainty and accountability for the benefit of customers.

Q24. How will the Company control costs and manage risk during the open-book phase of the progressive Ep+C approach?

A24. During the open-book phase, the Company will maintain active oversight of scope, engineering development, procurement assumptions, labor estimates, productivity assumptions, schedule assumptions, proposed contingencies, risk allocation, and contractor cost inputs. The Company will also use its OE, internal subject matter experts, and robust internal project controls to evaluate whether proposed costs are reasonable, supported, and aligned with project requirements before defined scopes transition to a closed-book or fixed-price structure.

The Company's project controls include cost and schedule monitoring, forecasting, change management, risk tracking, and management review. I will discuss those controls and the Projects' risk management framework later in my testimony.

Line No.

Part II: Competitive Procurement and Bid Evaluation

Q25. Did the Company complete a competitive bidding process for the Owners Engineer (OE) scope of work?

A25. Yes. The Company conducted a competitive bidding process for the OE scope of work limited to the engineering firms that had been previously prequalified based on demonstrated experience, capability, and capacity to perform the work.

Q26. How was the competitive bidding process conducted for the OE scope of work?

A26. The competitive bidding process for the OE scope of work was conducted consistent with the Company's guidelines for competitive RFPs and incorporated an assessment of both price and non-price factors. Evaluation criteria included, but were not limited to, quality management, project management and scheduling tools, cost management, risk management, and communication planning.

The OE RFP was issued on April 30, 2024, and five (5) OE suppliers were prequalified to participate. In June 2024, the Company received proposals from three (3) OE suppliers. Following this solicitation, the Company entered into detailed negotiations with one supplier.

Based on the evaluation and subsequent negotiations, the Company selected Burns & McDonnell Michigan, Inc. to provide the OE support for both Projects.

Q27. Did the Company complete a competitive bidding process for the OFE scope of work?

A27. Yes. The Company's competitive bidding process for the PIE scope of work and major electrical equipment was limited to the OEMs that had been previously prequalified based on demonstrated experience, capability and capacity to perform the work. The process is discussed below. This approach ensured that all participating bidders met the Company's technical and operational requirements, while still promoting price competitiveness and market participation. By structuring the bid event in this manner, the Company was able to balance the need for qualified execution with a competitive procurement process, supporting prudent cost outcomes and effective risk management.

Q28. How was the competitive bidding process conducted for the PIE scope of work?

A28. The competitive bidding process for the PIE scope of work was conducted consistent with the Company's guidelines for competitive RFPs and incorporated an assessment of both price and non-price factors. Evaluation criteria included, but were not limited to, technical scope, specification adherence, equipment cost, execution risk, project schedule adherence, commercial terms, and payment forecast.

The PIE RFP was issued on May 29, 2025, and three (3) PIE suppliers were invited to participate. In October 2025, the Company solicited best-and-final pricing and terms from two suppliers. Following this solicitation, the Company entered into detailed negotiations with both suppliers.

Based on the evaluation and subsequent negotiations, the Company selected GE Vernova Operations LLC (GEV) to provide the PIE for both Projects.

As discussed by Witness Stansell, the selected PIE incorporates the GE 7HA.03 combustion turbine and forms the technical basis for the Projects' CCGT configurations and performance assumptions.

Q29. What contracting approach will the Company use for the PIE scope for the Projects?

A29. The Company selected a fixed-price contracting approach for the PIE scope. As part of the fixed price agreements with the OEM, the PIE scope includes contractual requirements addressing equipment delivery, schedule performance guarantees and equipment performance guarantees, together with remedies or penalties for specified non-performance. The performance requirements include electrical output, heat rate, emissions, noise, and operability requirements. I will discuss the specific contractual performance guarantees later in my testimony in connection with the project schedules and major execution milestones.

Q30. How was the competitive bidding process conducted for the major electrical scopes of work?

A30. The Company conducted competitive bidding processes for Generation Step Up transformers (GSUs), Unit Auxiliary Transformers (UATs), and High Voltage Breakers (HVBs) to the Company's approved vendor list for these specific items. Ultimately, an award was issued to Siemens Energy for GSUs, Virgina Transformer for UATs, and Hitachi for HVBs.

The UAT RFP was issued on January 20, 2026, and three (3) suppliers participated. In March 2026, the RFP closed with DTE receiving two bids. Each bid was evaluated and reviewed based on several scoring criteria with a high importance on delivery and schedule. From that evaluation DTE determined that Virgina Transformer was the most viable bid received and selected them to provide the UATs.

Siemens Energy and Hitachi were sole-sourced for the GSUs and HVBs, respectively because they were the lone vendors identified as capable of supporting the required delivery dates for project execution.

Q31. Did the Company complete a competitive bidding process for the EPC scope of work?

A31. Yes. The Company conducted a competitive bidding process among contractors that had been prequalified based on demonstrated experience, capability, and capacity to perform the work. This approach ensured that all participating bidders met the Company's technical and operational requirements, while still promoting price competitiveness and market participation. By structuring the bid event in this manner, the Company was able to balance the need for qualified execution with a competitive procurement process, supporting prudent cost outcomes and effective risk management. The competitive bidding process allowed bidders to propose both traditional EPC and progressive Ep+C contracting approaches.

Line No.

Q32. How was the competitive bidding process conducted for the EPC scope of work?

A32. The competitive bidding process utilized a RFP for the EPC scope that allowed bids for both EPC and Ep+C contracting approaches. The RFP process was conducted consistent with the Company's guidelines for RFPs and incorporated an assessment of both price and non-price factors. The evaluation criteria included, but were not limited to, safety, prior CCGT engineering, procurement, and construction experience, technical submittal information, project schedule, use of union labor, major sourcing of components, cost, financial and credit requirements, and contracting approach. The Company utilized a bid evaluation scorecard that was consistent with these criteria.

The EPC RFP was issued on March 13, 2026, and three (3) prequalified bidder teams were invited to participate. In May, the Company conducted post-bid interviews with all bidders and a best-and-final pricing and terms request was issued to all bidders.

Following this solicitation, the Company entered into detailed negotiations with one bidder team. Ultimately, the Company selected Black & Veatch for engineering and procurement, and Barton Malow Company (Barton Malow) for construction.

The selected contracting team structure forms the progressive Ep+C approach discussed earlier in my testimony.

Q33. Did the Company evaluate alternative contracting structures through the EPC competitive bidding process?

A33. Yes. The Company requested that bidders consider a fixed-price, full-wrap EPC contracting structure. Under a full-wrap EPC contract, a single EPC contractor would assume responsibility for delivering the project under a single contract, including engineering, procurement, construction, schedule performance, and cost performance. However, no bidder elected to pursue that approach. Instead, all bidders proposed progressive Ep+C contracting structures that would allow additional engineering and cost development before establishing final pricing.

The competitive process therefore provided direct market information regarding the contracting structures available for the Projects and informed the Company's selection of the progressive split Ep+C approach.

Q34. How will the Company manage coordination among the PIE supplier, Ep+C, OE, and the internal project team?

A34. The Company will manage coordination through defined scopes of work, contract requirements, project governance, interface management, schedule integration, and regular coordination among DTE Electric, Burns & McDonnell, GEV, Black & Veatch, and Barton Malow. The Company's Project Management Office will retain overall responsibility for project oversight and will use its OE and internal subject matter experts to support technical review, schedule coordination, risk management, and issue resolution.

The Company will also maintain integrated project schedules and project controls across the major contracting scopes to coordinate engineering, procurement, equipment delivery, construction, commissioning, and other execution activities.

Q35. Have any contracts described above been executed?

A35. Yes. DTE Electric has executed contracts for the UATs, and HVBs required for both the Livingston County and Monroe County projects.

Q36. Why has the Company advanced contracting activities prior to the IRP filing?

A36. Certain major equipment and project execution activities must be advanced well before commercial operation because of equipment manufacturing lead times and the sequencing of engineering, procurement, equipment delivery, construction, and commissioning activities.

The Company therefore advanced certain major equipment procurements and contracting activities prior to the IRP filing to preserve the execution schedules necessary to achieve commercial operation of the Livingston County project by the end of 2031 and the Monroe County project by the end of 2032.

Delaying these activities until the completion of the regulatory proceedings would create additional schedule risk, including the potential loss of manufacturing slots, delays in engineering and equipment delivery, and constraints on contractor and workforce availability.

Advancing these activities allows the Company to maintain the Projects' planned execution schedules while continuing to develop and finalize the remaining project scopes.

Q37. What amount of Michigan-based spend for materials does the Company expect for the Projects?

A37. The Company estimates a Michigan material spend percentage of <5% for its project. Although Michigan material spend will be limited due to current manufacturing locations for major equipment parts required for a combined cycle power plant, the Company continues to leverage local relationships to secure local materials wherever possible.

The Company has invested nearly $24 billion with Michigan-based vendors since 2010, creating and sustaining 92,000 Michigan jobs. DTE Electric invests five times more with local business than it did a decade ago. The Company recognizes the importance of supporting and involving the local economy to not only achieve project acceptance from the community, but also to boost the local economy. The Company is also closely monitoring any impacts to our projects from the ongoing tariff challenges that impact the global marketplace, including consulting with external legal counsel and industry experts as needed.

Part III: Contingency and Governance

Q38. How does the Company identify, track, and manage project execution risk?

A38. Project risk registers identify and track project risks that could affect cost, schedule, permitting, procurement, construction, or execution. Contingency reflects the

estimated capital exposure associated with identified risks that cannot yet be fully resolved or priced with certainty at this stage of project development. As the Projects mature, the Company expects the risk registers and associated cost estimates to be refined based on engineering progress, contract development, permitting status, and construction planning.

Q39. What project controls is the Company putting in place to manage risk and control cost and quality?

A39. The Company is implementing a comprehensive project controls framework to manage project scope, cost, schedule, quality, and risk throughout project execution. The framework includes a defined project baseline, formal change control procedures, project risk registers, cost and schedule monitoring, forecasting, and regular management reporting. Any proposed change affecting project scope, cost, schedule, key milestones, or contractual commitments will be subject to review, documentation, and approval through established governance processes. All approved changes will be tracked within the project management information system. The project will also utilize dedicated project controls personnel responsible for cost engineering, scheduling, forecasting, risk monitoring, reporting, and change management activities. Collectively, these controls provide visibility into project performance, support informed decision-making, and help ensure the project is delivered safely, with the required quality, and in a cost-effective manner.

Q40. Do the total cost estimates of the Livingston County and Monroe County projects include contingency?

A40. Yes. The total capital cost estimates for both Projects include contingency associated with identified project execution risks that remain subject to uncertainty at the current stage of development. I discuss the project-specific contingency amounts and the methodology used to determine below.

Q41. Why is it reasonable for projects at this stage of development to include contingency in their cost estimates?

A41. Including contingency in the cost estimates for the Projects appropriately recognizes execution risks that have been identified but cannot yet be fully resolved, mitigated, transferred, or priced with certainty.

These are large, complex generation projects with significant engineering, procurement, construction, permitting, labor, logistics, and schedule requirements. Projects of this scale and duration involve risks that remain subject to uncertainty at this stage of development, including risks that may be beyond the reasonable control of DTE Electric.

Contingency is not an arbitrary allowance or a substitute for disciplined cost management. Rather, it is a controlled project allowance developed to recognize and quantify risks identified through the project development process, including the project risk register, project execution planning, contractor input, market conditions, and lessons learned from comparable major generation projects. Examples include design development, labor productivity, material and equipment

pricing, supply chain constraints, permitting and licensing requirements, heavy haul logistics, site conditions, weather, and the coordination of multiple major contractors and suppliers.

Q42. What would be the effect of not considering contingency at this stage of project development and cost estimation?

A42. Including contingency at this stage supports a more realistic and transparent estimate for customers and the Commission. Without a risk-based allowance, the estimate would not reflect identified project risks that remain unresolved as engineering, contracting, permitting, and construction planning continue.

Recognizing these risks in the estimate provides a more complete view of the potential capital exposure associated with executing the Projects, while maintaining appropriate governance over how those funds are used.

Q43. How does the inclusion of contingency in cost estimates align with the Company's contracting strategy?

A43. The progressive Ep+C contracting approach is designed to improve cost transparency as engineering, procurement, and construction planning mature and to reduce unnecessary risk premiums that would otherwise be embedded in an early fixed-price contract. However, even with that approach, the Company retains certain owner, project execution, and market risks that must be accounted for in the total project cost estimates. The current project cost estimates include a contingency line item of [redacted], which is reasonable for projects of this nature and stage of development.

The project-specific risk registers and associated risk analysis provide a means to identify and quantify those retained risks rather than relying solely on contractor risk premiums or assuming that such risks will not materialize, or addressing them only after they affect the Projects.

As the Projects mature, identified risks may be mitigated, retired, transferred through contractual agreements, or refined based on additional information. The risk registers and associated contingency can therefore be updated as the Projects and their risk allocation evolve. This approach allows the Company to manage risk in a deliberate and transparent manner.

Q44. Do other utilities developing similar CCGT projects include contingency in their project cost estimates?

A44. Yes. Other utilities developing similar CCGT projects have included contingency in their project cost estimates. Recent filings by Indiana Michigan Power Company[1], Entergy Louisiana LLC[2], Union Electric Company (Ameren Missouri)[3], and Consumers Energy[4] show that this is a common project management practice for large generation projects. These allowances help account for identified project risks and provide regulators with a more complete estimate of expected project costs.

Part IV: Workforce and Labor Requirements

Q45. Which parties will be involved in the development and execution of the Projects?

[1] Case No. 46443, Indiana Utility Regulatory Commission
[2] Docket No. U-37882, Louisiana Public Service Commission
[3] File No. EA-2026-0226, Missouri Public Service Commission
[4] Docket No. U-22127, Michigan Public Service Commission

Line No.

A45. The development and execution of both Projects will be supported by DTE Electric, Burns & McDonnell, GEV, Black & Veatch, and Barton Malow, as well as other potential parties to be identified as the Projects continue through development. DTE Electric's Project Management Office organization will oversee and manage both Projects in their entirety. Additional resources from DTE Electric's Energy Supply, Environmental Management and Safety, and Distribution Operations organizations will participate in finalizing scopes, environmental permitting, and commissioning of the Projects. Burns & McDonnell will participate as DTE Electric's OE for the projects, augmenting Company staff as needed. As the selected OEM for the PIE on both projects, GEV will provide staff to guide installation and commissioning of the PIEs. Black & Veatch and Barton Malow will be responsible for engineering, project management support, construction, and commissioning of the Projects.

Q46. How does the Company plan to manage workforce availability and labor execution risk?

A46. The Company plans to manage workforce availability and labor execution risk through early coordination with Barton Malow, Black & Veatch, Michigan Building Trades leadership, and other project participants. The Company will continue to monitor labor availability, craft sequencing, construction schedule needs, and potential peak workforce constraints as the Projects advance. This planning is intended to support safe and efficient construction while reducing the likelihood of labor-related schedule delays.

Q47. What is the estimated workforce needed to construct the Projects?

A47. The total estimated craft labor workforce employed by Barton Malow for constructing the Projects in Livingston County and Monroe County is expected to involve in excess of three (3) million work hours for the Livingston County project and in excess of one (1) million work hours for the Monroe County project, with the demand for craft specialties shifting over the duration of the Projects. Based upon a typical project schedule, the simultaneous craft labor workforce is expected to peak at the Livingston County project site at around 850 full time equivalent (FTE) personnel, and 400 FTEs at peak for the Monroe County project site, each roughly nineteen (19) months after the start of construction. In addition to craft labor, Black & Veatch and Barton Malow on-site construction and management staff are estimated to include an additional 60 FTEs to support each of the Projects. The construction labor curve for Livingston County project is included as Exhibit A-17 and Monroe County project is included as Exhibit A-17.4.

Q48. What is the basis for this workforce estimate?

A48. The estimate of total craft labor man-hours was developed based upon Burns & McDonnell's in-house data and experience. A construction manpower curve was developed by allocating the total craft man-hours over forty-nine (49) months of expected scheduled activities using a representative man-hour curve from comparable projects. The final workforce estimate is being developed by Barton Malow.

Line No.

Q49. Will the construction craft workforce be comprised of Michigan residents in accordance with MCL 460.6t (8)(b)?

A49. The Company routinely holds discussions with the Michigan Building Trades and based on those discussions, the Company believes that adequate craft labor resources exist within the state to perform the majority of the construction work. The Company has an established relationship with the Michigan Building Trades leadership through a quarterly Tripartite meeting reviewing both near and long range planned work and trades availability. The contract currently being negotiated will require Barton Malow, to the extent practicable, to construct the Projects using Michigan workforce. The Company estimates that more than 90% of the construction craft labor will be comprised of Michigan residents who are members of the various labor unions listed below:

- Boilermakers Local 169
- Bricklayers Local 1
- Carpenters Local 687
- Cement Masons Local 514
- Electrical Workers Local 58
- Elevator Constructors Local 36
- Glaziers Local 357
- Ironworkers Local 25
- Laborers Local 1075
- Millwrights Local 1102
- Operating Engineers Local 324
- Painters District Council 1M
- Pipefitters Local 636

- Plumbers Local 98
- Roofers Local 149
- Sheet Metal Workers Locals 80 and 292
- Sprinkler Fitters Local 704
- Teamsters Locals 247 and 337

It is also recognized that the building trades rely on their national affiliates to supplement resource requirements through the defined and accepted practice of allowing "travelers" to augment their membership roles for skilled labor requirements.

Q50. Will the construction craft workforce meet all applicable labor standards per MCL 460.6t(8)(c)?

A50. Yes. The Company plans to coordinate with its engineering, construction, and labor support organizations to comply with all applicable labor standards per MCL 460.6t(8)(c), including a prevailing wage, an apprenticeship program, and either a project labor agreement or collective bargaining agreement.

Q51. What is the estimated percentage of the construction workforce that will be comprised of Michigan residents?

A51. It is anticipated that a majority of the construction workforce will be comprised of Michigan residents. Additional labor studies will be conducted as groundbreaking and the labor force mobilization get closer.

Part V: Decommissioning

Q52. Has the Company evaluated the process for decommissioning of the Projects?

A52. Yes. The Company has successfully applied its process in the decommissioning of four retired power plants over the last 15 years. The process can adapt to the specific project. For Marysville and Harbor Beach power plants, the sites were each sold to a contractor who then executed the full scope of work to return the site to a brownfield. At Conners Creek and Trenton Channel power plants, the Company managed the scope with a contractor executing the work. These projects were also successfully completed with the land returned to a brownfield. The process to decommission a project includes various requirements with local, state, and federal regulations. The Company will adapt to any existing requirements at the time the decommissioning commences.

Q53. Has the Company evaluated the cost of decommissioning of the Projects?

A53. Yes. Burns & McDonnell completed a study on the decommissioning of both the Livingston County and Monroe County projects. Based on the study, initial estimates to return each site to a near greenfield condition suitable for reuse for redevelopment are shown in Table 2. Note: All dollars shown are in 2026$.

Table 2 Estimated Decommissioning Costs

Project Site	Total Cost	Total Credits	Total Net Cost
Livingston County	$40,004,000	$(14,645,000)	$25,359,000
Monroe County	$22,893,000	$(7,674,000)	$15,219,000

Q54. Has the Company evaluated potential disposal and recycling options for the decommissioning of the Projects?

A54. Yes. As part of the decommissioning process, the Company evaluates opportunities to recycle or reuse materials where practicable to reduce disposal quantities, lower overall project cost, and minimize landfill use. Materials commonly recycled or reused during power plant decommissioning include structural steel, copper, aluminum, concrete, asphalt, piping, tanks, electrical equipment, transformers, turbines, generators, pumps, motors, ductwork, and other ferrous and nonferrous metals. Concrete and asphalt may also be crushed and reused as aggregate, road base, backfill, or other suitable site material, subject to applicable environmental requirements and project-specific conditions.

SECTION 2 – LIVINGSTON COUNTY PROJECT

Part I: Risk Register

Q55. Does the Livingston County project have a defined risk register?

A55. Yes, it does. See Exhibit A-17.2.

Q56. What amount of contingency is included in the Livingston County project cost estimate?

A56. The amount of contingency included in the Livingston County project cost estimate is $[redacted].

Q57. How was the contingency estimate for the Livingston County project determined?

A57. The Company developed a project-specific risk register identifying risks that could affect project cost. For each risk, the Company estimated the likelihood of

Line No.

occurrence and potential cost impact based on information available at the time. Those inputs were evaluated collectively through a Monte Carlo simulation to produce a range of potential project cost outcomes. The selected contingency was informed by that analysis and reflects uncertainty associated with identified project risks that remain unresolved at this stage of development. [redacted].

The risk register is used as an active project management tool and will be updated as engineering, permitting, procurement, and construction planning progress.

Q58. What types of risk are reflected in the project risk register?

A58. The project risk register reflects a range of engineering, procurement, construction, market, permitting, commissioning, and schedule-related risks identified through project development, execution planning, contractor engagement, and review of lessons learned from comparable projects.

Q59. What contractual guarantees are included in the GEV agreement?

A59. GEV is required to meet performance guarantees for the electrical output and heat rate of the PIE scope, in both the duct fired and non-duct fired conditions. They are also required to meet emission guarantees, which are measured at the stack exit of each HRSG along with near-field noise and operability guarantees.

Q60. What contractual guarantees is the Company seeking from Black & Veatch?

A60. Contractual guarantees from Black & Veatch are currently being negotiated. The Company is seeking guarantees intended to protect the plant's net output, heat rate, schedule, and provide a warranty on the engineer's design and commissioning activities.

Q61. What contractual guarantees is the Company seeking from Barton Malow?

A61. Contractual guarantees from Barton Malow are currently being negotiated. The Company is seeking guarantees intended to protect the plant's net output, heat rate, schedule, and provide a warranty on the constructor's scope of work.

Part II: Project Schedule

Q62. Is there a project schedule available for the Livingston County project?

A62. Yes. See Exhibit A-17.1.

Q63. What are the proposed milestones for the Livingston County project?

A63. As described by Witness Pratt, the Proposed Course of Action (PCA) contained within this proceeding identifies that the Livingston County project will have a COD in 2031. Compliance requirements prescribed by the Midcontinent Independent System Operator (MISO), including a Generator Verification Test Capacity, must be completed by the end of August each year to be included in the planning cycle for available energy. To achieve these dates, construction is planned to begin at the end of 2027. The Company estimates that, from full notice to proceed, the project will require approximately forty-eight (48) months to engineer, procure, and construct. In addition, the approval process and limited notice to

proceed with engineering will precede construction by twenty (20) months. All permitting, contracts and authorizations, including Certificates of Necessity (CON) approval are precedent activities to start construction.

The project will also have three interim major milestones for Engineering Completion, Mechanical Completion, and Substantial Completion. These milestones are tied to EPC scope with Black & Veatch and Barton Malow and are currently being negotiated.

The PIE scope will have interim major milestones for GEV as well. Those are in the process of being negotiated but currently includes major equipment EX Works dates of June 30, 2028 for gas turbine #1, August 31, 2028, for gas turbine #2, July 31, 2028, for generator #1, and September 30, 2028, for generator #2. EX Works is the date that the shipper, in this case GEV, will have their equipment ready for delivery from their factory.

Part III: Permit Development for Construction and Operation

Q64. What permits are required by the Michigan Department of Environment, Great Lakes, and Energy (EGLE) for the Livingston County project?

A64. Witness Marietta discusses the details regarding environmental permits required to construct the Projects in his direct testimony.

Q65. What other permits are required for construction to commence the Livingston County project?

A65. The permits required to commence construction are shown in the permit matrix in Exhibit A-17.3.

Q66. How will the Company coordinate permitting requirements with the project schedule?

A66. A detailed and integrated schedule will be developed for the project that includes all permitting requirements, expected time for development, submittal, review, and approval to ensure that work proceeds on schedule.

Part IV: Infrastructure Upgrades

Q67. Are there any infrastructure upgrades required to execute the Livingston County project?

A67. Yes. Adjacent roadway upgrades are required for the Livingston County project. Witness Swiech discusses gas pipeline infrastructure upgrades in his testimony.

Q68. Can you elaborate on the adjacent roadway upgrades required for the Livingston County project?

A68. Yes. It is likely that roads directly adjacent to the project site will need to be enhanced to allow efficient flow of traffic arriving and departing the site each day. Specific road upgrades will be identified during engineering. Any such upgrades will be discussed with and approved by the proper authorities before any work commences.

Q69. Are there upgrades required to other roadways, railways, or ports to complete the project?

A69. The delivery route for major components requiring heavy haul transport is not known and therefore there are no known required upgrades to other roadways, railways, or ports at this time. GEV, Black & Veatch, Barton Malow, and DTE Electric's owner furnished equipment suppliers will be working on their specific transportation requirements as design progresses.

SECTION 3 – MONROE COUNTY PROJECT

Part I: Risk Register

Q70. Does the Monroe County project have a defined risk register?

A70. Yes, it does. See Exhibit A-17.6.

Q71. What amount of contingency is included in the Monroe County project cost estimate?

A71. The amount of contingency included in the Monroe County project cost estimate is $[redacted].

Q72. How was the contingency estimate for the Monroe County project determined?

A72. The Company developed a project-specific risk register identifying risks that could affect project cost. For each risk, the Company estimated the likelihood of occurrence and potential cost impact based on information available at the time. Those inputs were evaluated collectively through a Monte Carlo simulation to produce a range of potential project cost outcomes. The selected contingency was informed by that analysis and reflects uncertainty associated with identified project

Line No.

risks that remain unresolved at this stage of development. [redacted]

The risk register is used as an active project management tool and will be updated as engineering, permitting, procurement, and construction planning progress.

Q73. What types of risk are reflected in the project risk register?

A73. The project risk register reflects a range of engineering, procurement, construction, market, permitting, commissioning, and schedule-related risks identified through project development, execution planning, contractor engagement, and review of lessons learned from comparable projects.

Q74. What contractual guarantees are included in the GEV agreement?

A74. GEV is required to meet performance guarantees for the electrical output and heat rate of the PIE scope, in both the duct fired and non-duct fired conditions for the Monroe County project. They are also required to meet emission guarantees, which are measured at the stack exit of each HRSG. Near-field noise and operability guarantees are also required for GEV.

Q75. What contractual guarantees is the Company seeking from Black & Veatch?

A75. The Company is seeking guarantees intended to protect the plant's net output, heat rate, schedule, and provide a warranty on the engineer's design and commissioning activities.

Q76. What contractual guarantees is the Company seeking from Barton Malow?

A76. The Company is seeking guarantees intended to protect the plant's net output, heat rate, schedule, and provide a warranty on the constructor's scope of work.

Part II: Project Schedule

Q77. Is there a project schedule available for the Monroe County project?

A77. Yes, See Exhibit A-17.5.

Q78. What are the proposed milestones for the Monroe County project?

A78. As described by Witness Pratt, the PCA contained within this proceeding identifies that the Monroe County project will have a COD in 2032 for resource adequacy needs. Compliance requirements prescribed by the Midcontinent Independent System Operator (MISO), including a Generator Verification Test Capacity, must be completed by the end of August each year to be included in the planning cycle for available energy. To achieve these dates, construction is planned to begin in the winter of 2028-2029 for Monroe. The Company estimates that, from full notice to proceed, the project will require approximately forty-eight (48) months to engineer, procure, and construct. In addition, the approval process and limited notice to proceed with engineering will precede construction by twenty (20) months. All permitting, contracts and authorizations, including CON approval are precedent activities to start construction.

Line No.

The project will also have three interim major milestones for Engineering Completion, Mechanical Completion, and Substantial Completion. These milestones are tied to EPC scope with Black & Veatch and Barton Malow and are currently being negotiated.

The PIE scope will have interim major milestones for GEV as well. Those are in the process of being negotiated but currently include major equipment EX works dates of October 31, 2030, for the gas turbine and November 30, 2030, for the generator.

Part III: Permit Development for Construction and Operation

Q79. What permits are required by EGLE for the Monroe County project?

A79. Witness Marietta discusses the details regarding environmental permits required to construct the Projects in his direct testimony.

Q80. What other permits are required for construction to commence the Monroe County project?

A80. The permits required to commence construction are shown in the permit matrix in Exhibit A-17.7.

Q81. How will the Company coordinate permitting requirements with the project schedule?

A81. A detailed and integrated schedule will be developed for the project that includes all permitting requirements, expected time for development, submittal, review, and approval to ensure that work proceeds on schedule.

Part IV Infrastructure upgrades

Q82. Are there any infrastructure upgrades required for the Monroe County project?

A82. Yes. Adjacent roadway upgrades are required for the Monroe County project. Witness Swiech discusses gas pipeline infrastructure upgrades in his testimony.

Q83. Can you elaborate on the adjacent roadway upgrades required for the Monroe County project?

A83. Yes. It is likely that roads directly adjacent to the project site will need to be enhanced to allow efficient flow of the team members and deliveries arriving and departing the site each day. The specific enhancements to the roads will be identified as engineering progresses. Any enhancements will be discussed with and approved by the proper authorities before any work commences.

Q84. Are there upgrades required to other roadways, railways, or ports to complete the project?

A84. The delivery route for major components requiring heavy haul transport is not known and therefore there are no known required upgrades to other roadways, railways, or ports at this time. GEV, Black & Veatch, Barton Malow, and DTE Electric's OFE suppliers will be working on their specific transportation requirements as design progresses.

Q85. Does this complete your direct testimony?

A85. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MATTHEW LIND

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF MATTHEW LIND

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Matthew Lind. I am employed by 1898 & Co. as a Technical Director in the Renewable & Market Advisory Business Line. My business address is 9400 Ward Parkway, Kansas City, Missouri 64114. A statement of my qualifications and experience is included in my resume attached as Exhibit A-18.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q3. What is your educational background and certifications?

A3. I have a Bachelor of Science in Industrial Engineering from Iowa State University. I also have a Master of Business Administration in Finance from the University of Missouri-Kansas City.

Q4. What is your professional experience?

A4. I have over 22 years of experience in advising clients in the electric power industry, including providing market evaluations and strategic system planning studies to target investment decisions informed by robust analytics. Throughout my professional career, I have provided evaluations and recommendations for multiple billions of dollars in generation and transmission infrastructure investment. My management experience includes projects in multiple North American markets as well as international organized markets.

In addition to assessing analytics and preparing investment planning reports for market operators and participants in the utility industry, I am qualified to support

such materials and recommendations before regulatory and adjudicative bodies. I have significant experience working with utility clients to provide regulatory compliance and consulting services on energy projects, including applications to amend certificates of necessity (CON) or their counterparts in other states.

In recent years, I have managed or advised on numerous projects involving regulated utilities throughout the country. This has included conducting a prudency review of investments, serving as an expert witness and/or consultant in applications for proposed electric utility facilities before a number of states and the Federal Energy Regulatory Commission (FERC), development of resource plans pursuant to certain regulatory requirements, and more.

Q5. What are your current duties and responsibilities?

A5. As Technical Director in the Renewables & Markets Advisory Business, I support business development for strategic clients and pursuits, marketing, staff training and project execution focused on developing economic models and analyses associated with generation and transmission planning. Our clients include municipals, cooperatives, investor-owned utilities, independent generation and transmission developers and regional transmission organizations (RTO) and independent system operators (ISO). Projects include integrated resource planning, new resource procurement administration and evaluation, economic transmission planning, demand-side management, asset retirement, transmission congestion impacts, and other financial planning decisions.

Line No.

Q6. Do you hold any professional certifications or belong to any professional organizations?

A6. I am a registered Professional Engineer in the state of Kansas. I am a member of the Edison Electric Institute (EEI), and I serve on EEI's Transmission Executive Committee, which supports the System Planning and Operations subcommittee. I was also recognized as a Public Utilities Fortnightly Under 40 in 2020.

Q7. Have you previously sponsored testimony in utility regulatory proceedings?

A7. Yes. I have submitted testimony before:

FERC	(Docket Nos. EL02-60-018, EL02-62-017, EL20-68-002)
Illinois Commerce Commission	(Docket No. 23-0061)
Indiana Utility Regulatory Commission	(Docket Nos. 44446, 44927, 45052, 45493, 45591, and 46100)
Public Utility Commission of Texas	(Docket No. 58664)
Wisconsin Public Service Commission	(Docket No. 9698-CE-100)

In addition to the above matters for which I provided testimony, I have worked on preparing and/or supporting filings in matters before FERC (Docket Nos. ER21-502-000 and ER25-596-000), the Arizona Corporation Commission (Docket No. E-01773A-12-0305), and the Minnesota Public Utility Commission (Docket Nos. E015/M/AI-17-568, E015/RP-15-690, E015/CN-12-1163, E015/RP 13-53, E015/RP 09-1088, and E017/RP-10-623). These matters involved a variety of energy topics, such as acquisitions of solar and storage facilities, applications for

new electric transmission and generation facilities, petitions for new wind, solar, and natural gas resources, estimating the capital cost of various power generating technologies and comparison of public cost data, and reviews of rates.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. My testimony supports DTE Electric's application request for CONs to construct and operate the proposed Livingston County and Monroe County combined-cycle gas turbine (CCGT) generating facilities. Specifically, my testimony describes the development of the cost estimate associated with the engineering, procurement, and construction (EPC) Cost portion of the overall project cost and compares the projects' estimated costs to recent utility-sponsored projects around the country. Where appropriate, the projects' costs are adjusted to facilitate consistent comparison and demonstrate the proposed projects' estimated costs fall within the range of reasonableness when fairly compared to similar projects, considering current market conditions.

Q9. Are you sponsoring any exhibits in the proceeding?

A9. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-18	Resume of Matthew Lind
A-18.1	CCGT Cost Comparison Table

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Line No.

Q11. How is your testimony organized?

A11. My testimony is organized in the following parts:

Part I: Overview of CCGT Cost Comparison Analysis

Part II: Power Generation Technology EPC Cost Estimates

Part I: Overview of CCGT Cost Comparison Analysis

Q12. Please provide an overview of the Proposed Projects discussed in this proceeding.

A12. The Proposed Livingston County Project is configured as an approximately 1,400 MW nameplate-capacity combined-cycle power plant, consisting of two (2) combustion turbine generators (CTGs), two (2) heat recovery steam generators (HRSGs), and two (2) steam turbine generators (STGs), each operating in a 1x1 configuration. The Proposed Monroe County Project is configured as an approximately 700 MW nameplate-capacity combined-cycle power plant, consisting of a single CTG, HRSG, and STG operating in a 1x1 configuration. Both projects will use advanced class natural gas combustion turbine technology. For more information associated with specific project details, please refer to Witness Stansell's testimony.

Q13. At a high level, please describe how you analyzed and compared the cost estimates provided by DTE Electric against other CCGT projects.

A13. I took three steps in making a comparison of the DTE Electric Proposed Projects to other CCGT projects. The first step was to gather external project-specific cost data for CCGT projects with commercial operation dates (COD) reasonably comparable to DTE Electric's CCGT projects and of similar technology and configuration. The

gathered datasets were grouped into CCGT projects of comparable output size, or MW, to either Livingston County or Monroe County.

The next step was to adjust from the total construction cost of each project as necessary to make a more reasonable direct comparison to either the Livingston County or Monroe County project. The types of adjustments included removing allowance for funds used during construction (AFUDC) and normalizing against DTE Electric project location, CCGT equipment configuration, and cost estimate timing. Project costs were compared on both a total project cost basis and a dollars-per-kilowatt ($/kW) basis, where total project cost was divided by the project's nameplate capacity.

The final step was to summarize the adjusted cost information from each project into a comparison table. This comparison table, together with a summary of the data sources used to compile it, can be found in the attached Exhibit A-18.1.

Q14. How did you arrive at the list of CCGT projects on the comparison table?

A14. Utility-sponsored CCGT projects under development or construction were identified through publicly available regulatory filings and other project documentation. Other public information that was not associated with a specific project, such as the U.S. Department of Energy's Energy Information Administration's (EIA) Annual Energy Outlook (AEO) capital costs, was not compared. The comparison table includes projects for which publicly available cost information was available to support a comparison to DTE Electric's projects.

Q15. As you gathered the CCGT project comparison dataset, were there any noticeable trends in the costs?

A15. Yes. Before making project-specific adjustments, the dataset shows a general trend of higher reported project costs for CCGT projects with later in service dates.

Q16. What factors increase the cost for projects with CODs beyond 2030?

A16. I believe an important contributor to the increase in project costs over time is the current imbalance between demand for natural gas turbines and related construction services and available supply of manufacturing and construction capacity. There are multiple factors driving an increasing demand for new natural gas-fired generation facilities. These factors include clean energy standards, retirement of aging coal-fired generation, resource adequacy policy, onshoring of manufacturing and industrial processes, and large load growth in the United States and globally, such as that stemming from data center developments. This surge in demand is straining labor markets and the supply chains for equipment associated with these facilities. The current production capacity of gas turbines is such that parties interested in reserving a production slot currently must wait more than five years to receive their turbine order[1]. This demand relative to supply is creating upward pressure on pricing in a way that is more volatile than typical inflation.

Q17. What project-specific factors should be considered when comparing public sources of estimated CCGT project costs?

A17. Beyond simply comparing similar generation technologies (e.g., gas-fired combined cycle, etc.) and MW output scale, several project-specific characteristics

[1] GE Vernova 2Q 2026 Results & Outlook; https://www.gevernova.com/sites/default/files/gev_webcast_transcript_07222026.pdf,

can affect the estimated cost of a CCGT project and should be considered when comparing projects. Key characteristics of CCGT projects include turbine configuration, site conditions (e.g., greenfield or brownfield), gas and electric interconnection requirements, cooling system design, geographic location and building enclosure requirements, local labor conditions, project schedule, construction equipment costs, market timing and other market conditions. It is important to note that not all these characteristics can be reliably adjusted to make similar comparisons because the necessary project-specific information is not consistently available.

Q18. What project-specific factors did you include adjustments in your comparison of CCGT projects?

A18. I made specific adjustments related to AFUDC, configuration, location, and project timing.

Q19. What adjustments were made related to AFUDC?

A19. Utilities and developers have different project-specific financing structures and costs, and utility project cost estimates may differ in whether and how financing costs incurred during construction are reflected. Therefore, it was preferred to compare project costs without AFUDC. As shown in Exhibit A-18.1, the comparison table identifies whether AFUDC was included, excluded, or unknown for each project.

For projects where AFUDC was either excluded or its inclusion could not be determined, no adjustment to the publicly reported total project cost was made.

For projects where AFUDC was included, it was removed based on the amount specified. If no specific amount was specified as AFUDC, a simplified factor was applied to the cited total project cost based on an assumed project capital structure, construction and expenditure schedule from EIA and the National Energy Technology Laboratory (NETL) in order to approximate an AFUDC amount.

Q20. What adjustments were made related to configuration?

A20. In comparing CCGT projects, if the configuration of CTG, HRSG and STG was not similar, an adjustment was made to account for project scale in order to reflect a similar configuration as the comparable DTE Electric project. For example, in comparing the Anderson County CCGT project to the Livingston County project, the Anderson County project is configured as a 2x1 CCGT whereas the Livingston County project is configured as two 1x1 CCGTs. To make configuration adjustments, public information on cost estimates from IRP planning proceedings were used to understand the differences between 2x1, 2-1x1, and 3-1x1 CCGT projects.

Q21. What adjustments were made related to project location?

A21. Every other CCGT project referenced for comparison to DTE Electric's CCGT projects was located in a different state. Geographic location can result in differences in labor, material, and construction costs. To normalize these geographical cost differences, I used the location adjustment factors (LAF) published in the January 2024 EIA-commissioned Sargent & Lundy capital cost study. I used the closest city within the same state as the project location to determine the LAF for each project. I then normalized each CCGT project's cost

estimate to be compared to the DTE Electric project as if both cost estimates were based on the location of Detroit, MI rather than the city and state LAF that the project is located in. It is important to note that this location adjustment does not account for other differences in project scope, such as building enclosures or cooling design, which may also be driven by location.

Q22. What adjustments were made related to project timing?

A22. Two different adjustments were made relative to project timing. The first adjustment was inflation to account for project cost estimates that were provided in different years. The Engineering News-Record (ENR) construction cost index (CCI) was used as a proxy for the inflation rate associated with constructing a new CCGT generation facility. The average inflation from the last 5 calendar years of the CCI was used to develop an average annual inflation rate of approximately 4 percent. This average annual inflation rate was used to adjust project cost estimates that were provided in years different from the 2026 dollar basis of the DTE Electric CCGT projects.

Q23. What other adjustment was made related to project timing?

A23. The second adjustment I made relative to project timing was related to the current market dynamics associated with natural gas turbines and related installation activity. Based on the market demand and supply factors I discussed previously, I made an additional adjustment based on project timing reflecting cost escalation beyond typical inflation.

In order to account for this, I have used a commodity-specific producer price index ("PPI") for turbines and generator sets from the U.S. Bureau of Labor Statistics. The average escalation from the last 5 calendar years of this commodity-specific PPI was used to develop an equipment market escalation adjustment of approximately 4.3 percent. Each project was adjusted to normalize the COD timing to the same as that of the comparable DTE Electric CCGT project.

Q24. After making these adjustments, can all the projects be fairly compared to one another?

A24. The adjustments provide a general normalizing of major cost categories and allow for a better direct comparison of estimated project costs. However, other considerations that I previously mentioned were not factored into the adjustments due to limited information. These included things like normalizing against site conditions (e.g., greenfield or brownfield site), owner's cost, plant cooling system, building enclosures, gas pipeline and electric interconnection costs, and other market-specific factors. These considerations could increase or decrease the costs further. Accordingly, I do not consider the adjusted costs to represent precise like-for-like estimates. Rather, the adjustments as detailed in Exhibit A-18.1 provide a reasonable normalization of the available project cost information for purposes of evaluating the relative reasonableness of DTE Electric's estimated project costs.

Q25. Please provide a brief summary of the CCGT projects and adjusted total cost estimate relative to the Livingston County CCGT project.

A25. Exhibit A-18.1 includes a comparison of the CCGT projects evaluated relative to the Livingston County CCGT project. The table below summarizes the key project characteristics and adjusted total cost estimates for those projects.

Table 1 Livingston County CCGT Project Comparison

Resource Name	Canadys Station	Cayuga Energy Complex	Bison Generation Station	Anderson County Energy Center	Smarr Energy Facility	Livingston County
Utility Name	Santee Cooper & Dominion Energy South Carolina	Duke Energy	Basin Electric Power Cooperative	Duke Energy Carolinas	Oglethorpe Power Corporation	DTE Electric
Nameplate Capacity (MW)	2,180	1,476	1,490	1,365	1,425	1,400
Configuration	3x (1x1)	2x (1x1)	2x (1x1)	2x1	2x (1x1)	2x (1x1)
Location	Colleton County, SC	Cayuga, IN	Williams County, ND	Anderson County, SC	Monroe County, GA	Livingston County, MI
Commercial Operation Date	6/1/2033	Unit 1: 2029 Unit 2: 2030	Unit 1: 2029 Unit 2: 2030	2031	2029	2031
Adjusted Total Cost (2026$M)	$ 5,833	$ 3,774	$ 4,000	$ 4,280	$ 3,518	$ 3,925
Adjusted Cost per kW (2026$/kW)	$2,676	$2,557	$2,684	$3,135	$2,469	$2,804

Q26. What does your comparison table indicate regarding the estimated cost of the Livingston County Project?

A26. Following the adjustments described previously, the comparable CCGT projects range from approximately $2,500/kW to $3,100/kW on a normalized basis. The estimated cost of the Livingston County Project is approximately $2,804/kW and falls within the range of costs represented by these recently proposed or developing CCGT projects.

In my opinion, this comparison provides market-based support that the estimated cost of the Livingston County Project is reasonable relative to the costs currently

being experienced by other utility-sponsored CCGT projects of generally comparable size and timing.

Q27. Please provide a brief summary of the CCGT projects and adjusted total cost estimate relative to the Monroe County CCGT project.

A27. Exhibit A-18.1 includes a comparison of the CCGT projects evaluated relative to the Monroe County CCGT project. The table below summarizes the key project characteristics and adjusted total cost estimates for those projects.

Table 2 Monroe County CCGT Project Comparison

Resource Name	Chisholm Trail Energy Center	McNew Generating Station	Monroe County
Utility Name	Evergy	Evergy	DTE Electric
Nameplate Capacity (MW)	710	710	700
Configuration	1x1	1x1	1x1
Location	Sumner County, KS	Reno County, KS	Monroe County, MI
Commercial Operation Date	1/1/2029	1/1/2030	2032
Adjusted Total Cost (2026$M)	$ 2,225	$ 2,169	$ 2,518
Adjusted Cost per kW (2026$/kW)	$3,134	$3,055	$3,597

Q28. Are there any limitations associated with the Monroe County benchmark dataset that should be considered?

A28. Yes. Unlike the Livingston County comparison, which includes five benchmark projects, I identified only two publicly available utility-sponsored CCGT projects of generally comparable size and configuration to the Monroe County Project. As a result, the Monroe County comparison is based on a more limited set of benchmark data and individual project-specific factors such as cooling design, site

conditions and building enclosure design may have a greater influence on the adjusted cost comparison.

Q29. What does your comparison table indicate regarding the estimated cost of the Monroe County Project?

A29. Following the adjustments described previously, the comparable CCGT projects are approximately $3,100/kW on a normalized basis. The estimated cost of the Monroe County Project is approximately $3,597/kW, representing a variance of approximately 15% relative to the two available project benchmarks.

In my opinion, this comparison provides market-based support that the estimated cost of the Monroe County Project is reasonable relative to the costs currently being experienced by other utility-sponsored CCGT projects of generally comparable size and timing.

Part II: Power Generation Technology EPC Cost Estimates

Q30. Please provide an overview of the components resulting in the total cost estimate for the Proposed Projects.

A30. The total cost estimate at each project location was developed from three distinct components – the cost of major equipment items including CTG, HRSG, and STG (Power Island Equipment Cost), the cost of site development, installation and construction through an EPC contractor (EPC Cost), and owner's cost for owner's project management, engineering services and other related costs (Owner's Cost).

Q31. Please describe your understanding of Burns & McDonnell's role in developing the EPC Cost estimates associated with the Proposed Projects.

A31. Burns & McDonnell was retained by DTE Electric as an Owner's Engineer in order to develop project-specific cost estimates for the EPC costs associated with new

combined-cycle, gas fired generation facilities. Burns & McDonnell initially provided cost estimates in the fall of 2025 and revised the estimates in 2026 to reflect updated labor and escalation assumptions.

Q32. Were you directly involved in this activity?

A32. No. My role in this case is to provide an overview of the cost estimating methodology and accuracy range, as well as provide third-party benchmarking data for comparison.

Q33. Describe the cost estimating methodology used by Burns & McDonnell for the Livingston County project.

A33. Burns & McDonnell developed an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimate for DTE Electric's Livingston County project. Consistent with the preliminary level of project definition associated with a Class 4 estimate, as shown in Witness Stansell's Confidential Exhibit A-16, Burns & McDonnell performed engineering to develop the project on a site-specific basis, establishing material quantities, equipment requirements, construction considerations, and other inputs to support the cost estimate.

The engineering activities included development of a site-specific plant arrangement including evaluation of site civil and grading requirements, development of piping and instrumentation diagrams, creation of single-line electrical drawings, and a project construction schedule. These activities provided the engineering basis for the cost estimate.

Burns & McDonnell also provided estimate development activities that increased the amount of project-specific information incorporated into the estimate. These activities included development of material quantities and solicitation of vendor pricing for selected equipment, including specialty pumps, the air-cooled condenser and heat exchanger, auxiliary boiler, and fuel gas compressors. Incorporating project-specific quantities and vendor pricing, where available, reduced reliance on generalized allowances or benchmark costs for these components and provided additional support for the estimated project cost.

A detailed breakdown of the cost estimate can be found in Witness Stansell's Confidential Exhibit A-16.

Q34. Describe the cost estimating methodology used by Burns & McDonnell for the Monroe County project.

A34. The cost estimate for Monroe County was developed for a single 1x1 CCGT configuration using the Livingston County estimate as its underlying basis, with adjustments to reflect differences associated with the smaller configuration. As shown in Witness Stansell's Confidential Exhibit A-16.1, Burns & McDonnell adjusted the estimate by removing all equipment and scope exclusively associated with the second combined-cycle train, scaling common systems from a two-train to one-train configuration and reflecting a project-specific schedule with a commercial operations date of Q3/Q4 2032. A detailed breakdown of the cost estimate can be found in Witness Stansell's Confidential Exhibit A-16.1.

Q35. In your experience, what are different cost estimate methodologies used for IRP input cost estimates?

A35. I have overseen IRP projects that use a range of methodologies and sources to develop capital cost assumptions for new generation resources. These range from publicly available reference costs, such as those published as part of EIA's AEO, to project-specific engineering cost estimates.

Public references can provide reasonable planning-level assumptions but generally represent generic or representative projects and broad regional conditions. Project-specific engineering estimates can incorporate greater levels of project definition, including site-specific conditions, equipment requirements, construction considerations, current market information, and other characteristics of the resource being evaluated. As a result, these estimates can provide a more project-specific basis for establishing capital cost assumptions.

Q36. How does the cost estimating methodology used by DTE Electric compare to methodologies you have observed in other IRPs?

A36. In my experience, a site-specific AACE Class 4 estimate supported by engineering development, material quantity estimates, a construction schedule, and vendor pricing is toward the more rigorous end of the cost estimating approaches typically used to establish IRP capital cost assumptions. The level of project-specific development incorporated into the Livingston County estimate provided a robust basis for representing the expected cost of that resource in DTE Electric's resource planning analysis.

CONCLUSION

Q37. Please summarize your analyses and recommendations regarding the reasonableness of costs presented for the CCGT projects discussed in your direct testimony.

A37. Based on my review, I find the estimated costs of the Monroe County and Livingston County CCGT Projects to be reasonable. This conclusion is supported by two primary considerations.

First, the cost estimates are based on a substantial level of project-specific engineering and cost development. The Livingston County estimate was developed as an AACE Class 4 estimate supported by site-specific engineering, material quantity estimates, construction scheduling, and vendor pricing for select equipment. In my experience, this represents a robust level of cost development for a project evaluated through the resource planning process.

Second, I compared the Proposed Projects' estimated costs to recently proposed or developing utility-sponsored CCGT projects and normalized those costs, where appropriate, for differences in AFUDC, configuration, location, and project timing. Following these adjustments, the estimated costs of the Proposed Projects are within a reasonable range of the comparable project cost information.

Taken together, the project-specific basis underlying the cost estimates and the external market benchmarking provide reasonable support for the estimated costs of the Proposed Projects.

Q38. Does this conclude your pre-filed direct testimony?

A38. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PRIYA MACHI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF PRIYA MACHI

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Priya Machi (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy), as Manager, Regulatory Affairs.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Science in Engineering with a specialty in Chemical Engineering in 2012, and a Master of Engineering in Energy Systems Engineering in 2015, both from the University of Michigan, Ann Arbor.

Q4. What is your professional experience?

A4. I was employed by Consumers Energy from 2012 until 2022, initially as an Engineer and ultimately being promoted to Principal Strategy Analyst. I held various roles at Consumers Energy including, but not limited to, leading the Integrated Resource Planning modeling team and supporting energy policy on various state and federal governmental, regulatory and energy market issues. In July 2022, I joined General Motors as Business Development Manager, where I was responsible for working with utilities nationally on the development of EV vehicle-grid integration and stationary storage programs. In May 2025, I joined DTE Energy in my current role as Manager, Regulatory Affairs.

Line No.

Q5. What are your current duties and responsibilities?

A5. My responsibilities include the management of regulatory activities relating to DTE Electric's rate strategy, pricing, and load research.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission?

A6. Yes. I sponsored testimony in the following Michigan Public Service Commission (MPSC or Commission) cases:

U-18090	Consumers Energy's proceeding associated with the Public Utility Regulatory Policies Act of 1978
U-20963	Consumers Energy's 2021 Electric Rate Case
U-22046	DTE Electric's 2026 Electric Rate Case
U-22109	DTE Electric's 2026 Securitization Case

PURPOSE OF TESTIMONY

Q7. What is the purpose of your testimony?

A7. My testimony presents the average rate impacts by customer class and residential energy burden calculation associated with the Proposed Course of Action (PCA). Witness Hajj provides an overview of the PCA, and Witness Manning describes the PCA and sponsors the modeled revenue requirement results used in my analyses. My analyses address the MPSC's December 18, 2025 Order in Case Nos. U-21867 and U-21570 (Exhibit B, pages 30-31) and Section 6t(5)(k) of 2023 PA 231, MCL 460.6t(5)(k), and the applicable directives in the Commission's December 18, 2025 Order in Case No. U-21990. Specifically, my testimony includes:

- An analysis of average rate impacts for the residential, commercial, industrial, and other customer classes consistent with the methodology that the Company used in Case No. U-21193, the Company's 2022 Integrated Resource Plan (IRP).
- An analysis of the residential energy burden by income level, consistent with the filing requirements in Case Nos. U-21867 and U-21570.
- An analysis of the average rate impact by customer class and residential energy burden for the PCA both with and without the load and cost impacts from Oracle America Cloud Services (OACS), per the Commission's December 18, 2025 Order in Case No. U-21990.
- An analysis of the average rate impact by customer class and residential energy burden for the PCA both with and without the load and cost impacts from Google LLC (Google), as filed in Case No. U-22058.

My testimony is organized in two parts. Part I presents the Company's average rate impact analysis by customer class, and Part II presents the Company's residential energy burden analysis.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-19	Residential Rate Analysis
A-19.1	Commercial Rate Analysis
A-19.2	Industrial Rate Analysis
A-19.3	Other Rate Analysis
A-19.4	Energy Burden

Q9. Were these exhibits prepared by you or under your direction?

A9. Yes, they were.

PART I: RATE IMPACTS

Q10. Please summarize the filing requirements for IRP rate impact analyses that you are sponsoring.

A10. There are two IRP filing requirements that pertain to rate impacts. The first is summarized in Exhibit B, page 31 of the Commission's December 18, 2025 Order in Case Nos. U-21867 and U-21570, and states that the filing should include:

> *The average rate impact by customer class (i.e., residential, C&I, etc.). The analysis shall include the Utility's most recently approved base rate*

Line No.

revenue requirement for full-service customers, a forecast of the revenue requirement growth based on a projected inflation factor, the percentage of the production cost allocations assignable to each customer class, based on the prior approved rate case, and the estimated delta revenue requirement of the PCA to determine the average rate impact.

1. *The Utility shall identify the class allocation of the incremental revenue requirement, the class sales forecast and compare it to the current average rate, and class allocation of the incremental revenue requirement shown as a percentage.*
2. *This rate impact analysis should also include the impact to customers as a result of PCA resources that are cost recovered using the PA 235, Section 22 revenue recovery mechanism.*

The second filing requirement is summarized in Section IV(h) of Exhibit B, page 19 of the Commission's December 18, 2025 Order in Case Nos. U-21867 and U-21570 and states that rate impacts should be analyzed without the inclusion of any large loads (defined as those greater than 300 MW with a load factor of 80% or greater).

Similar requirements were included in the Commission's December 18, 2025 Order in Case No. U-21990[1], which requires a customer-specific comparison of resource needs with and without the inclusion of the OACS load, and the corresponding rate impacts by class and energy burden analyses. The Company also performed these analyses for the load and related changes to modeled costs associated with Google.

[1] U-21990 Order, Michigan Public Service Commission, Order, Case No. U-21990, December 18, 2025, pp. 36–37

Q11. What information is presented in Exhibit A-19?

A11. Exhibit A-19 calculates the average residential rate impacts associated with the Company's PCA, per the filing requirements above. As I discuss below, this exhibit uses various inputs sponsored by Witnesses Manning, Sirwaitis, Busse, and Bilyeu to determine the average rate impacts of the PCA and incremental impacts of the Google and OACS loads and related changes to modeled costs.

Q12. Please describe the rate impact comparisons evaluated in Exhibit A-19.

A12. Exhibit A-19 includes three average residential rate impact comparisons, consistent with the Commission's December 18, 2025 Orders in Case Nos. U-21867, U-21570 and U-21990. Witness Manning describes the modeling cases underlying the comparisons below.

- The first comparison begins on Line 1 and continues through Line 26 and is referred to as the "2026 PCA (No OACS/Google) vs. 2026 PCA (No Google)" comparison. This comparison evaluates the average incremental residential rate impact of adding the OACS load and related changes to modeled costs while continuing to exclude the Google load and modeled costs. This comparison supports the with and without OACS analysis directed by the Commission's Order in Case No. U-21990 and the Case Nos. U-21867 and U-21570 filing requirements.

- The second comparison begins on Line 29 and continues through Line 51 and is referred to as the "2026 PCA (No Google) vs. 2026 PCA" comparison. This comparison evaluates the average incremental residential

rate impact of adding the Google load and related changes to modeled costs while continuing to include the OACS load. This comparison supports the Company's corresponding with and without Google analysis associated with Case No. U-22058 and the Case Nos. U-21867 and U-21570 filing requirements.

- The third comparison begins on Line 54 and ends on Line 65 and is referred to as the "2022 PCA vs. 2026 PCA" comparison. This comparison evaluates the average residential rate impact of the Company's 2026 PCA compared with the portfolio approved in Case No. U-21193, consistent with the filing requirements established in Case Nos. U-21867 and U-21570.

Q13. Please describe how you calculated the residential rate impacts in the "2026 PCA (No OACS/Google) vs. 2026 PCA (No Google)" comparison.

A13. Exhibit A-19, Line 2 shows the Company's current base revenue requirement for residential customers, as approved by the Commission in its February 19, 2026 Order in Case No. U-21860 (DTE Electric's 2025 Electric Rate Case). Line 2 excludes revenues associated with the Power Supply Cost Recovery (PSCR) factor or securitization surcharges as those are not included in the approved Case No. U-21860 rate design model. Line 3 forecasts revenue requirement growth based on an inflation factor, and without any impacts of OACS or Google costs or loads. The inflation factor used is discussed in the testimony of Witness Busse.

Lines 5 and 6 are revenue requirements modeled for the "2026 PCA (No OACS/Google)" and "2026 PCA (No Google)" cases as supported by Witness

Line No.

Manning in Exhibit A-2.4. In addition, as renewable compliance costs are not modeled by Witness Manning, Line 8 reflects the renewable compliance costs caused by OACS, as supported by Witness Bilyeu. The percentage of production cost allocation assignable to the residential class is shown on Line 10 for the "2026 PCA (No OACS/Google)" case and on Line 11 for the "2026 PCA (No Google)" case. The production cost allocation methodology used is discussed later in my testimony. Additionally, as renewable costs are recovered volumetrically, the volumetric allocation used in the 2026 PCA (No Google) case is shown in Line 13.

Lines 15 and 16 allocate the revenue requirements as modeled by Witness Manning for the "2026 PCA (No OACS/Google)" and "2026 PCA (No Google)" cases, and the renewable compliance costs as sponsored by Witness Bilyeu, to the residential class. The residential revenue requirement projection for the "2026 PCA (No Google) case" is calculated on Line 18. Lines 20 and 21 are the residential class sales forecasts as supported by Witness Sirwaitis in Exhibit A-7.2 for the cases without and with the OACS load, respectively.

The residential rates based on the final Order in Case No. U-21860, plus the impacts of inflation and utilizing the IRP sales forecasts, are shown in Line 23, and represent a scenario with no OACS or Google costs or loads included. Lines 24 and 25 show the absolute rate impact and the relative rate impact of the addition of the OACS loads and costs, respectively. Finally, Line 26 shows the average residential rate for the "2026 PCA (No Google)" case.

Q14. Please describe how you calculated the residential rate impacts in the "2026 PCA (No Google) vs. 2026 PCA" comparison.

A14. I used the same rate impact methodology described in the answer above, with the applicable inputs for the "2026 PCA (No Google)" and "2026 PCA" cases. Lines 30 and 31 present the modeled portfolio revenue requirements for the "2026 PCA (No Google)" and "2026 PCA" cases, respectively, as supported by Witness Manning in Exhibit A-2.4. Line 33 presents the renewable compliance costs for the Google comparison based on information supported by Witness Bilyeu. I also updated the production cost allocations as shown in Lines 35 and 36, as described later in my testimony, and the volumetric allocations in Line 38. Lines 48 through 51 summarize the estimated residential rate impacts to the PCA of adding the Google load and related changes modeled while continuing to include the OACS load.

Q15. Please describe how you calculated the residential rate impacts in the "2022 PCA vs. 2026 PCA" comparison.

A15. Line 55 represents the incremental modeled portfolio revenue requirement resulting from the comparison of the "2022 PCA" and "2026 PCA" cases, as supported by Witness Manning in Exhibit A-2.3. Line 57 is the class allocation of the incremental revenue requirement, using the production cost allocations including the impact of both the OACS and Google loads. Line 59 is the revenue requirement projection of the "2022 PCA" case. Lines 61 through 65 summarize the residential rate impacts of the "2026 PCA" in comparison to the "2022 PCA" reference case.

Q16. Can you describe how you determined the production cost allocations for each of the modeled cases?

A16. Yes. The production cost allocations were calculated based on the Company's cost of service model approved in Case No. U-21860 (DTE Electric's 2025 Electric Rate Case). For the modeled cases that include the OACS or Google load, I adjusted those allocations to reflect the estimated effects of the applicable large load or loads. To develop those adjustments, I used the large load cost of service and rate design studies filed in Case No. U-22046 (DTE Electric's 2026 Electric Rate Case) as a basis for recalculating production cost allocators. The large load cost of service and rate design studies evaluate the impact of costs and sales in a hypothetical test year, when both large load customers have achieved their full ramp.

The "2026 PCA (No OACS/Google)" case utilizes production cost allocations from the Case No. U-21860 ordered rate design model, as no OACS or Google loads were present in the Case No. U-21860 ordered revenues, and then assumes these allocators hold flat for all years in the study period.

The "2026 PCA (No Google)" case includes the OACS loads according to the load ramp assumptions supported by Witness Sirwaitis. I used Large Load Study 6 filed in Case No. U-22046 as a basis for calculating production allocators for the "2026 PCA (No Google)" case. Large Load Study 6 includes Large Load Customer 1 (proxy for OACS) and Large Load Customer 2 (proxy for Google) individually broken out on new rate schedules, separate from Rate Schedule D11. When calculating the "2026 PCA (No Google)" allocators at full ramp, I removed Large Load Customer 2 (Google) from the proposed revenues. As OACS is assumed in

the IRP to reach full ramp by January 2028, these calculated allocators reflect the end point (2028) allocators for the "2026 PCA (No Google)" case and are held flat thereafter. I then calculated the 2027 allocators by interpolating between the currently approved 2026 allocators and the end point 2028 allocators, using the average OACS demand by month in the 2027 ramp period as a percentage of the OACS demand at full ramp.

Similarly, the "2026 PCA" and "2022 PCA" cases include both the Google and OACS loads according to the load ramp assumptions supported by Witness Sirwaitis. I used Large Load Study 1 filed in Case No. U-22046 as a basis for calculating production allocators for these cases. As both OACS and Google are modeled in the IRP to reach full ramp by January 2029, these calculated allocators reflect the end point (2029) allocators for the cases including both customers and are held flat thereafter. I then calculated the 2027 and 2028 allocators by interpolating between the 2027 allocators as calculated in the "2026 PCA (No Google)" case above and the end point 2029 allocators, using the average Google demand by month in the 2027 and 2028 ramp period as a percentage of the Google demand at full ramp.

Q17. Can you describe how you determined the volumetric allocations for each of the modeled cases?

A17. Yes. The volumetric allocations represent each class's share of the total forecast sales for each modeled case. The volumetric allocations were used to allocate renewable compliance costs provided by Witness Bilyeu to each class, as renewable compliance costs are recovered volumetrically.

Q18. Should the estimated allocation changes for purposes of this rate impacts analysis be considered a Company proposal regarding cost allocation?

A18. No. The estimated allocations used in this analysis are not proposed for approval or use in setting rates in this IRP proceeding. Discussions on cost allocation and ratemaking are appropriately conducted in rate cases. However, to address the IRP filing requirements and estimate rate impacts for the PCA and other modeled cases which include OACS or Google loads, it would not be appropriate to use the currently approved allocators without adjustment. Holding the current 2026 allocators constant throughout future years would not reflect the estimated effects of the OACS and Google loads on class cost responsibility and, for purposes of this analysis, would overestimate the share of production costs allocated to residential, commercial, and other classes and underestimate the share allocated to the industrial class.

The production cost allocators estimated above were developed solely for the IRP rate impacts analysis and should not be viewed or otherwise treated as proposed ratemaking allocators. They reflect a reasonable estimation of the effects of the large loads on production allocators for the purposes of this IRP analysis, as they are based upon large load studies filed in Case No. U-22046. After costs are approved in this IRP and submitted as part of future rate cases, the actual production allocations will be calculated based on projected test period billing determinants and costs, which will generate the correct production allocations for use in ratemaking.

Q19. Do the rate impacts in Exhibits A-19.1, A-19.2, and A-19.3 follow a similar methodology to Exhibit A-19?

A19. Yes. Exhibits A-19.1, A-19.2, and A-19.3 follow the same rate impact methodology as Exhibit A-19, but evaluate the rate impacts for the commercial, industrial, and other classes, respectively. In each of these rate impact exhibits, I update the following lines to reflect the appropriate class. First, I update the base class revenue requirement projection on Line 2 to reflect the commercial, industrial, or other class, respectively, consistent with the ordered full-service revenues approved in Case No. U-21860. Second, I update the production cost allocations on Lines 10, 11, 35, and 36 consistent with the Case No. U-21860 ordered revenues, and the volumetric allocations on Lines 13 and 38, both updated to include the impact of the OACS and Google loads where applicable, as described above. Third, I update the sales forecasts on Lines 20, 21, 45, and 46 to reflect the commercial, industrial, or other class, respectively, as supported by Witness Sirwaitis.

Q20. Have you calculated the customer rate impact of the 2026 PCA as compared to the 2022 PCA?

A20. Yes. I have calculated the change in average rates between the 2022 PCA and the 2026 PCA for each customer class, over the study period of 2027 through 2046, as shown in Line 65 of Exhibits A-19 through A-19.3. As shown below, the 2026 PCA results in a rate decrease over the study period for all classes when compared to the Company's prior PCA.

Table 1 Average Rate Impact of 2026 PCA (2027-2046)

	Rate Delta
Residential	-4.1%
Commercial	-4.3%
Industrial	-9.6%
Other	-1.2%

Q21. Do the incremental revenue requirements include all expected changes in revenue requirements during the study period?

A21. No, they do not. The incremental revenue requirements are limited to the modeled differences between the cases being compared, such as the difference between the "2022 PCA" and "2026 PCA" cases, as supported by Witness Manning. The analysis is intended to isolate those modeled differences. Any other items are typically addressed in a general rate case (such as changes in rate base, rate of return, depreciation expense, distribution system revenue requirements, etc.) and are excluded from this analysis. I have also used the current rates from Case No. U-21860 and a standard growth rate as a proxy for projected rates. The resulting average rates are analytical estimates and are not forecasts of the rates that the Commission will approve in future proceedings.

Q22. How will the revenue requirement associated with the PCA, as identified by Witness Manning, be recovered?

A22. The revenue requirement associated with the Company's PCA would be recovered in DTE Electric's future general rate cases, related Energy Waste Reduction and

Renewable Energy Plan proceedings, and PSCR filings, as applicable, subject to Commission approval.

PART II: ENERGY BURDEN

Q23. Please summarize the filing requirements for IRP energy burden analysis that you are sponsoring.

A23. There are two IRP filing requirements that pertain to energy burden. The first is summarized in Exhibit B, page 31 of the Commission's December 18, 2025 Order in Case Nos. U-21867 and U-21570, and states that:

> *The utility shall show the affordability impact of the PCA as compared to its previously approved build plan. The utility shall describe its methodology and data sources including but not limited to income-based segmentation, publicly available data used, any limitations of data availability, proxies such as demographics or housing data, etc. Example methodology is in Appendix 2. If any identified income range is expected to increase an energy burden at or above 6%, the utility shall provide a discussion of available assistance, EWR programs and measures, or other options that could aid in mitigating the expected increased energy burden for the areas identified.*

Additionally, per the Commission's Order in Case No. U-21990, the second requirement is to evaluate the energy burden of the PCA with and without the load and related changes to modeled costs associated with OACS. The energy burden of

the PCA with and without the load and related changes to modeled costs associated with Google was also evaluated.

Q24. What information is presented in Exhibit A-19.4?

A24. Exhibit A-19.4 presents the residential energy burden for each of the cases in Part I, the "rate impacts" section of my testimony and exhibits. The energy burden is calculated as the projected annual residential energy expenditures (electricity and natural gas) divided by the weighted average incomes, for each income band defined, as described below.

Q25. Please describe how you calculated the energy burden impacts in more detail.

A25. Exhibit A-19.4 estimates energy burden impacts based on historical weighted average incomes and average gas costs, and projected residential electric usage and rates. The rates used in the analysis (Lines 4 through 7) reflect the average residential rates calculated in Exhibit A-19.

Lines 10 through 13 reflect weighted average incomes as a percentage of the Federal Poverty Level (FPL), for each income band (less than 150% FPL, 150%-200% FPL, greater than 200% FPL, and overall customer base) assuming a family size of 3 people[2]. 150% FPL and 200% FPL were used to set income band cutoffs in this analysis as they represent eligibility levels considered within DTE Energy and State of Michigan low-income programs. The income data is publicly available from the US Census Bureau, Table B19001 (Household Income), and is based on

[2] Family size of 3 people is consistent with DTE's APP credit determination methodology (see MPSC Case No. U-20757, September 10, 2025 Report, Page 148), which is based on the average household size in Michigan according to US Census Bureau.

Line No.

American Community Survey (ACS) 2024 incomes for counties in DTE Electric's service territory, adjusted for inflation thereafter. Incomes from each county are weighted based on the percentage of the population served by DTE Electric.[3]

Line 15 reflects the average residential electric usage across DTE Electric's customer base as supported by Company Witness Sirwaitis. Lines 18 through 21 calculate the annual electricity costs based on the assumed average rates shown in Lines 4 through 7 multiplied by the annual usage shown in Line 15. The average residential gas costs are shown in Line 23 and are sourced from the Energy Information Administration ("EIA") Form 176 (Annual Report of Natural and Supplemental Gas Supply and Disposition) for calendar year 2024 and are inflated thereafter. Gas costs are included to estimate household energy burden but are not caused by the PCA. Additionally, not all DTE Electric customers take gas service from DTE Gas, and some will be subject to different gas costs than those assumed in this analysis.

To arrive at the energy burden calculations for each case, I have added the electricity costs on Lines 18 through 21 to the gas costs on Line 23 to arrive at the household energy expenditures, which I then divided by the weighted average incomes shown on Lines 10 through 13. The resulting energy burden calculations are shown on Lines 27 through 49, columns (e) through (i) for each case modeled and for each income band. Lastly, on Lines 52 through 55, columns (e) through (i), I have included an income calculation corresponding to a 6% energy burden for each of the cases evaluated. In other words, for the 2026 PCA as shown in Line 52,

[3] Weighted incomes are calculated by comparing the county totals in US Census Bureau, Table 2024 ACS-1 B19001 to the DTE service territory data on poweroutage.us (accessed on August 19, 2026).

a household income of $41,975 for a family of three would equate to a 6% energy burden.

Q26. Have you quantified the energy burden impacts of the PCA?

A26. Yes. In columns (k) through (o) of Exhibit A-19.4, I have calculated the delta between the PCA and each of the three other cases. Lines 33 through 49 show the energy burden deltas by income band in comparison to the PCA, and Lines 53 through 55 show the income delta associated with a 6% energy burden in comparison to the PCA.

Q27. Do the energy burden calculations include all expected changes in costs or income during the reflected timeframe?

A27. No. These calculations are meant to identify the incremental changes in energy burden associated with the various IRP-modeled cases. These calculations do not assume changes to average income across DTE Electric's customer base apart from the expected effects of inflation. Additionally, these calculations do not include changes to average gas household expenditures apart from the effects of inflation, but which could vary based on gas usage, market conditions, and other factors. The calculations also do not include changes in electric rate base, rate of return, depreciation expense, or the costs of future distribution or other investments.

Q28. Can you please describe what energy assistance options are available to customers experiencing higher levels of energy burden?

A28. Yes. Customers experiencing a higher energy burden may be eligible for the Low Income Self Sufficiency Plan (LSP), which is the Company's affordable payment

plan (APP) administered by the Michigan Energy Assistance Program (MEAP). In addition to the LSP, the Company offers the Low-Income Assistance (LIA) credit and the Residential Income Assistance (RIA) credit.

Additionally, Witness Kupser discusses the availability of income-qualified Energy Waste Reduction programs that can also be used to mitigate higher levels of energy burden.

Q29. What are the current eligibility requirements for LSP, LIA and RIA?

A29. The LSP is available for vulnerable families at or below 60% of the State Median Income (SMI). The LSP provides affordable monthly payments based on income and energy usage. The plan eliminates any future late payment charges and past due energy charges are frozen while the customer receives a monthly arrears forgiveness credit.

The LIA and RIA credits are bill assistance programs for eligible low-income customers, limited to those with household incomes at or below 150% FPL or via participation in qualifying assistance programs. Under LIA, eligible electric customers may receive monthly bill credits of $50, and eligible gas customers may receive monthly bill credits of $58. Under RIA, eligible electric customers may receive monthly bill credits of $8.50, and eligible gas customers may receive monthly bill credits of $15.40[4].

Q30. What changes are being made to the LIA and RIA credits?

[4] Electric credits per February 19, 2026 Order in Case No. U-21860. Gas credits per September 10, 2026 Order in Case No. U-21973.

A30. Per the June 11, 2026 Order in Case No. U-20757[5], the existing RIA and LIA credit structure will transition to a utility APP structure, with implementation expected by October 1, 2027. The proposed APP framework is designed to limit customers paying more than 6% of their household income on energy expenditures.

Along with participating in the MPSC workgroups addressing affordability, the Company is collaborating with stakeholders and developing a plan to transition these credit-based programs into a unified APP-based structure, which is intended to provide more comprehensive, energy burden-based support to customers.

Q31. Does this conclude your direct testimony?

A31. Yes, it does.

[5] Case No. U-20757 was originally established to review the response to the COVID-19 pandemic, including the statewide state of emergency and to provide guidance to utilities and stakeholders. The docket later evolved to establish and monitor the Energy Affordability and Accessibility Collaborative, to pilot low-income payment plans, and to most recently establish an energy affordability standard.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TERRI L. SCHROEDER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TERRI L. SCHROEDER

Line No.

Q1. What is your name, business address and by whom are you employed?

A1. My name is Terri Schroeder (she/her/hers). My business address is One Energy Plaza, Detroit, MI, 48226. I am employed by DTE Electric Company (DTE Electric or Company) as Director of Energy Storage.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from DePaul University in 2002 with a Bachelor of Science Degree in Business. In 2008, I received a Master of Business Administration from the University of Michigan Ross School of Business and a Master of Science Degree from the University of Michigan School of Natural Resources and Environment.

Q4. What is your professional experience?

A4. I began my career in the marketing department at Jenner & Block, an Am Law 100 law firm based in Chicago. In 2004-2005, I served one year with AmeriCorps at City Year Detroit. During graduate school, I had internships at Ford Motor Company and the Environmental Law and Policy Center. After graduate school, I worked at two different consulting firms: first at Shepherd Advisors (2008-2012) and later at Public Sector Consultants (2012-2014), where I focused on energy policy, energy marketing, and program management.

My employment with DTE Electric began in 2014 when I joined the Renewable Energy team as a Senior Strategist in Business Development. In this role, I

implemented the Company's approved plans to meet the requirements of 2008 Public Act (PA) 295, administering Requests for Proposal (RFPs) for our renewable energy projects, filing contract approval applications with the Michigan Public Service Commission (MPSC or Commission), supporting development of the Company's Renewable Energy Plan (REP) and reconciliation cases, and maintaining the Company's Renewable Energy Credit (REC) compliance records. In 2017, I assumed the role of Manager of Business Development in Renewable Energy, where I was a member of the Company's Renewable Energy Management team and was responsible for planning and executing renewable energy activities for the Company. In 2019, I changed roles to the Product Development Manager in Renewable Solutions, the renewable team focused on voluntary renewable energy products associated with DTE Electric's MIGreenPower programs. In 2020, I became the Chief of Staff for Distribution Operations. In 2022, I returned to Renewable Energy as the Director of Renewable Energy Strategy and Development, and in 2023, I became the Director of Energy Storage in the Company's Clean Energy organization.

Q5. What are your current duties and responsibilities?

A5. I am the Director of Energy Storage on DTE Electric's Clean Energy team. I am a member of the Company's Clean Energy Management team and am responsible for overseeing the development activities for new energy storage projects.

Q6. Have you previously provided testimony before the MPSC?

A6. Yes. I sponsored testimony in the following cases:

U-18242 Reconciliation of the DTE Electric 2016 REP Program

Line No.		
1	U-18352	Section 61 of 2016 PA342
2	U-18419	DTE Electric 2017 Certificate of Necessity
3	U-20172	Reconciliation of the DTE Electric 2017 REP Program
4	U-20343	Application of DTE Electric Company for approval of its Large
5		Customer Voluntary Green Pricing Program
6	U-20471	Application of DTE Electric Company for approval of its integrated
7		resource plan
8	U-20484	Reconciliation of the DTE Electric 2018 REP Program
9	U-18232	Amended 2018 REP
10	U-22046	2026 DTE Electric Rate Case

Line No.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to provide details regarding the Company's energy storage assets in support of the 2026 Integrated Resource Plan (IRP) including:

- An overview of the energy storage market;
- An overview of the battery energy storage system (BESS) projects included in the IRP starting point, modeling assumptions used in the IRP process and the role of additional energy storage contemplated in the proposed course of action (PCA);
- The statutory requirements applicable to energy storage and the Company's plan to comply with the statewide energy storage target.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. No.

Q9. Did you provide inputs to the group responsible for conducting the IRP modeling process?

A9. Yes. As further described by Witness Manning and discussed later in my testimony, I provided the battery energy storage information used to develop the IRP starting point, including DTE Electric's Commission-approved BESS resources through 2029.

Q10. How is your testimony organized?

A10. My testimony consists of the following three parts:

Part I Energy Storage Market

Part II BESS Build and BESS Modeling Assumptions

Part III BESS Statutory Requirements

PART I – ENERGY STORAGE MARKET

Q11. What is the role of energy storage in resource planning?

A11. Energy storage is an important component of the Company's balanced mix of resources and can provide capacity, reliability, operational flexibility benefits, and renewable energy integration benefits. The magnitude and type of benefits provided by an energy storage resource depend on multiple factors including its duration, available charging energy, operating characteristics, and capacity accreditation. Based on the Company's modeling and industry experience, battery energy storage can be a cost-effective solution to address system needs over the planning period. The Company's resource mix is increasingly integrating variable renewable energy, changes in customer demand, and the retirement of fossil fuel generation. Battery energy storage performs several functions to support resource planning and reliability, including the ability to respond nearly instantaneously to changing grid conditions. Additionally, BESS stores excess energy generated from wind and solar sources and dispatches it when demand peaks, potentially preventing renewable energy curtailment and flattening peak demand curves.

Q12. Can you describe the overall growth of energy storage within the Company's energy mix?

A12. Yes. The Company's use of utility-scale energy storage began in 1973 with the Ludington Pumped Storage Plant, which is co-owned with Consumers Energy.

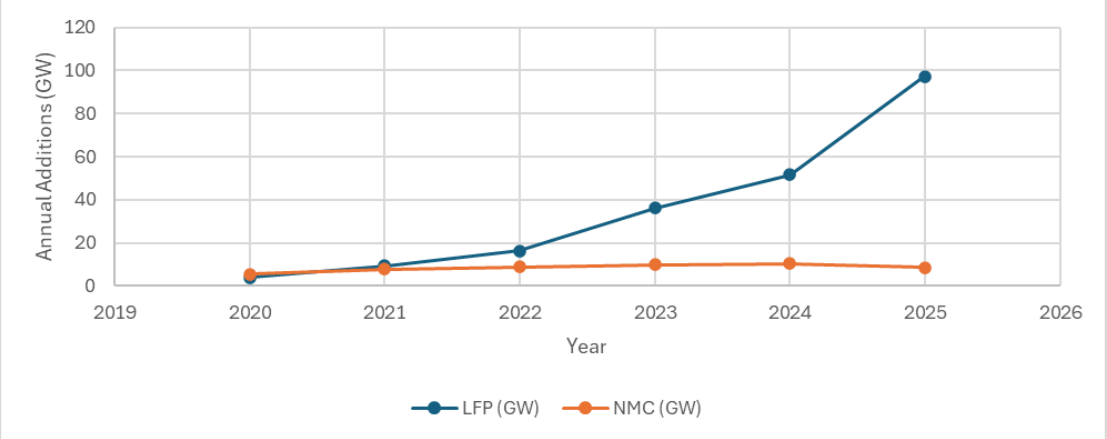
Line No.

Pumped hydro storage was the leading energy storage technology for decades.[1] A major development for the industry was the commercialization and scale-up of lithium-ion battery technology. The Company's first grid-scale battery, Slocum BESS, came online in 2025 to replace the five diesel peaker engines that served customers at the Slocum station site for six decades.

Q13. Why has lithium-ion been the leading technology for battery energy storage systems in the last decade?

A13. Lithium-ion has been the dominant chemistry for standalone BESS, initially with nickel manganese cobalt (NMC) batteries leading the market and lithium iron phosphate (LFP) batteries gaining prominence more recently. The BESS industry has increasingly transitioned to LFP technology due to its performance and stability characteristics compared to NMC technology. Figure 1 shows an illustrative market trend based on published deployment and chemistry-share benchmarks.

Figure 1 Global Additions of BESS by Lithium-ion Chemistry[2][3]



[1] Pumped Storage Hydropower, available at https://www.energy.gov/cmei/water/pumped-storage-hydropower, accessed September 6, 2026.
[2] 1H 2023 Energy Storage Market Outlook | BloombergNEF,
[3] Executive summary – Batteries and Secure Energy Transitions – Analysis - IEA

Lithium-ion has remained the dominant technology due to its lower cost and broader scale, largely driven by the electric vehicle market. The Company uses industry organizations, such as American Clean Power and Electric Power Research Institute (EPRI), to monitor the latest developments in battery energy storage system chemistry makeups.

Q14. What is the typical duration of the BESS in the IRP?

A14. All projects coming online through 2030 are four-hour duration. As discussed later in my testimony, the PCA also includes longer-duration energy storage beginning in 2037.

Q15. What is driving the use of four-hour duration battery energy storage systems?

A15. Four-hour BESS has become the predominant duration for utility-scale battery storage due to a combination of technology economics, industry development, and the capacity accreditation framework historically applicable to energy storage. MISO's resource adequacy construct is evolving, including through implementation of the Direct Loss of Load (DLOL) accreditation methodology beginning in the 2028-2029 Planning Year. DLOL is intended to place greater emphasis on resource performance during periods when the system is at greatest risk of loss of load, which can affect the capacity value of energy storage resources of different durations. As these markets and accreditation methodologies evolve, longer-duration energy storage may provide additional resource adequacy value. Witness Burgdorf further describes MISO's resource adequacy construct and changes in how resources are accredited.

Q16. What is long-duration energy storage (LDES)?

A16. Under MCL 460.1007(g), LDES is defined as an energy storage system capable of continuously discharging electricity at its full rated capacity for more than 10 hours.

Q17. What types of technology comprise LDES?

A17. LDES technologies can generally be categorized as electrochemical, chemical, mechanical, or thermal. Table 1 below provides a high-level overview of each:

Table 1 LDES Technology Types

LDES Technology	Description	Examples
Electrochemical	Conversion of chemical energy into electrical energy and vice versa	• Flow batteries • Lithium and non-lithium battery chemistries
Chemical	Energy is stored within chemical bonds	• Hydrogen
Mechanical	Stores mechanical energy as tension or position	• Pumped storage hydro (PSH) • Compressed air energy storage (CAES) • Gravity storage • Liquid CO_2
Thermal	Energy is stored as heat	• Sensible heat • Latent heat

Q18. Why is there a need for LDES?

A18. Longer-duration energy storage can provide increased reliability, resource adequacy, and operational flexibility benefits compared to shorter-duration energy storage such as four-hour BESS. It can also contribute to grid reliability and

resilience by providing energy over longer periods during stressed system conditions.

The resource adequacy benefits of longer-duration storage may also be reflected in its capacity accreditation. As discussed by Witness Burgdorf, MISO's DLOL methodology evaluates resource performance during periods when the system is at greatest risk of loss of load, which can affect the accredited capacity value of energy storage resources based on their ability to perform during those periods.

Q19. What actions has the State of Michigan taken to progress the development of LDES within the state?

A19. The 2023 PA 235 Section 101 established a statewide energy storage target of 2,500 MW and directed the Commission to conduct a study addressing long-duration and multi-day energy storage. The Commission subsequently implemented the statutory storage requirements through Case No. U-21571, including guidance for utilities regarding energy storage targets and reporting, and emphasizing the inclusion of LDES in IRPs. On February 27, 2025, the MPSC released its *Study of Long-Duration and Multi-Day Energy Storage*[4] report (MPSC Report).

Q20. What observations from the MPSC Report are relevant to evaluating the potential role of LDES in Michigan?

[4] Study of Long-Duration and Multi-Day Energy Storage, available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/2023-Energy-Legislation/Study-of-LDES-and-MDES.pdf, accessed September 6, 2026.

A20. The MPSC Report identifies the variability of renewable generation as a key driver for LDES deployment and recognizes the potential for LDES to smooth intermittent generation, shift energy between periods of surplus and deficit, and help bridge gaps in renewable generation that may extend beyond the capability of shorter-duration storage.[5] The MPSC Study also recognizes LDES as a potential tool for supporting both reliability and resilience as the generation portfolio changes.[6]

Q21. What recommendations for utilities resulted from the MPSC's *Study of Long-Duration and Multi-Day Energy Storage* report?

A21. The MPSC Report recommends that utilities apply appropriate modeling practices so LDES technologies are adequately represented in long-term resource planning. It also recommends that electric providers with fossil-fuel generating resources evaluate the potential role of LDES and Multi-Day Energy Storage (MDES) as part of their analysis of future resource alternatives.[7]

Q22. Did DTE Electric's IRP follow the recommendations and other directives from the MPSC's Report?

A22. Yes. The Company incorporated LDES technologies into its long-term planning analysis and evaluated longer-duration energy storage among the resource alternatives available in the IRP model. Witness Manning provides additional

[5] Michigan Public Service Commission Staff, *Study of Long-Duration and Multi-Day Energy Storage* (Feb. 27, 2025), pp. 25, 50–53, 63.
[6] Michigan Public Service Commission Staff, *Study of Long-Duration and Multi-Day Energy Storage* (Feb. 27, 2025), pp. 25, 50–53, 63.
[7] The MPSC report defines LDES as a storage system continuously discharging for more than 10 hours. MDES is defined as an energy storage system capable of continuously discharging electricity at its full rated capacity for more than 24 hours.

details regarding the modeling methodology and treatment of energy storage technologies.

Q23. Has the Company considered the use of LDES for any of its current energy storage projects?

A23. Yes. Both the Company's 2025 All-Source RFP and 2026 Energy Storage RFP allowed longer-duration energy storage technologies to compete. The 2025 All-Source RFP received two bids involving technologies that met the LDES definition, but neither satisfied the applicable minimum bid requirements due to land control and/or interconnection requirements. See Witness Pratt for more information on the Company's 2025 All-Source RFP.

The Company also evaluated energy storage technologies with durations longer than the four-hour BESS. In the 2026 Energy Storage RFP, DTE Electric submitted an eight-hour lithium-ion project and an eight-hour non-lithium energy storage project. DTE Electric's Competitive Procurement team may have received other bids, but the results are not yet compiled.

Q24. What challenges is the BESS industry currently facing?

A24. The BESS industry currently faces several development and cost-related challenges. One significant challenge is price uncertainty. Rapidly changing tariffs in 2025 on imported BESS equipment, along with tariffs on key materials such as aluminum and steel, have created pricing volatility. This state of uncertainty and price fluctuation has made long-term planning difficult. Beyond tariffs, key minerals used in manufacturing battery energy storage have fluctuated in recent

years. Prices for lithium and other critical minerals used in battery manufacturing have experienced significant price volatility in the last five years. Furthermore, geopolitical developments have created additional uncertainty regarding commodity availability and pricing.

Q25. How did the 2025 One Big Beautiful Bill Act (OBBBA) impact BESS?

A25. OBBBA modified federal clean energy tax policy and introduced additional restrictions relevant to the eligibility and supply chains of certain energy projects. Energy storage remains eligible for applicable investment tax credits, subject to the requirements governing those credits. Witness Busse describes the resource-specific tax-credit assumptions used in the IRP model, and Witness Hajj discusses the related federal policy changes. The law and subsequent federal guidance also established restrictions related to prohibited foreign entities (PFE), which can affect project eligibility and supply-chain decisions.

From an energy storage perspective, China is particularly challenging as the country dominates the battery supply chain with nearly 85% of global battery cell production capacity and substantial shares in cathode and anode active material production.[8] Additionally, the extraction and processing of critical minerals is also highly concentrated geographically, with China in the lead in processing the most critical minerals.

Q26. How has the Company worked to minimize these challenges with its self-build projects?

[8] International Energy Agency, *Batteries and Secure Energy Transitions*, April 2024, p. 12.

A26. For self-build projects, the Company evaluates equipment suppliers and project structures with consideration of domestic content requirements, applicable prohibited foreign entity restrictions, tariffs, and other supply chain risks. Because federal guidance governing PFE restrictions continues to evolve, the Company evaluates potential equipment suppliers with the assistance of legal and tax advisors. Furthermore, DTE Electric's self-build contracts, particularly with energy storage suppliers, clearly identify the impact from tariff changes and commodity pricing.

PART II – BESS BUILD AND BESS MODELING ASSUMPTIONS

Q27. What amount of BESS build is included in the Company's starting point?

A27. The Company's starting point includes energy storage resources in the 2024-2029 timeframe previously approved by the Commission or otherwise incorporated into the Company's planning assumptions and existing resource plan, including the projects approved pursuant to the Case No. U-21193 IRP Settlement Agreement and in subsequent Commission proceedings including Case Nos. U-21297, U-21566, U-21990, U-22054, and U-22060. The IRP starting point also includes, as a planning assumption, 450 MW of battery storage associated with the Google LLC (Google) load and the pending special contract in Case No. U-22058. The Google amount consists of 400 MW of four-hour storage and 50 MW of eight-hour storage assumed to be in service by 2029. The Google storage need remains pending Commission approval, and no specific storage projects have been filed to fulfill that need. Energy storage capacity included in the base modeling assumptions is outlined in Table 2:

Line No.

Table 2 DTE Electric BESS Capacity Additions by COD Year

COD Year	2025	2026	2027	2028	2029
MW (4-hour duration)	14	220	902	1,481	400
MW (8-hour duration)					50

Q28. Can you describe the Company's fleet of battery energy storage projects included in the Company's starting point?

A28. Yes. Table 3 below provides the name, size, commercial operation date (COD), and DTE Electric or third-party ownership for each battery energy storage project:

Table 3 BESS projects in the Company's starting point

BESS Project	Size	COD	DTE/3rdParty
Slocum	14 MW / 56 MWh	2025	DTE
Trenton Channel Energy Center	220 MW / 880 MWh	2026	DTE
Cold Creek	100 MW / 400 MWh	2027	DTE
Fish Creek	132 MW / 528 MWh	2027	DTE
Pine River	100 MW / 400 MWh	2027	DTE
Meridian	225 MW / 900 MWh	2027	DTE
Isabella	170 MW / 680 MWh	2027	DTE
Tuscola II	100 MW / 400 MWh	2027	3rd Party
Coldwater River	75 MW / 350 MWh	2027	3rd Party
2028 OACS [9]	181 MW / 724 MWh	2028	DTE
Waters Edge	350 MW / 1400 MWh	2028	DTE
Fermi	200 MW / 800 MWh	2028	DTE
Big Mitten	450 MW /1800 MWh	2028	3rd Party
Redstart	200 MW / 800 MWh	2028	3rd Party
MI 2	100 MW / 400MWh	2028	3rd Party
2029 Google LLC	400 MW / 1600 MWh	2029	TBD
2029 Google LLC	50 MW / 400 MWh	2029	TBD

[9] Oracle America Cloud Services LLC (OACS)

Line No.

Q29. Can you describe the battery technology of the BESS projects included in the Company's starting point?

A29. Yes. All of the projects identified in Table 3 use LFP lithium-ion battery technology and all have four-hour durations with the exception of the 50 MW eight-hour storage project in 2029.

Q30. What amount of incremental battery energy storage build is included in the Company's PCA?

A30. In addition to the base energy storage included in the starting point, the Company's PCA includes 1,713 MW of incremental energy storage over the 20-year planning period as broken down below in Table 4:

Table 4 BESS Included in the PCA

LDES Duration	In-Service Date	MW
14-hour	2037	1,663 MW
99-hour	2044	50 MW

Q31. What were the assumptions used for capital and operations and maintenance (O&M) costs for energy storage?

A31. Witness Busse describes the cost assumptions incorporated into the IRP modeling.

PART III – BESS STATUTORY REQUIREMENTS

Q32. What statutory energy storage target is the Company required to meet?

A32. The 2023 PA 235 established a statewide energy storage target of 2,500 MW by December 31, 2029, codified in MCL 460.1101.[10] The statute requires each electric provider to meet its proportional share of the statewide target, and the Commission has implemented the allocation and reporting requirements through Case No. U-21571. In Case No. U-21907[11], DTE Electric's 2026 portion of that target was determined to be 1,127.2 MW.

Q33. Does the Company expect to meet this energy storage requirement?

A33. Yes. Based on the existing and approved BESS projects identified in Table 3, the Company expects to have more than 3 GW of energy storage on its system by 2029, which exceeds DTE Electric's allocated share of the statewide energy storage target. The statutory energy storage target establishes a minimum amount of storage the Company is required to procure but does not limit the amount of energy storage that may be appropriate as part of the Company's long-term resource plan. Witness Manning further describes the IRP modeling and the basis for the amount and timing of energy storage included in the PCA.

The Company will continue to provide the Commission with the required annual energy storage updates consistent with Case No. U-21571.

Q34. Has the Company followed the Commission-approved Competitive Procurement Guidelines in Case No. U-20852?

[10] 2023 PA 235, Sections 101, MCL 460.1101(1)-(9) establish a statewide energy storage target of 2,500 megawatts (MW) by December 31, 2029.
[11] MPSC Staff, Statewide Energy Storage Target Calculation, Case No. U-21907, filed 2026.

A34. Yes. The Company has followed the Commission's applicable Competitive Procurement Guidelines for RFPs soliciting energy storage resources, as established in Case No. U-20852. The Company documents its adherence with the competitive procurement guidelines in its individual energy storage contract filings with the Commission.

Q35. Is the Company requesting pre-approval for capital expenditures associated with a grid-scale BESS in this proceeding?

A35. No.

Q36. Does this conclude your testimony?

A36. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, Clean Energy Plan pursuant to MCL 460.1051, Certificates of Necessity pursuant to MCL 460.6s, related accounting authorizations, and for other relief.	)))))))	Case No. U-22168

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF THERESA M. UZENSKI

Line No.

Q1. What is your name, business address, and by whom are you employed?

A1. My name is Theresa M. Uzenski. I am employed by DTE Energy Corporate Services, LLC, a subsidiary of DTE Energy Company (DTE Energy). My business address is One Energy Plaza, Detroit, MI 48226.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I have a Bachelor of Science in Accounting from the University of Detroit and a Master of Business Administration with a concentration in Finance from Wayne State University.

Q4. What is your professional experience?

A4. I have worked for DTE Energy or one of its affiliated regulated utilities for thirty-seven years in various accounting, finance, and management positions. I am currently the Manager of Regulatory Accounting for DTE Electric Company and DTE Gas Company.

Q5. What are your current duties and responsibilities?

A5. As Manager of Regulatory Accounting, I am responsible for the development and management of regulatory accounting policies and practices, as well as supporting regulatory filings. My department analyzes the accounting implications of new legislation and Michigan Public Service Commission (MPSC or Commission)

orders and provides expert testimony on accounting issues and financial projections in various proceedings before the MPSC. We research and establish accounting policies and assist the accounting operations departments with implementation. My department also supports other Company expert witnesses in various proceedings before the MPSC by preparing financial exhibits and other financial analyses.

Q6. Do you hold any certifications or are you a member of any professional organizations?

A6. I am a Certified Management Accountant, a member of the Institute of Management Accountants, and a member of the Corporate Accounting Committee of the Edison Electric Institute and American Gas Association.

Q7. Have you previously sponsored testimony before the MPSC?

A7. Yes. I have sponsored testimony in the following cases:

U-11222	Michigan Consolidated Gas Company (MichCon) Depreciation
U-13898	MichCon Uncollectible Expense True-up Mechanism (UETM)
U-14702	Detroit Edison 2006 Power Supply Recovery (Power Supply Recovery) Plan
U-15160	Detroit Edison Enhanced Security Cost Recovery
U-15244	Detroit Edison Choice Incentive Mechanism (CIM) Reconciliation
U-15259	Detroit Edison Pension Equalization Mechanism
U-15417-R	Detroit Edison Pension Equalization Mechanism
U-15806-EO	Detroit Edison Energy Optimization
U-15768	Detroit Edison UETM
U-15890	MichCon Energy Optimization

Line No.		
1	U-16009	Complaint Case against Detroit Edison
2	U-16246-R	Detroit Edison 2009 Restoration Expense Tracking Mechanism
3		(RETM) Reconciliation
4	U-16578-R	Detroit Edison 2010 RETM Reconciliation
5	U-16356	Detroit Edison 2009 REP Reconciliation
6	U-16472	Detroit Edison 2010 Rate Case
7	U-16574	Detroit Edison 2010 UETM Reconciliation
8	U-16582	Detroit Edison 2011 Renewable Energy Plan (REP)
9	U-16769	MichCon Depreciation
10	U-16952	Detroit Edison 2011 CIM Reconciliation
11	U-16956	Detroit Edison 2011 RETM Reconciliation
12	U-16964	Detroit Edison 2011 UETM Reconciliation
13	U-17302	DTE Electric Company 2013 REP Plan Update
14	U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
15	U-17767	DTE Electric Company 2014 Rate Case
16	U-17999	DTE Gas Company 2015 Rate Case
17	U-18014	DTE Electric Company 2016 Rate Case
18	U-18122	DTE Electric Company Customer 360 Program Accounting
19	U-18255	DTE Electric Company 2017 Rate Case
20	U-18419	DTE Electric Company Certificates of Necessity
21	U-18999	DTE Gas Company 2018 Rate Case
22	U-20106	DTE Gas Tax Cuts & Jobs Act – Credit A
23	U-20105	DTE Electric Tax Cuts & Jobs Act – Credit A
24	U-20162	DTE Electric Company 2018 Rate Case
25	U-20298	DTE Gas Tax Cuts & Jobs Act – Credit C

Line No.		
1	U-20561	DTE Electric Company 2019 Rate Case
2	U-20642	DTE Gas Company 2019 Rate Case
3	U-20940	DTE Gas Company 2021 Rate Case
4	U-21015	DTE Electric Company 2021 Securitization
5	U-20836	DTE Electric Company 2021 Rate Case
6	U-21193	DTE Electric Company 2022 Integrated Resource Plan
7	U-21297	DTE Electric Company 2023 Rate Case
8	U-21291	DTE Gas Company 2024 Rate Case
9	U-21534	DTE Electric Company 2024 Rate Case
10	U-21860	DTE Electric Company 2025 Rate Case
11	U-21973	DTE Gas Company 2025 Rate Case
12	U-22046	DTE Electric Company 2026 Rate Case

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to support the Company's financing plan for two new carbon capture and storage-ready (CCS-ready) combined cycle natural gas turbine (CCGT) facilities supported by Witness Stansell.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. No, I am not.

Proposed Financing

Q10. What is the Company's financing plan for the CCS-ready CCGT projects?

A10. The Company's financing plan provides for current recovery of financing costs in base rates to the extent that the projects are reflected in approved rate base, and the application of allowance for funds used during construction (AFUDC) to any balances not included in base rates.

Q11. What do you mean by current recovery of financing costs?

A11. In a general rate case, the projected balance of construction work in progress (CWIP) for the CCS-ready CCGT projects would be reflected in the projected test period rate base without an AFUDC offset.

Q12. How does the financing plan address construction costs not reflected in base rates?

A12. Construction costs not included in rate base will accrue AFUDC until they are reflected in base rates.

Q13. Has the Commission approved this type of financing for other DTE Electric assets?

A13. Yes. The Company proposed the same financing plan in Case No. U-18419, in which DTE Electric requested a Certificate of Necessity for its natural gas combined cycle generating facility, the Blue Water Energy Center, and the Commission approved the plan in its April 27, 2018 Order in that case.

Q14. What is the ratemaking treatment for AFUDC that is capitalized before the projects are reflected in a rate case?

A14. In a rate case that reflects the CCS-ready CCGT projects in CWIP, the Company will reduce the CWIP balance by any AFUDC capitalized (i.e., AFUDC accrued prior to the project being reflected in approved rate base) for ratemaking purposes. This will ensure that the Company does not earn a return on capitalized AFUDC while the asset is still under construction.

Q15. Will AFUDC be accrued on construction costs incurred between rate cases?

A15. Yes, to the extent those construction costs were not reflected in approved base rates. If the projected test period of a rate case included the estimated CWIP for the projects, no AFUDC would be accrued on that amount. However, AFUDC would be accrued on the incremental capital costs incurred (e.g., if the construction period extended beyond the projected test period).

Q16. Why is the Company proposing this financing plan?

A16. The current recovery component of the financing plan would reduce the total capitalized cost of the assets reflected in rate base, thereby reducing future revenue requirements.

Q17. Why does the Company believe that the Commission may approve the proposed financing plan?

A17. Based on my review of MCL 460.6s, the statute authorizes the Commission to approve a financing plan for a proposed electric generation facility and permits the Commission to allow recovery of financing costs on construction work in progress for projects approved under a Certificate of Necessity (CON). Such approval would be consistent with the Commission's April 27, 2018 Order in Case No. U-18419.

Q18. What would be the accounting treatment if the Commission does not approve the current recovery component of the financing plan for the CCS-ready CCGT projects?

A18. DTE Electric would use traditional accounting and ratemaking treatment of financing costs (i.e., AFUDC) incurred during the construction period.

Q19. Does this conclude your direct testimony?

A19. Yes, it does.