DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

DTE

Lauren D. Donofrio
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November 3, 2022

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Re: In the matter of the Application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief
MPSC Case No. U-21193 (Paperless e-file)

Dear Ms. Felice:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Application, Protective Order, Nondisclosure Certificates, Testimony and Exhibits of Witnesses, Joyce E. Leslie, Laura K. Mikulan, Shayla D. Manning, Rodrigo Cejas Goyanes, Kevin Carden, Justin L. Morren, Keegan O. Farrell, Kevin L. Bilyeu, Vielka M. Hernandez, Markus B. Leuker, Shawn D. Burgdorf, Sonjoy D. Roy, Grace N. Musonera, Ryan C. Pratt, Timothy J. Lepczyk, Theresa M. Uzenski, Aaron Willis, Barry J. Marietta and Adella F. Crozier. Also attached is the Proof of Service.

Confidential Exhibits A-6.3, A-6.4, and A-15.4 will be filed under seal with the Commission. The confidential exhibits will be sent to the persons who have signed the Non-Disclosure Certificate associated with the Protective Order issued in this proceeding.

Very truly yours,

Lauren D. Donofrio

Digitally signed by Lauren D. Donofrio
Date: 2022.11.03 12:58:59 -04'00'

Lauren D. Donofrio

LDD /erb
Attachments
cc: Service List

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	)	Case No. U-21193
pursuant to MCL 460.6t, and for other relief	)	

APPLICATION

DTE Electric Company ("DTE Electric" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") issue an order approving the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2006 PA 341, MCL 460.6t, the Commission's September 24, 2021 and February 18, 2021 orders in Case No. U-20633, February 18, 2021 and December 20, 2017 orders in Case No. U-18461, November 21, 2017 order in Case No. U-18418, and all other applicable law. In support of this Application, DTE Electric states as follows:

I. INTRODUCTION

1. DTE Electric is a wholly owned subsidiary of DTE Energy that supplies retail electric service to customers located in Michigan. The Company's business address is One Energy Plaza, Detroit, Michigan, 48226. Any correspondence concerning this application shall be directed to its attorneys at their business address provided below.

2. DTE Electric's retail electric business is subject to the jurisdiction of the Commission pursuant to various provisions of 1909 PA 106, as amended, MCL 460.551, *et seq*, 1919 PA 419, as amended, MCL 460.54, *et seq*, 1939 PA 3, as amended, MCL 460.1, *et seq*, including 2016 PA 341 ("the Act"). Pursuant to these statutory provisions, the Commission has the power and jurisdiction to regulate DTE Electric's retail electric rates.

3. In this Application, DTE Electric presents a robust IRP that explores a multitude of variables to reach a reasoned plan that is right for our customers and for Michigan. The Company considered its current portfolio, capacity needs, regulatory and environmental compliance, stakeholder input, and the Company's planning objectives in developing its IRP. The Company also focused on providing reliable and affordable power from a diverse mix of cleaner energy resources including solar, wind, storage, and natural gas. Through the IRP process, DTE Electric has developed a Proposed Course of Action ("PCA") that identifies the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2042. DTE Electric's PCA includes:

a. Develops 6,500 MW of solar;
b. Develops 8,900 MW of wind;
c. Develops 1,810 MW of battery storage;
d. Ceases coal-fired generation operations at Belle River and converts it from a 1,270 coal-fired baseload power plant to a 1,270 MW natural gas peaking resource in 2025 (Unit 1) and 2026 (Unit 2), with the converted Belle River peaking resource retiring by 2040;
e. Retires Monroe Power Plant Units 3 and 4, a total of 1,535 MW of coal-fired generation in 2028 – nearly 12 years earlier than previously announced - and retires Units 1 and 2, 1,531 MW of coal-fired generation, in 2035 – nearly 5 years earlier than previously announced;
f. Incorporates the maximum amount of achievable EWR potential identified in the 2021 Michigan EWR Statewide Potential Study (Statewide Potential Study), an average of 1.5% per year over the study period;
g. Deploys 38 MW of conservation voltage reduction/volt-var optimization (CVR/VVO);

h. Incorporates 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. While low and zero carbon dispatchable technologies to support net zero goals are still emerging and require further development, the technology currently selected in the IRP is a natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS).

4. The resources in the PCA are incremental to the investments currently approved in the Company's 2019 IRP or other regulatory filings that continue to be implemented (e.g., solar, demand response and CVR/VVO).

5. DTE Electric's PCA for years 2023-2042 is fully integrated and requires approval in its entirety.

II. DEVELOPMENT OF THE IRP AND OVERVIEW OF THE PCA

6. The required components of an IRP filing are specifically provided in MCL 460.6t(5)(a)-(o). Furthermore, MCL 460.6t(8) provides that the Commission shall approve a proposed IRP if the Commission determines that the IRP represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make such a determination, the Commission must consider whether the proposed IRP appropriately balances the following factors:

(i) Resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement.

(ii) Compliance with applicable state and federal environmental regulations.

(iii) Competitive pricing.

(iv) Reliability.

(v) Commodity price risks.

(vi) Diversity of generation supply.

(vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL

> 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective. [MCL 460.6t(8).]

7. Pursuant to MCL 460.6t, the Commission was required to: (i) establish modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing an IRP and (ii) establish filing requirements, including application forms and instructions, and filing deadlines for an IRP filed by a utility regulated by the Commission. Specifically, MCL 460.6t(1)(f) provides that the Commission shall:

> (f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:
>
> (i) Any required planning reserve margins and local clearing requirements.
>
> (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.
>
> (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.
>
> (iv) Any regional infrastructure limitations in this state.
>
> (v) The projected costs of different types of fuel used for electric generation.

Furthermore, MCL 460.6t(3) provides, in relevant part, that:

> The commission shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission.

8. In compliance with the above statutory provisions, the Commission issued an order dated November 21, 2017 in Case No. U-18418 approving "Michigan Integrated Resource Planning Parameters." The Commission also issued December 20, 2017 order in Case No. U-18461, which approved "Integrated Resource Plan Filing Requirements." Moreover, on February 18, 2021 and September 24, 2021, the Commission issued orders in Case No. U-20633 directing

utilities filing near-term IRPs to include an additional scenario ("Carbon Reduction Scenario"), inclusive of two carbon sensitivities and certain emissions targets. These documents set forth all required IRP modeling scenarios and assumptions, requirements, instructions, and guidelines for utilities seeking relief pursuant to MCL 460.6t.

9. DTE Electric's IRP meets the statutory requirements under MCL 460.6t, the filing requirements of U-18461, and specific directives included in the Commission's order in the Company's last IRP, Case No. U-20471. Accompanying this Application are the Company's testimony and exhibits, which address the components required to be included in an IRP, address each factor the Commission must consider in approving an IRP, address the Commission's specific requests, and establish that DTE Electric's PCA is "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." MCL 460.6t(8). Commensurate with this filing, the Company has provided a spreadsheet showing how DTE Electric has complied with each of the filing requirements as Exhibit A-1.

10. The Company also addresses the planning objectives set forth by the Commission and DTE Electric's complementary planning objectives, which are Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean.

11. The DTE Electric 2022 IRP meets the Commission's modeling scenarios, assumptions, and filing requirements. The Company's modeling utilizes eight scenarios; three that were required under the Michigan Integrated Resource Planning Parameters (MIRPP), pursuant to the Commission's order implementing section 6t of the Act (Business as Usual (BAU), Emerging Technologies (ET), Environmental Policy (EP)); a fourth required under the Executive Directive 2020-10, pursuant to the Commission's order in Case No. U-20633 (Carbon Reduction (CR)); scenarios five and six, specifically developed on Company assumptions (Reference (REF) and High Electrification (HE)); scenario seven was developed through collaboration of our stakeholders (STAKE), and finally an eighth, a refresh of the REF incorporating updated natural

gas prices, wholesale electricity prices and the Inflation Reduction Act (IRA) tax credit impacts (REFRESH).

12. As identified in the section 6t requirements, the prescribed scenarios use the 2021 Annual Energy Outlook from the U. S. Energy Information Administration "Natural Gas: Henry Hub Spot Price: Reference Case" (2021 EIA gas forecast) and do not include a CO_2 emission cost adder, as it was not needed to reach the specified CO_2 reduction targets for the four required scenarios. For each of the eight IRP scenarios, various sensitivities were run. The sensitivities included those required by the Commission orders, those requested by stakeholders, and some that DTE Electric utilized to show a robust range of possible future outcomes. Sensitivities included varying levels of load, EWR, resource alternatives, renewable energy, storage, gas prices, retirement dates, transmission/capacity purchases, demand response, carbon reduction targets, ancillary service, retail choice caps, and CO_2 emission adders.

13. As part of developing its 2022 IRP, DTE Electric conducted a stakeholder outreach process consisting of open houses, customer research and technical workshops. The Company conducted eight public open house events, performed qualitative and quantitative research with approximately 1,300 residential customers, 400 commercial and industrial customers, and 150 community representatives, and invited more than 40 organizations to participate in six technical workshops. These events provided stakeholders with numerous opportunities to provide input on how to meet Michigan's future energy and capacity needs, including reviewing and commenting on IRP inputs, sensitivities, and technology options.

14. Upon completion of the IRP modeling process, the Company determined that it did not have a capacity need to be filled in the first five (5) years of the IRP planning period.

15. The Company tested its PCA using a rigorous risk assessment methodology consistent with the Commission's orders in U-18461. Five risk-analysis methodologies were used to test the feasibility of the proposed course of action: a Stochastic economic risk analysis, a resource

adequacy analysis, evaluation of key inputs (changes since the commencement of the IRP modeling process), portfolio metric evaluation, scenario and global sensitivity analysis.

16. The Company includes with this filing an IRP Report detailing DTE Electric's existing generation portfolio and PPAs, modeling, resource adequacy, and selection of the PCA as Exhibit A-3.1.

III. COST PRE-APPROVALS

17. MCL 460.6t(11) provides that, in approving an IRP, the Commission shall specify the approved costs for future recovery as follows:

> 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 facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase 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.

18. DTE Electric proposes pre-approval of capital costs related to conversion of the Belle River Power Plant and Demand Response. Because this is the repowering of an existing asset, and not the construction of new generation or addition of a new generating unit, the Company was not required to submit an application under MCL 460.6s. MCL 460.6t(13).

19. More specifically, DTE Electric requests pre-approval of:

a. $135 million for natural gas conversion of the Belle River Power Plant;

b. $8.7 million for continuation of existing Demand Response programs.

IV. CAPACITY NEED AVOIDED COSTS

20. DTE Electric does not have a capacity need in the first five (5) years of its PCA.

21. DTE Electric does not address PURPA avoided cost rates in this IRP. Avoided costs were the subject of the Commission's September 26, 2019 order in Case No. U-18091, which

covers the period through May 31, 2025. The Company will file its next MCL 460.6v PURPA avoided cost six (6) months after issuance of a final appealable order in this proceeding.

V. FINANCIAL COMPENSATION MECHANISM (FCM)

22. DTE Electric requests the Commission approve a FCM in the amount of its after tax weighted average cost of capital, applicable to all new and modified power purchase agreements the Company may enter. This would also update the current methodology in use for power purchase agreements included in the Voluntary Green Pricing program pursuant to MCL 460.1061.

VI. REGULATORY ASSET TREATMENT

23. DTE Electric requests regulatory asset treatment for the remaining net book value of the Monroe Power Plant and the Belle River Power Plant's coal handling assets. The regulatory asset treatment includes cost of removal and decommissioning, as well as the capital expenditures incurred at Monroe to operate safely and reliably until retirement subject to review in future general rate cases.

VII. TESTIMONY AND EXHIBITS

24. Concurrently with filing this Application, DTE Electric is also filing written testimony and exhibits in support of its IRP and other relief sought in this case. The relief described in the testimony and exhibits should be considered as if specifically requested in this Application. DTE Electric expressly reserves the right to revise, amend, or otherwise change the relief it is requesting throughout the proceeding up to and including any exceptions and replies to exceptions to the Proposal for Decision. DTE Electric also reserves the right, pursuant to MCL 460.6t(7) to update the cost estimates within 150 days of the filing of the Application.

VIII. OTHER ISSUES

25. In the event that the Commission issues an order in another case that materially impacts this matter, or DTE Electric's requests in this proceeding, that order or orders may need to be considered in this case.

26. The Company has included a Letter of Transmittal as Attachment A to this Application, as required by the Commission's IRP filing requirements approved in Case No. 18461. The Company's Letter of Transmittal expresses a commitment to the Company's proposed course of action and resource acquisition strategy and has been signed by an officer of the Company who has authority to commit the Company to the resource acquisition strategy, acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

27. Due to the confidential nature of much of the information contained in and included with the Company's IRP filing, the Company is proposing entry of a protective order. The Company's proposed protective order is included as Attachment B to this Application. The Company requests that the entry of its proposed protective order be considered during the prehearing conference for this matter.

IX. REQUEST FOR RELIEF

WHEREFORE, DTE Electric Company requests that the Michigan Public Service Commission:

A. Approve DTE Electric's Integrated Resource Plan by approving the Proposed Course of Action as the most reasonable and prudent means of meeting the Company's energy and capacity needs;

B. Find that DTE Electric does not have a material long term need for generation capacity beginning in any of the next five (5) years;

C. Pre-approve DTE Electric's proposed costs for conversion of the Belle River Power Plant, commencing within three years following the Commission's approval of the Company's Integrated Resource Plan;

D. Approve DTE Electric's Financial Compensation Mechanism;

E. Approve regulatory asset treatment for the remaining net book values of the Monroe Power Plant and the Belle River Power Plant's coal handling assets including cost of removal, decommissioning, and capital expenditures incurred at Monroe after the initial regulatory asset reclassification subject to review in future general rate cases; and

F. Grant DTE Electric any other and further relief as is just and reasonable.

Respectfully submitted,
DTE ELECTRIC COMPANY
Legal Department

By: Lauren D. Donofrio Digitally signed by Lauren D. Donofrio Date: 2022.11.03 13:04:55 -04'00'

Lauren D. Donofrio (P66026)
Andrea E. Hayden (P71976)
Paula Johnson-Bacon (P55862)
Jon P. Christinidis (P47352)
Carlton D. Watson (P77857)
Breanne K. Reitzel (P81107)
One Energy Plaza, 1635 WCB
Detroit, MI 48226
(313) 235-4017

Dated: November 3, 2022

DTE ELECTRIC COMPANY

By: Marco A. Bruzzano Digitally signed by Marco A. Bruzzano Date: 2022.11.03 13:06:30 -04'00'

Marco Bruzzano
Senior Vice President, Corporate Strategy & Regulatory Affairs

Dated: November 3, 2022

ATTACHMENT A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY for	)	Case No. U-21193
approval of its Integrated Resource Plan	)	
pursuant to MCL 460.6t, and for other relief	)	

TRANSMITTAL LETTER

I, Angela P. Wojtowicz, hereby express DTE Electric Company's commitment to the Company's approved Integrated Resource Plan Proposed Course of Action, which represents the Company's preferred resource plan and resource acquisition strategy, and hereby sign this Letter of Transmittal as an officer of the Company having the authority to commit the Company to the resource acquisition strategy, acknowledging that the Company reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

Angela P. Wojtowicz Digitally signed by Angela P. Wojtowicz Date: 2022.11.03 13:45:29 -04'00'

Angela P. Wojtowicz
Vice President, Business Planning & Development

DTE Electric Company

Dated: November 3, 2022

ATTACHMENT B

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY for	)	Case No. U-21193
approval of its Integrated Resource Plan	)	
pursuant to MCL 460.6t, and for other relief	)	

PROPOSED PROTECTIVE ORDER

This Protective Order governs the use and disposition of Protected Material that DTE Electric Company ("Applicant") or any other Party discloses to another Party during the course of this proceeding. The Applicant or other Party disclosing Protected Material is referred to as the "Disclosing Party," the recipient is the "Receiving Party" (defined further below). The intent of this Protective Order is to protect non-public, confidential information and materials so designatedby the Applicant or by any other party, which information and materials contain confidential, proprietary, or commercially sensitive information. This Protective Order defines "Protected Material" and describes the manner in which Protected Material is to be identified and treated. Accordingly, it is ordered:

I. "PROTECTED MATERIAL" AND OTHER DEFINITIONS

A. For the purposes of this Protective Order, "Protected Material" consists of trade secrets or confidential, proprietary, or commercially sensitive information provided in Disclosing Party's Exhibits, work papers, discovery or audit responses, any witness' related exhibit and testimony, and any arguments of counsel describing or relying upon the Protected Material. Subject to challenge underParagraph IV.A, Protected Material shall consist of non-public confidential information and materials including, but not limited to, the following information disclosed during the course of this case if it is marked as required by this Protective Order:

1. Trade secrets or confidential, proprietary, or commercially sensitive informationprovided in response to discovery, in response to an order issued by the presiding hearing officer or the Michigan Public Service Commission ("MPSC"or the "Commission"), in testimony or exhibits filed later in this case, or in arguments of counsel;

    a. Examples of such trade secrets, confidential, proprietary, or commercially sensitive information include, but are not limited to, information regarding compensation, generation, transmission and distribution facilities and related equipment, infrastructure, energy market projections or assumptions, forecasts, gas conversion analyses, sensitivity analyses, revenue requirement analyses, risk assessments, retirement analyses, fuel supply analyses, or financial arrangements including but not limited to those set forth in contracts.
    b. Exclusions include Critical Energy Infrastructure Information ("CEII"), technical data subject to U.S. export control laws and regulations, includingbut not limited to 10 C.F.R. Part 810 *et. seq*., North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) material and information, DTE Electric distribution system information andoperational data including Supervisory Control and Data Acquisition (SCADA) information, confidential Midcontinent Independent System Operator (MISO) and ITC Holdings Corp and/or its affiliate companies' information in the possession of DTE Electric Company, and information regarding Cyber Security, which shall not be disclosed pursuant to this Protective Order or under any other circumstance. No individual DTE Energy employee's compensation benefits or other personal information isrelevant in this proceeding.
2. To the extent permitted, information obtained under license from a third-party licensor, to which the Disclosing Party or witnesses engaged by the DisclosingParty is a licensee, that is subject to any confidentiality or non-transferability clause. This information includes reports; analyses; models (including related inputs and outputs); trade secrets; and confidential, proprietary, or commercially sensitive information that the Disclosing Party or one of its witnesses receives as a licensee and is authorized by the third-party licensor todisclose consistent with the terms and conditions of this Protective Order.

3. Information that could identify the bidders and bids, including the winning bid, in a competitive solicitation for a power purchase agreement, build-transfer agreement, or in a competitively bid engineering, procurement, or construction contract at any stage of the selection process (*i.e.,* before the Disclosing Party has entered into a power purchase agreement, build transfer agreement, or selected a contractor).

B. The information subject to this Protective Order does not include:

1. Information that is or has become available to the public through no fault of the Receiving Party or Reviewing Representative and no breach of this Protective Order, or information that is otherwise lawfully known by the Receiving Partywithout any obligation to hold it in confidence;
2. Information received from a third party free to disclose the information withoutrestriction;
3. Information that is approved for release by written authorization of the Disclosing Party, but only to the extent of the authorization;
4. Information that is required by law or regulation to be disclosed, but only to theextent of the required disclosure; or
5. Information that is disclosed in response to a valid, non-appealable order of a court of competent jurisdiction or governmental body, but only to the extent theorder requires.

C. The parties agree that this protective order is insufficient to protect particularly sensitive commercial information regarding current contract negotiations and contract-re-negotiations and such information shall not be disclosed without agreement of the parties or furtherproceedings regarding this information including, but not limited to, a determination by the presiding officer whether, and if so to what extent, the material is to be disclosed, and any additional protections that may be necessary on a case by case basis. The parties reserve the rightto exhaust any appeals to the Commission and any court or appellate court of competent jurisdiction prior to making any ordered disclosure.

D. "Party" refers to the Applicant, MPSC Staff ("Staff"), Michigan Attorney General,or any other person, company, organization, or association that is granted intervention in Case No.U-21193 under the Commission's Rules of Practice and Procedure, Mich Admin Code, R792.10401 et al.

E. "Receiving Party" means any Party to this proceeding who requests or receives access to Protected Material, subject to the requirement that each Reviewing Representative sign a Nondisclosure Certificate attached to this Protective Order as Attachment 1.

F. "Reviewing Representative" means a person who has signed a Nondisclosure

Certificate and who is:

1. An attorney who has entered an appearance in this proceeding for a ReceivingParty;
2. An attorney, paralegal, or other employee associated, for the purpose of this case, with an attorney described in Paragraph I.F.1;
3. An expert or employee of an expert retained by a Receiving Party to advise, prepare for, or testify in this proceeding; or
4. An employee or other representative of a Receiving Party with significant responsibility in this case.

G. Reviewing Representative is responsible for assuring that persons under his or her supervision and control comply with this Protective Order.

H. "Nondisclosure Certificate" means the certificate attached to this Protective Order as Attachment 1, which is signed by a Reviewing Representative who has been granted access to Protected Material and agreed to be bound by the terms of this Protective Order.

II. ACCESS TO AND USE OF PROTECTED MATERIAL

A. This Protective Order governs the use of all Protected Material that is marked as required by Paragraph III.A and made available for review by the Disclosing Party to any Receiving Party or Reviewing Representative. This Protective Order protects: (i) the Protected Material; (ii) any copy or reproduction of the Protected Material made by any person; and (iii) anymemorandum, handwritten notes, or any other form of information that copies, contains, or discloses Protected Material. All Protected Material in the possession of a Receiving Party shall be maintained in a secure place. Access to Protected Material shall be limited to persons authorizedto have access subject to the provisions of this Protective Order.

B. Protected Material shall be used and disclosed by the Receiving Party solely in accordance with the terms and conditions of this Protective Order. A Receiving Party may authorize access to, and use of, Protected Material by a Reviewing Representative identified by the Receiving Party, subject to Paragraphs III and V below, only as necessary to analyze the

Protected Material; make or respond to discovery; present evidence; prepare testimony, argument,briefs, or other filings; prepare for cross-examination; consider strategy; and evaluate settlement. These individuals shall not release or disclose the content of Protected Material to any other personor use the information for any other purpose. The Disclosing Party retains the right to object to any designated Reviewing Representative if the Disclosing Party has reason to believe that there is an unacceptable risk of misuse of confidential information. If a Disclosing Party objects to a Reviewing Representative, the Disclosing Party and the Receiving Party will attempt to reach an agreement to accommodate that Receiving Party's request to review Protected Material. If no agreement is reached, then either the Disclosing Party or the Receiving Party may submit the dispute to the presiding hearing officer. If the Disclosing Party notifies a Receiving Party of an objection to a Reviewing Representative, then the Protected Material shall not be provided to that Reviewing Representative until the objection is resolved by agreement or by the presiding hearing officer.

C. Before reviewing any Protected Material, including copies, reproductions, and copies of notes of Protected Material, a Receiving Party and Reviewing Representative shall signa copy of the Nondisclosure Certificate (Attachment 1 to this Protective Order) agreeing to be bound by the terms of this Protective Order. The Reviewing Representative shall also provide a copy of the executed Nondisclosure Certificate to the Disclosing Party.

D. No person who is afforded access to any Protected Material by reason of this Ordershall disclose the Protected Material to anyone not specifically authorized to receive such information pursuant to the terms of this Order. Nor shall such persons use the Protected Materialin any manner inconsistent with this Order. All persons afforded access to Protected Material pursuant to this Order shall keep the Protected Material secure in accordance with the purposes and intent of this Order and shall adopt all reasonable precautions to assure continued confidentiality, including precautions against unauthorized copying, use, or disclosure thereof.

E. A party seeking or intending to disclose in or on the public record information taken directly from materials identified as Protected Material must – before actually disclosing the information – do one of the following: (a) contact DTE Electric's counsel of record and obtain written permission to place the information in the public record, (b) take affirmative steps to confirm and actually confirm that the information is otherwise public information and within an exclusion in section 7 of this Order and comply with the notice provisions in section 7, or (c) challenge the confidential nature of the Protected Material and obtain a ruling under section 10 that the information is not confidential and may be disclosed in or on the public record

F. Even if no longer engaged in this proceeding, every person who has signed a Nondisclosure Certificate continues to be bound by the provisions of this Protective Order. The obligations under this Protective Order are not extinguished or nullified by entry of a final order in this case and are enforceable by the MPSC or a court of competent jurisdiction. To the extent Protected Material is not returned to a Disclosing Party, it remains subject to this Protective Order.

G. Members of the Commission, Commission staff assigned to assist the Commission with its deliberations, and the presiding hearing officer shall have access to all Protected Materialthat is submitted to the Commission under seal without the need to sign the Nondisclosure Certificate.

H. A Party retains the right to seek further restrictions on the dissemination of Protected Material to persons who have or may subsequently seek to intervene in this MPSC proceeding.

I. Nothing in this Protective Order precludes a Party from asserting a timely evidentiary objection to the proposed admission of Protected Material into the evidentiary recordfor this case.

III. PROCEDURES

A. The Disclosing Party shall mark any information that it considers confidential as "CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21193." Software executable files containing protected material may not be capable of being marked with the foregoing required protective language. The inability to mark software executablefiles containing protected material with such protective language shall not diminish the requirements of this Protective Order. It shall be sufficient if the medium used to deliver software executable files containing protected information is marked with the required protective language. However, any output from the software executable files containing protected material that is generated only as a reproducible document, whether electronic or non-electronic, that is capable of being marked with the required protective language, shall be marked by the party who generatedthe output with such protective language and subject to the requirements of this Protective Order. If the Receiving Party or a Reviewing Representative makes copies of any Protected Material, they shall conspicuously mark the copies as Protected Material. Notes of Protected Material shall also be conspicuously marked as Protected Material by the person making the notes.

B. If a Receiving Party wants to quote, refer to, or otherwise use Protected Material in pleadings, pre-filed testimony, exhibits, cross-examination, briefs, oral argument, comments, or in some other form in this proceeding (including administrative or judicial appeals), the Receiving Party shall do so consistent with procedures that will maintain the confidentiality of the Protected Material. For purposes of this Protective Order, the following procedures apply:

1. Written submissions using Protected Material shall be filed in a sealed record to be maintained by the MPSC's Docket Section, or by a court of competent jurisdiction, in envelopes clearly marked on the outside, "CONFIDENTIAL – SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-21193." Simultaneously, identical documents and materials, with the Protected Material redacted, shall be filed and disclosed the same way that evidence or briefs are usually filed;

2. Oral testimony, examination of witnesses, or argument about Protected Material shall be conducted on a separate record to be maintained by the MPSC's Docket Section or by a court of competent jurisdiction. These separate record proceedings shall be closed to all persons except those furnishing the Protected Material and persons who have executed a Nondisclosure Certificate (Attachment 1) or who are otherwise permitted to review Protected Material without such certificate subject to this Protective Order. The Receiving Party presenting the Protected Material during the course of the proceeding shall give the presiding officer or court sufficient notice to allow the presiding officer or court an opportunity to take measures to protect the confidentiality of the Protected Material; and

3. Copies of the documents filed with the MPSC that contain Protected Material, including the portions of the exhibits, transcripts, or briefs that refer to Protected Material, shall be marked or identified as, "CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN CASE NO. U-21193" and shall be maintained in a separate portion of the record under seal, segregated in the files of the Commission, and withheld from inspection by all persons except those furnishing the Protected Material and persons who have executed a Nondisclosure Certificate (Attachment 1) or who are otherwise permitted to review Protected Material without such certificate subject to this Protective Order.

C. The Protected Material subject to this Order shall be shielded from disclosure to the extent permitted by law. If any person files a Freedom of Information Act ("FOIA") request with the Commission seeking access to documents subject to this Order, then the Commission's Executive Secretary shall notify DTE Electric as soon as reasonably practicable and DTE Electric may take whatever legal actions it deems appropriate to protect the Protected Material from disclosure. If the Commission denies a claim of confidentiality, in whole or in part, then the Commission shall give notice to DTE Electric at least five (5) business days prior to the Commission's contemplated disclosure in response to the request. The notice shall briefly explain why DTE Electric's objections to disclosure were not sustained by the Commission. In the event that the FOIA requester commences suit against the Commission to compel disclosure of a document for which privilege is claimed, the Commission shall immediately notify DTE Electricof the suit. Termination of Protected Status

D. A Receiving Party reserves the right to challenge whether a document or information is Protected Material and whether this information can be withheld under this Protective Order. In response to a motion, the Commission or the presiding hearing officer in this case may revoke a document's protected status after notice and hearing. If the presiding hearing officer revokes a document's protected status, then the document loses its protected status after 14days unless a Party files an application for leave to appeal the ruling to the Commission within that time period. Any Party opposing the application for leave to appeal shall file an answer with the Commission no more than 14 days after the filing and service of the appeal. If an application is filed, then the information will continue to be protected from disclosure until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired.

E. If a document's protected status is challenged under Paragraph IV.A, the ReceivingParty challenging the protected status of the document shall explicitly state its reason for challenging the confidential designation. The Disclosing Party bears the burden of proving that the document should continue to be protected from disclosure.

IV. RETENTION OF DOCUMENTS

Protected Material remains the property of the Disclosing Party and only remains available to the Receiving Party until the time expires for petitions for rehearing of a final MPSC order in Case No. U-21193 or until the MPSC has ruled on all petitions for rehearing in this case (if any). However, an attorney for a Receiving Party who has signed a Nondisclosure Certificate and who is representing the Receiving Party in an appeal from an MPSC final order in this case may retain copies of Protected Material until either the time for appeal of the Commission's final order resolving the issue has expired under MCL 462.26 or, if the order is appealed, until judicial review is completed and the time to take further appeals has expired. On or before the time specified by the preceding sentences, the Receiving Party shall return to the Disclosing Party all Protected Material in its possession or in the possession of its Reviewing Representatives – including all copies and notes of Protected Material – or certify in writing to the Disclosing Party that the Protected Material has been destroyed.

V. LIMITATIONS AND DISCLOSURES

The provisions of this Protective Order do not apply to a particular document, or portion of a document, described in Paragraph II.A if a Receiving Party can demonstrate that it has been previously disclosed by the Disclosing Party on a non-confidential basis or meets the criteria set forth in Paragraphs I.B.1 through I.B.5. A Receiving Party intending to disclose information taken directly from materials identified as Protected Material must-before actually disclosing the information-do one of the following: (i) contact the Disclosing Party's counsel of record and obtainwritten permission to disclose the information, or (ii) challenge the confidential nature of the Protected Material and obtain a ruling under Paragraph IV that the information is not confidential and may be disclosed in or on the public record.

VI. REMEDIES

If a Receiving Party violates this Protective Order by improperly disclosing or using Protected Material, the Receiving Party shall take all necessary steps to remedy the improper disclosure or use. This includes immediately notifying the MPSC, the presiding hearing officer, and the Disclosing Party, in writing, of the identity of the person known or reasonably suspected to have obtained the Protected Material. A Party or person that violates this Protective Order remains subject to this paragraph regardless of whether the Disclosing Party could have discovered the violation earlier than it was discovered. This paragraph applies to both inadvertent and intentional violations. Nothing in this Protective Order limits the Disclosing

Party's rights and remedies, at law or in equity, against a Party or person using Protected Material in a manner not authorized by this Protective Order, including the right to obtain injunctive relief in a court of competent jurisdiction to prevent violations of this Protective Order.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

____

Administrative Law Judge

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY for	)	Case No. U-21193
approval of its Integrated Resource Plan	)	
pursuant to MCL 460.6t, and for other relief	)	

NONDISCLOSURE CERTIFICATE

By signing this Nondisclosure Certificate, I acknowledge that access to Protected Material is provided to me under the terms and restrictions of the Protective Order issued in Case No. U- 21193, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by the terms of the Protective Order. I understand that the substance of the Protected Material (as defined in the Protective Order), any notes from Protected Material, or any other form of information that copies or discloses Protected Material, shall be maintained as confidential and shall not be disclosed to anyone other than in accordance with the Protective Order or used for any purpose not permitted by the Protective Order. Upon Execution, this Nondisclosure Certificate shall supersede any prior "Confidentiality and Nondisclosure Agreement" the undersigned entered with DTE Electric in connection with this 2022 IRP.

Reviewing Representative

Date: _____________

Title: ____

Representing: ______________________________________

Printed Name: _____________________________________

Email address: _____________________________________

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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JOYCE E. LESLIE

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

A1. My name is Joyce E. Leslie, Director (she/her/hers). My business address is One Energy Plaza, Detroit, Michigan 48226. I am the Director of Business Planning and Development and 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 Central Michigan University with a Bachelor of Science Degree in Business Administration, Accounting, and a minor in Economics. I received my master's degree in Business Administration from the University of Michigan.

Q4. What work experience do you have?

A4. I began my career with Deloitte & Touche in the Auditing division as a Senior Auditor and worked there for two and a half years. I began working for MCN Energy Group, Inc. in 1996, as an accountant prior to its merger with DTE Energy. Over the years, I held a number of positions with increasing leadership responsibilities in areas that include Energy Trading, Enterprise Risk Management, Controller for Gas Financial Support, Investor Relations, Electric Strategy and Special Projects, and Business Planning and Development.

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Q5. Do you have any professional certifications?

A5. Yes, I do. I am a licensed Certified Public Accountant (CPA) within the State of Michigan, having earned my professional certification in 1995, while employed by Deloitte & Touche. I am also a Financial Risk Manager (FRM) and was certified in 2008 by the Global Association of Risk Professionals (GARP).

Q6. What is your current position and what are your current responsibilities?

A6. Currently, I am the Director of Business Planning and Development. In this role, I am responsible for Long-Term Generation Strategy, Integrated Resource Planning, Corporate Energy Forecasting, Electric Strategy and Special Projects and Transmission Optimization.

Q7. Have you been involved in any prior regulatory proceedings?

A7. Yes. I served as the witness representing the Business Planning and Development Organization for the DTE Electric 2019 general rate case U-20561. I have also served in support of other witnesses representing the Business Planning and Development Organization for the following cases:

Case No.	Description
U-20162	DTE Electric 2018 General Rate Case
U-20471	DTE Electric 2019 Integrated Resource Plan Filing
U-20561	DTE Electric 2019 General Rate Case

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<u>Purpose of Testimony</u>

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to provide an overview of the Company's Integrated Resource Plan (IRP) Filing. Specifically, my direct testimony will:

- Provide an overview of the proposed course of action (PCA) of the 2022 IRP;
- Provide an overview of this filing by introducing the other DTE Electric witnesses in this proceeding and the topics they address;
- Provide an overview of the statutory framework established under Section 6t of 2016 Public Act (PA) 341 or the Act, including the Michigan Public Service Commission (MPSC or Commission) orders in Case No. U-18418, regarding Michigan Integrated Resource Planning Parameters (MIRPP), and Case No. U-18461 regarding IRP Filing Requirements.
- Provide an overview of the Company's 2022 IRP, including the overall process used to develop the IRP, the capacity forecast, an overview of the scenarios, sensitivities, and assumptions used, modeling results, and the key benefits of the PCA;
- Discuss the process that DTE Electric used to engage our customers, communities, and other stakeholders;
- Describe how this filing meets the requirements established under Subsection 6t of the Act including Commission orders in Case Nos. U-18418 and U-18461;
- Discuss the plan to implement the PCA focusing on the first three years following approval of this IRP;

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- Recommend that the Commission approve the IRP and the PCA including pre-approval of associated costs, highlighting why the PCA represents the most reasonable and prudent option for the Company to meet its customers' future capacity and energy needs.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-1	DTE Electric IRP Application Requirements Cross Reference Table
A-1.1	DTE Electric Recommendations from Order No. 20417
A-1.2	DTE Electric PCA Cost Pre-Approval Summary
A-1.3	DTE Electric PCA Implementation Plan
A-1.4	DTE Electric Public Outreach Report
A-1.5	DTE Electric Alignment of Planning Objectives and IRP Criteria

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. How is your testimony organized?

A11. My testimony consists of the following eight parts:

Part I	Summary of the Proposed Course of Action (PCA)

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Q12. Who presents evidence in support of this IRP application?

A12. The Company presents its case through 19 witnesses, including myself, as described below (in alphabetical order).

Kevin L. Bilyeu provides an overview of DTE Electric's historical and current Energy Waste Reduction (EWR) programs and performance, forward-looking EWR assumptions and sensitivities used in the Company's IRP process, and describe the EWR levels considered in the IRP.

Shawn D. Burgdorf provides an overview of the Midcontinent Independent System Operator (MISO) and Michigan resource adequacy requirements and MISO's capacity market including the accreditation rules for demand response resources. In addition, Witness Burgdorf will describe the Planning Reserve Margin Requirements (PRMR) including an overview of the MISO Zone 7 capacity position for Planning Year 2022/23, forecasted positions for Planning Years 2023/24 thru 2027/28 and the Company's existing capacity resources including Power Purchase Agreements (PPAs) that the Company modeled as part of its IRP.

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He will also describe the Capacity Import Limit (CIL) and Effective Capacity Import Limit (ECIL), which impact the amount of capacity that can be imported into MISO Zone 7. Witness Burgdorf also discusses the ancillary service products that are currently compensated within the MISO market.

Kevin Carden supports the results of the reliability assessment (resource adequacy), effective load carrying capability ("ELCC") analysis, and flexibility assessment performed by Astrapé Consulting in support of DTE Electric Company's 2022 Integrated Resource Plan.

Rodrigo Cejas Goyanes provides support for the financial, cost, and operation assumptions for select resources utilized in the overall IRP modeling, including assumptions for the Inflation Reduction Act (IRA). Witness Cejas Goyanes will also support the levelized cost of energy (LCOE) calculation analysis, economic analysis of selected peaker units, and impact of the discount rate sensitivity analysis on the revenue requirement calculation.

Adella F. Crozier discusses the Company's position relative to determining the existence of a capacity need in the context of administering the Public Utilities Regulatory Policy Act of 1978 ("PURPA").

Keegan O. Farrell discusses DTE Electric's existing demand response (DR) portfolio current DR pilots; the DR inputs utilized in the Company's IRP process, and provides support the Company's capital cost pre-approval request for DR.

Vielka M. Hernandez discusses the Renewable Portfolio Standard (RPS) related to Michigan Public Act 342 of 2016, additional renewable energy goals, and the Company's Voluntary Green Pricing (VGP) program plans. She describes the National Renewable Energy Laboratory (NREL) classes used to develop the forecasts and assumptions used for purchasing energy from utility-scale renewable energy resources in the IRP. In addition, she discusses the Company's existing renewable energy generating assets and describes the renewable energy assumptions specific to utility-scale wind and solar resources utilized in the IRP process to forecast pricing and capacity factor data for new renewable energy builds. She also discusses the potential for the Company to request a Financial Compensation Mechanism (FCM) and describe the Company's 2022 request for proposal (RFP) for renewable energy resources.

Timothy J. Lepczyk describes the reasonableness of a FCM request and describes the appropriateness of the after tax weighted average cost of capital within the proposed incentive. Witness Lepczyk will also describe the appropriateness of recovering the remaining net book value (NBV) for the Monroe Power Plant and the Belle River Power Plant coal handling assets, as well as decommissioning costs by classifying them as a regulatory asset and recovering those assets through amortization in base rates.

Markus B. Leuker provides the Company's electric sales, maximum demand and system output forecast for the period 2023-2042. Witness Leuker will describe how the Company developed the forecast of electric sales, maximum demand and

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system output, and will support the reasonableness of the electric sales forecast DTE Electric used in this proceeding.

Shayla D. Manning describes the foundational overview and definitions for the IRP, the IRP modeling improvements, and the resource planning and modeling process the Company performed in support of its 2022 IRP. Witness Manning further describes and supports the capacity position demonstration, modeling inputs, scenarios and sensitivities used in the IRP optimization modeling. She also describes the IRP modeling tools, the Belle River and Monroe Power Plant retirement analysis and the IRP analysis results.

Barry J. Marietta discusses the scope and status of environmental regulations that impact the Company's existing power plants and the impacts of compliance options. In addition, Witness Marietta will provide a summary of the projected emissions of the IRP PCA, an assessment of the Company's Environmental Justice (EJ) screening, and results of the impact assessment including a health impact analysis.

Laura K. Mikulan describes certain steps included the overall planning and modeling process, the emerging technologies that were considered in the modeling, the risk analysis that was completed, and the integration of the analyses in support of DTE Electric's 2022 IRP. She also discusses the Company's plan to account for the carbon associated with the purchase and sale of energy and the inclusion of resource adequacy modeling in the IRP process. Witness Mikulan also provides details on the establishment of the effective load carrying capacity (ELCC) levels

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of solar and storage and the level of battery benefits modeled, a description of the build plans used in the transmission analysis, as well as the synthesis of the modeling results and risk assessment analyses used to determine the PCA.

Justin L. Morren describes the Company's fossil-fueled, nuclear, and energy storage assets in support of the 2022 IRP and the changes to the coal-fired retirement schedule in the PCA. Witness Morren also discusses the operation and maintenance (O&M) expenses and capital expenditures that were inputs to the retirement analysis for coal-fired power plants, the community and employee impacts of accelerated retirement scenarios, and the decisions to accelerate the retirement of the Monroe Power Plant and convert the Belle River Power Plant to a natural gas peaking resource. He will also summarize the peaker analyses being performed by the Company. Finally, Witness Morren will discuss future energy storage build included in the Company's PCA.

Grace N. Musonera discusses how distribution planning is coordinated with the Company's IRP, the Conservation Voltage Reduction (CVR) and Volt-Var Optimization (VVO) program including the assumptions used in the Company's IRP process and costs associated with CVR/VVO in the PCA. Witness Musonera will also discuss efforts to better align distribution and resource planning processes and distribution-related assumptions developed by Distribution Operations to support the IRP modeling, including estimates of avoided Transmission & Distribution (T&D) capacity values for the Company's EWR program and distribution costs associated with new resources. Finally, Witness Musonera discusses how peaking generation supports reliability on the distribution system and the role of Distribution Operations in the Company's peaker analysis.

Ryan C. Pratt describes the Company's current fuel procurement practices, supply arrangements, and costs associated with the Company's existing generating facilities as well as support the expected fuel costs associated with potential proposed or future supply resources. Witness Pratt will also discuss the fossil fuel price forecasts used in the Company's IRP process.

Sonjoy D. Roy describes the Company's engagement with the local transmission owner, International Transmission Company (ITC), in the Company's IRP process. This includes implications to the Michigan transmission system based on the different scenarios studied and how they were considered in the IRP process and PCA, including grid infrastructure needs and the associated costs. Witness Roy will also describe the Capacity Import Limit (CIL) analysis and the anticipated effects of fleet changes proposed in the Company's IRP to the import capability of the lower peninsula of Michigan. Witness Roy will describe additional transmission planning studies impacting the company's IRP.

Theresa M. Uzenski describes the regulatory asset accounting proposal and related amortization requested by the Company.

Aaron Willis provides an estimate of the impact on average customer rates of the PCA, which includes an analysis of rate impacts for the different customer segments.

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PART I: SUMMARY OF THE PROPOSED COURSE OF ACTION

Overview

Q13. Can you provide an overview of the Company's Proposed Course of Action (PCA)?

A13. DTE Electric continues to make progress on its decarbonization journey and transformation of the electric generation fleet that serves its 2.3 million customers in Southeast Michigan. While developing the 2022 IRP, the Company sought customer and stakeholder feedback and centered the plan on what was important based on that feedback: a PCA that provides reliable and affordable power from a diverse mix of cleaner energy resources including solar, wind, storage, and natural gas.

The Company's IRP builds on the foundation of the 2019 PCA continuing the growth and acceleration of cleaner energy resources and commitment to reducing energy waste. The 2022 IRP analysis covers a 20-year period (2023-2042) and results in a proposed PCA that includes the adoption of 15,400 MW of renewable energy and 1,810 MW of battery storage, the retirement 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 coal-fired to a natural gas peaking resource. The PCA results in an affordable, diversified energy mix that the Company's customers can rely on, and a cleaner environment for the families, communities, businesses, and the state of Michigan.

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In 2017, DTE Electric was one of the first electric utilities in the country to set decarbonization goals.[1] Since then, as shown in Table 1, DTE Electric has accelerated its carbon dioxide (CO_2) emissions goals, with this PCA marking the fourth update to these goals.

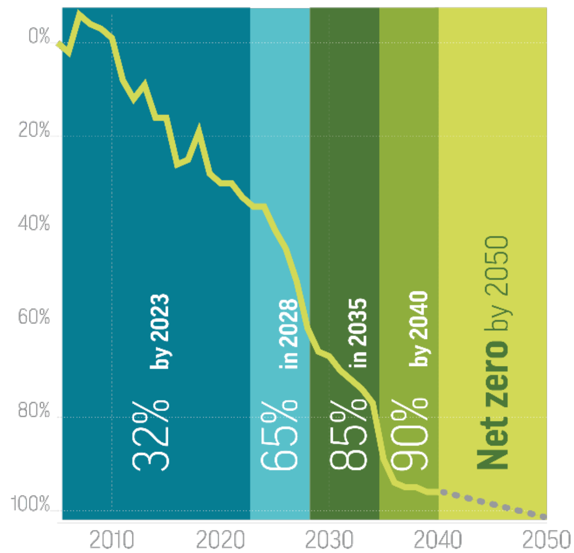
Table 1 - DTE Electric CO_2 Emission Reduction Goals

Announcement Year	2017 Goal	2019 Goal	2021 Goal	2022 Goal
Carbon Reduction Goals (compared to 2005 baseline)	- 30% by early 2020's - 45% by 2030 - 75% by 2040 - 80% by 2050	- 32% by 2023 - 50% by 2030 - 80% by 2040 - Net zero by 2050[2]	- 32% by 2023 - 50% by 2028 - 80% by 2040 - Net zero by 2050	- 32% by 2023 - 65% in 2028 - 85% in 2035 - 90% by 2040 - Net zero by 2050

The PCA meaningfully advances the Company's interim CO_2 emissions reduction goals by planning to achieve a 65% reduction in 2028, an 85% reduction in 2035, and a 90% reduction by 2040 from a 2005 baseline. Figure 1 shows the Company's CO_2 emissions reduction goals.

[1] Note that throughout IRP testimony, the Company may use "carbon" and "CO_2" interchangeably. The Company's use of "carbon" with respect to emissions reductions refers to CO_2 only.
[2] Net zero was announced in later 2019, after the 2019 IRP was filed

Figure 1 - CO_2 Emissions Reductions Goals



The PCA achieves a 90% carbon reduction goal by 2040 with a clear action plan and aggressive interim goals. DTE Electric remains committed to going as fast as it can to reach net zero emissions while maintaining reliability and affordability. The Company will continue to assess its decarbonization goals, just as it has done multiple times since it set its first goal in 2017.

Central to the Company's PCA is the full retirement of its coal-fired generation in 2035. DTE Electric has two coal-fired steam power plants remaining in its fleet:

- **Belle River Power Plant (Belle River)** is a 1,270 MW[3] baseload coal-fired power plant in St. Clair County, which has two units in total. DTE Electric is the majority owner of Belle River, owning 81.39% of the plant, with Michigan Public Power Agency (MPPA) owning 18.61%. In the 2019 PCA,

[3] Summer rated capacity.

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the Company announced the retirement of Belle River on coal by 2030. In October of 2021, DTE Electric accelerated the date to cease the use of coal as a fuel source to 2028. This updated timeline aligned compliance plans with the United States Environmental Protection Agency's (EPA) Effluent Limitation Guideline (ELG) rules. The PCA proposes converting Belle River to a natural gas-fired peaking resource[4] in 2025 and 2026 (Unit 1 and Unit 2, respectively). The converted plant will provide reliable generation for customers, especially when customer demand is higher (such as in high or peak summer heat) or when other supplies are unavailable to keep power supply reliable. The converted Belle River plant, expected to be fully retired by 2040, ensures electric reliability (resource adequacy and grid reliability) cost-effectively as the Company integrates thousands of megawatts of renewable energy generation and battery storage while accelerating the retirement of coal-fired generation.

- **Monroe Power Plant (Monroe)** is a 3,066 MW[5] coal-fired power plant located in Monroe County. Monroe, which has four units in total, is the fourth largest coal-fired power plant in the United States[6] and represents approximately 30% of the Company's generation energy mix. The retirement date for the Monroe Power Plant in the 2019 PCA was December 31, 2039. As described by Witnesses Mikulan and Roy in their testimonies, Monroe plays a critical role in providing baseload, reliable power to support

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[4] Belle River will operate as a peaking resource, "generating equipment normally operated only during the hours of highest daily, weekly, or seasonal loads."

[5] Summer rated capacity.

[6] Largest coal plants in the United States, Lustig, Michael. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/chartwatch-owners-of-8-of-10-largest-us-coal-plants-have-net-zero-targets-59942473. 24 August 2020, accessed October 18, 2022

Michigan's residents and businesses, and therefore supporting the overall Michigan economy. The 2022 PCA commences the phased retirement journey of Monroe in 2028 – nearly 12 years ahead of the previous plan – with the retirement of Units 3 (773 MW) and 4 (762 MW). This phased approach, that will continue to include collaboration with stakeholders and the community, concludes in 2035 with the retirement of Units 1 (758 MW) and 2 (773 MW), nearly five years ahead of the previous plan.

The conversion of the Belle River Power Plant to a natural gas peaking resource retains 1,270 MW of Midcontinent Independent System Operator (MISO) Zone 7[7] capacity and facilitates the early retirement of 1,535 MW of coal-fired resources, about half of Monroe, in 2028. The full retirement of coal in DTE Electric's portfolio in 2035 – retiring the last major coal plant in Michigan[8] – represents a truly transformational shift in the way the Company plans for, produces, and delivers electricity. The Company's coordination with the local transmission company, ITC, also indicated the Belle River conversion maintains electric grid reliability without having to invest in near-term transmission facility upgrades.

The Company's 2022 PCA for generation is transformational and is supported by a robust, comprehensive planning process that ensures continued reliable, cost-effective power for DTE Electric customers. As will be described throughout the

[7] All of Zone 7 is in the lower peninsula of Michigan, and nearly all of the lower peninsula is in Zone 7, with the exception of a small portion of southwest Michigan, which is included in PJM.

[8] The Company has been unable to confirm the expected retirement status of the remaining two known utility or municipally operated primary coal with gas facilities, Munising Power Plant and MSC Sebewaing. It is possible that non-utility (i.e., private industrial users) may also continue to operate coal facilities behind-the-meter in Michigan.

filing, the PCA ensures electric reliability, resource diversity, and flexibility to mitigate risks facing the energy industry. The PCA allows DTE Electric to time affordable, cost-competitive solar and energy storage projects early in the planning period in advance of initiating Monroe's phased retirement. The PCA lays out a path to meaningfully accelerate interim carbon emissions goals as the Company continues to make progress toward its net zero goal. The PCA also includes a placeholder for a low or zero carbon dispatchable resource slated in the mid-2030s supporting the retirement of the last two units at Monroe. The Company will continue to explore developments of emerging technologies in this fast-changing environment and evaluate options to fill this critical need for dispatchable generation in future IRPs.

PCA

Q14. Can you please describe the key components of the Company's PCA over the 20-year study period of 2023 through 2042?

A14. Yes. Over the 20-year study period, DTE Electric's PCA:

- Develops 6,500 MW of solar
- Develops 8,900 MW of wind
- Develops 1,810 MW of battery storage
- Ceases coal-fired generation operations at Belle River and converts it from a 1,270 coal-fired baseload power plant to a 1,270 MW natural gas peaking resource in 2025 (Unit 1) and 2026 (Unit 2). The converted Belle River peaking resource is expected to be retired by 2040

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- Retires Monroe Power Plant Units 3 and 4, a total of 1,535 MW of coal-fired generation in 2028 – nearly 12 years earlier than previously announced - and retires Units 1 and 2, 1,531 MW of coal-fired generation, in 2035 – nearly five years earlier than previously announced
- Incorporates the maximum amount of achievable EWR potential identified in the 2021 Michigan EWR Statewide Potential Study (Statewide Potential Study), an average of 1.5% per year over the study period
- Deploys 38 MW of conservation voltage reduction/volt-var optimization (CVR/VVO)
- Incorporates 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. While low or zero carbon dispatchable technologies to support net zero goals are still emerging and require further development, the technology currently selected in the IRP is a natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS).

The resources in the PCA are incremental to the investments currently approved in the Company's 2019 IRP (2019 IRP) or other regulatory filings that continue to be implemented (e.g., solar, demand response and CVR/VVO).

The Company is well positioned to implement the PCA having carefully considered the approach and sequencing of new investments and retirements, however, the Company cannot successfully implement the PCA by itself, without Commission approval of the proposals that make it possible. Thus, the IRP filing includes requests for approval of essential regulatory and financial proposals to support the successful implementation of the PCA, including the pre-approval of certain costs, regulatory asset treatment for the Monroe Power Plant and the coal handling assets at Belle River as well as decommissioning costs at both plants, and a proposed financial compensation mechanism applicable to power purchase agreements (PPAs).

The result of DTE Electric's PCA is a fully integrated proposal that ties the Company's decarbonization journey to the proposals described above and, in the testimonies, and exhibits filed in this proceeding. Therefore, any modification to, or rejection of, a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

<u>First five years of the PCA (2023-2027)</u>

Q15. Can you summarize the Company's PCA during the first five years from 2023 through 2027?

A15. Yes. The first five years of the Company's PCA includes the following:

- Renewables – 800 MW of solar
- Battery storage – 240 MW
- Belle River – retires the plant on coal and converts it to a 1,270 MW natural gas peaking resource, one unit at a time in 2025 and 2026

- EWR – 2% annual savings in 2023 and an average 1.6% annual savings for the first five-year period, consistent with the maximum amount of achievable potential as identified in the EWR 2021 Statewide Potential Study (EWR Statewide Potential Study)
- CVR/VVO – 15 MW

Implementation of the solar and storage resources and the conversion of Belle River to a natural gas peaking resource identified in the first five years of the PCA is necessary for the Company to proceed with the retirement of the first two units of Monroe Power Plant in 2028. In her testimony, Witness Mikulan explains why all these resources, together, must be in service prior to any retirement of Monroe units, to maintain reliability.

Second five years of the PCA (2028-2032)

Q16. What are the components of the PCA during the following five years, from 2028 through 2032?

A16. With the PCA's identified resources and financial mechanisms that I discuss later in my testimony in place by 2027, DTE Electric will be positioned to advance to the next phase of the PCA, from 2028-2032, which includes the following:

- Renewables
  - Solar – 3,600 MW
  - Wind – 1,000 MW
- Battery storage – 520 MW

- Monroe Units 3 and 4 retire in 2028 – 1,535 MW
- EWR – an average 1.2% annual savings, consistent with the maximum amount of achievable potential as identified in the EWR Statewide Potential Study
- CVR/VVO – 23 MW

The first 10 years (2023-2032) of the Company's PCA relies on known, commercially available technologies to ensure a reliable, flexible and affordable transition, laying the foundation for continued progress toward DTE Electric's net zero and the State's carbon neutrality goals.

<u>Last ten years of the PCA (2033-2042)</u>

Q17. What are the components of the PCA during the last ten years, from 2033 through 2042?

A17. The second half of the Company's PCA, from 2033-2042, includes the following:

- Renewables
  - Solar - 2,100 MW
  - Wind - 7,900 MW
- Battery storage – 1,050 MW
- Retirement of Monroe Units 1 and 2 in 2035 – 1,531 MW
- Belle River natural gas peaking resource retirement by 2040 – 1,270 MW
- Low or zero carbon dispatchable 946 MW placeholder resource in 2035; currently identified in this IRP as a CCGT with CCS

- EWR – an average 1.6% annual savings, consistent with the maximum amount of achievable potential as identified in the EWR Statewide Potential Study

While the first half of the 20-year proposal relies on known, commercially available technologies, we expect costs and available technologies will change before implementing the second half of the plan. While renewables, battery storage, and demand-side management programs will play a key role in the Company's transition towards cleaner energy through 2042, the resource and grid reliability impact of the final exit of coal will likely require the build-out of both a dispatchable resource to support electric reliability (resource adequacy and grid reliability) and grid infrastructure development to ensure a reliable transition. I will describe this further in Part V of my testimony, and Witnesses Mikulan and Roy will provide additional details in their testimonies. Both the advancement of emerging technology resources and the development of grid infrastructure require time, further planning, and development to fully retire Monroe (Units 1 and 2) and Belle River reliably and affordably.

The Company expects its overall supply mix will become increasingly reliant on intermittent resources during the study period (e.g., approximately 60% by 2042). This increased reliance on intermittent resources, when combined with the scale of the Belle River and Monroe Power Plants and their role in providing critical grid reliability functions, adds complexities to the development of solutions. The deployment of renewable energy at this scale in the 2030s will also require collaboration with many different communities to facilitate siting and permitting,

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improvements to the generation interconnection processes, and upgraded and/or new transmission facilities. The implementation of the PCA will also depend on the results of competitive procurement processes for new resources, as market conditions may vary from the assumptions used in the modeling and thereby affect timing and resource selection.

While the likely need for a dispatchable resource is identified in this PCA, low or zero carbon dispatchable technologies are not commercially viable today and will continue to evolve over time. Low or zero carbon dispatchable technologies may include CCGTs with CCS, small modular nuclear reactors (SMR or SMNR), and mid- to long-duration storage. As Witness Mikulan describes, the Company considers this a generic dispatchable resource pending further advancements in technology and commercial availability. DTE Electric anticipates the cost and commercial availability of emerging technologies will change, so the Company will also remain flexible and continue to evaluate emerging technologies in future IRPs.

Finally, in his testimony, Witness Roy details additional grid reliability challenges when the Belle River natural gas peaking resource is retired by 2040, further highlighting the need to continue to evaluate resource and reliability needs of the changing grid as technology, the industry, and plans evolve.

Q18. Is the Company including requests for financial mechanisms in this PCA?

A18. Yes. The transition of generation has far-reaching impacts and requires a level of certainty to support planning and implementation of investments so that the Company can serve its customers in an affordable and reliable manner. Due to the

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large-scale transformation proposed by DTE Electric in the PCA, the Company put forward three requests that are integral to the progression of the plan and which are discussed further in Part VI of my testimony.

- Cost pre-approval for approximately $135 million to support the conversion of Belle River Power Plant and $8.7 million for demand response to support the sustainment and growth of the programs as described in Exhibit 1.2. Witnesses Morren and Farrell support the pre-approval requests in their testimonies, including compliance with statutory criteria and the Commission's filing requirements based on the applicable project type.
- Regulatory asset treatment for the net book value (NBV) and decommissioning costs associated with Monroe Power Plant and the coal handling assets at the Belle River Power Plant; the regulatory asset would also include ongoing investments needed at Monroe to operate safely and reliably through retirement subject to prudence review in future proceedings.
- An update to the current financial compensation mechanism for PPAs as authorized under MCL 460.6t(15), and which would apply not just to VGP, but to all new or modified PPAs.

Approval of these requests as proposed would provide DTE Electric the certainty necessary to proceed with the implementation of the proposed generation transformation and progress its decarbonization plans affordably and reliably.

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Key benefits of the PCA

Q19. What are the key benefits of the PCA?

A19. The PCA provides a reliable, affordable path to decarbonization while creating long-term value for its customers and ensuring the Company's financial health through the generation transition. In summary, the key benefits include:

- Transforms DTE Electric's generation mix to cleaner, more diverse sources
  - Adds 15,400 MW of renewables and 1,810 MW of storage in Michigan by 2042
  - Ends the use of coal in 2035 with a responsible, phased retirement schedule protecting reliability and affordability
  - Redirects $2.4 billion from coal to cleaner sources of energy over the Base plan (also referred to as the "IRP starting point")[9]
  - Accelerates its previously announced carbon reduction goals, achieving a 65% reduction in 2028, 85% in 2035, 90% by 2040, and net zero by 2050
    - The plan's timelines are ahead of the timelines in the MI Healthy Climate Plan[10] and will help support Michigan's economy-wide

[9] The Base plan, also referred to "starting point" by witnesses, represents the status quo with Belle River retirement in 2028 and Monroe retiring year end 2039, along with approved renewable energy VGP and REP projects, maximum achievable potential for EWR based on the State Potential Study, and approved DR and CVR/VVO programs. Existing peaking facilities, Ludington, and Fermi continue to be operational throughout the study period. Witness Manning describes the starting point in more detail in her direct testimony; See WP JLM 08 - 2.4 Billion Redirected

[10] MI Healthy Climate Plan available at https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed October 17, 2022.

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greenhouse gas (GHG) emissions reductions interim goals of 28% by 2025 and 52% by 2030 from 2005 levels

  - Aligns with the Federal goals for the United States under the Paris Agreement to reduce US greenhouse gas emissions 50-52% below 2005 levels in 2030 and achieve a net zero emissions economy by 2050[11]

- Provides the highest generation diversity among alternative portfolios analyzed for risk, as described by Witness Mikulan, and aligns with customer feedback provided through the Voice of the Customer research, where respondents shared a broad acceptance of and desire for a diverse and balanced mix of resources

- Prioritizes reliability while preparing for its customers' needs
  - Incorporates results from resource adequacy and grid modeling into the IRP process, reducing risks to customers by having sufficient, local, and diverse energy and capacity resources
  - Leverages the converted Belle River Power Plant to support customers through periods of high customer demand and while DTE Electric integrates thousands of megawatts of renewables
  - Reduces near-term reliability risk associated with the need for substantial reactive power support (650 megavars) when both Belle River and Monroe retire

[11] White House National Climate Task Force: https://www.whitehouse.gov/climate/#:~:text=Reducing%20U.S.%20greenhouse%20gas%20emissions,clean%20energy%20to%20disadvantaged%20communities, accessed October 17, 2022.

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- Mitigates risks of relying on capacity markets that are subject to price volatility
- Supports increased customer adoption of transportation and building electrification
- Allows time for the commercialization of low and zero carbon dispatchable emerging technologies prior to the full retirement of the Monroe Power Plant

- Creates long-term value for its customers and communities
  - Positions the Company to take advantage of tax incentives and other benefits of the Inflation Reduction Act (IRA) of 2022, thereby supporting the affordability of the plan
  - Reduces the PCA-related revenue requirement impacts by 2.18% compound annual growth rate (CAGR), as well as the rate impacts compared to the Base Plan in place over the 20-year period
  - Saves $539 million net present value revenue requirement (NPVRR) in estimated future costs compared to the Base Plan
  - Projects $1.4 billion[12] in reduced future costs compared to the Company's 2019 plan
  - Preserves valuable interconnection rights and efficiently uses existing infrastructure in the proposed Belle River conversion from coal to natural gas; the Belle River conversion is one-sixth of the cost of a new

[12] See Witness Manning's WP SDM 158 - REFRESH Sensitivity Analysis Results

combustion turbine (CT), with the overnight capital costs of conversion being is ~$130/kW compared to a new CT at ~$800/kW

- Defers $350 million in transmission upgrades providing near-term savings to customers
- Drives about $9 billion of investment in clean energy over the next ten years, creating or retaining over 25,000 Michigan jobs, supporting the State's economy while reducing CO_2 emissions and maintaining reliable power
- Adopts the maximum amount of EWR levels achievable based on the findings of the MPSC Statewide Potential Study released in 2021, helping to defer the need for new generation while also helping eligible customers manage their energy bills
- Incorporates stakeholder feedback throughout the IRP process
- Maintains the Company's commitment to engaging coal plant communities to ensure a close partnership in advance of and during the transition period
- Plans to maintain the Company's no layoff commitment to employees. To deliver on this intention, the Company will work on several initiatives, including collaboration with union leadership and employees (both represented and non-represented), strategic workforce planning, workforce re-skilling, and employee redeployments

These benefits are discussed further in the testimony of Witnesses Mikulan, Manning, Morren, Roy, Bilyeu, Marietta, and Willis.

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Q20. Are there additional environmental benefits that result from this plan?

A20. Yes. In addition to the CO_2 emissions reductions stated above, the PCA drives expected additional emissions reductions including nearly a 100% reduction in sulfur dioxide and mercury emissions, 92% reduction in carbon monoxide emissions, 95% reduction in nitrogen oxide emissions, 72% reduction in particulate matter and 66% volatile organic compound emissions by 2042.[13]

PART II: STATUTORY AND REGULATORY FRAMEWORK FOR IRPs

Q21. What is the statutory and regulatory framework for IRPs?

A21. Rate-regulated electric utilities must file, no later than every five years, an integrated resource plan that "provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations and to meet the utility's requirements to provide generation reliability" (see Public Act 341 of 2016 (The Act), MCL 460.6t(3) and (20)).

The IRP filing must include the items specified in MCL 460.6t(5) such as a long-term load forecast, plans for meeting energy and capacity needs with cost estimates for all proposed construction and major investments, details on existing resources as well as plans for new generation, energy waste reduction, demand response, and electric transmission options, compliance with environmental regulations, and an analysis of rate impacts. In addition, the IRP must comply with the IRP modeling parameters and filing requirements established by the MPSC, and updated every five years, pursuant to MCL 460.6t(1).

[13] From 2023 baseline.

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Q22. What statutory criteria applies to IRPs?

A22. Section 6t of the Act requires the Commission to approve an IRP if it determines the plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To make this determination, the Commission shall consider whether the plan appropriately balances all the following factors:

- Resource adequacy and capacity enough in quantity to serve anticipated peak electric load plus applicable planning reserve margin (PRM) and local clearing requirement (LCR);
- Compliance with applicable state and federal environmental regulations;
- Competitive pricing;
- Reliability;
- Commodity price risks;
- Diversity of generation supply; and
- Whether the proposed levels of peak load reduction and EWR are reasonable and cost effective.

Q23. Are there other relevant statutory requirements?

A23. Yes, the Commission shall also make determinations on whether the IRP filing includes the elements for an IRP filing outlined in MCL 460.6t(5) and, to the extent practicable, the construction or investment in a new or existing capacity resource in the state is completed using Michigan workers.

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In addition, pursuant to MCL 460.6t(6), as interpreted by the Commission in its February 20, 2020 order at page 26, if the IRP includes new supply-side generation resources during the initial three-year planning period, the utility must issue a request for proposal (RFP) for such generation, use the results to inform the IRP, and include the RFP results in the IRP filing. This RFP provision is discussed in more detail later in my testimony and by Witness Hernandez in her testimony.

Q24. What are the MPSC's IRP filing requirements?

A24. In Case No. U-18461, the Commission approved requirements for the content of utility IRP filings. These filing requirements incorporate and augment the plan filing information required by statute in MCL 460.6t(5).

Q25. What are the MPSC's IRP modeling parameters?

A25. In its 2017 order in Case No. U-18418, the Commission approved the Michigan Integrated Resource Planning Parameters (MIRPP), which consist of a set of common scenarios, sensitivities, assumptions, and data sources to be used in IRP modeling. As discussed further in my direct testimony and the testimony of Witness Manning, the MIRPP directed utilities to model three scenarios and several sensitivities on each. A scenario is a view of the future based on broad market assumptions such as commodity prices, technology prices, national load growth, and environment regulations. A sensitivity is a case that is designed to test one specific uncertainty or variable which is applied to the scenarios.

Q26. When did DTE Electric last file an IRP?

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A26. DTE Electric last filed an IRP on March 29, 2019, in MPSC Case No. U-20471 and received the final order on April 15, 2020. The Company conducted the last IRP to meet the requirements set forth in MCL 460.6t, and the associated filing requirements contained in the December 20, 2017, MPSC order in Case No. U-18461.

Q27. Were there further expectations the Commission set based upon the 2019 IRP?

A27. In its April 15, 2020, order approving the 2019 IRP in Case No. U-20471, the Commission instructed DTE Electric to make certain changes in its next IRP. The Commission's 2020 order addressed its expectations on forecasting methods, various modeling assumptions and approaches, modeling software, transmission and import analyses, retirement analysis of Belle River, and community engagement in the Company's next IRP filing. A summary of these expectations and how they were addressed in this IRP filing is included in Exhibit A-1.1.

Q28. Have there been other MPSC orders providing guidance on IRPs and how were they addressed in this IRP?

A28. Yes. The Commission issued orders on February 18 and September 24, 2021, in Case No. U-20633 in response to the Governor's Executive Directive 2020-10, addressing GHG. The Company has provided one scenario as directed in Case No. U-20633 in addition to the Company developed scenarios and those required by the MIRPP as directed by the Commission. The new scenario maintains the high load growth sensitivity of 1.5% from the Environmental Policy scenario and requires that the Company demonstrate a 28% and 32% reduction in carbon emissions from their 2005 amounts by 2025. This information will be used to support the

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Department of Environment, Great Lakes and Energy's (EGLE) advisory opinion regarding the plan's compliance with environmental laws as set forth in MCL 460.6t(7).

Q29. Has the Commission addressed its intentions to better align distribution, transmission and resource planning?

A29. Yes, several Commission orders as part of its MI Power Grid initiative and the September 2019 State Energy Assessment address this topic (e.g., U-20464, September 11, 2019, order; October 17, 2019, order in U-20645; September 24, 2021, order in U-20633). The Commission also discussed the need for greater planning alignment in prior integrated resource plan cases, including DTE Electric's 2019 IRP in Case No. U-20471. Witnesses Roy and Musonera discuss the coordination of the IRP with transmission and distribution planning processes, respectively.

Q30. The MPSC is in the process of updating the IRP modeling parameters, filing requirements, and demand-side (EWR and DR) potential studies pursuant to MCL 460.6t(1). Do the proposed parameters, filing requirements, and studies apply to the Company's IRP filing?

A30. No. In Case Nos. U-18461, U-20633 and U-21219 (Case No. U-20633 et al), the MPSC has been updating the IRP Filing Requirements and MIRPP respectively, as set forth in MCL 460.6t(1). The MPSC also conducted new studies on DR and EWR potential to be reflected in IRP assumptions. MCL 460.6t(1) requires these updates every five years, and the new provisions and studies will apply to IRPs filed after 2022.

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Although not technically applicable to the Company's 2022 IRP, DTE Electric has been participating actively in this process and monitoring the development of new modeling parameters and filing requirements to be better prepared for the expectations of the MPSC and stakeholders as it developed its IRP.

Q31. While not required, does the Company's filing reflect changes being considered in Case No. U-20633 et al. for post-2022 IRPs to assist the MPSC and stakeholders in their review of the IRP and account for updated information such as the new EWR and DR potential studies?

A31. Yes, to the extent possible, the Company has reflected the new studies and filing requirements. The Company filed with the Commission a request to use the most up-to-date demand response and energy waste reduction potential studies published by the Commission in 2021 in this IRP. In its May 26, 2022, Order in the instant case, No. U-21193 on page 3, the Commission found that DTE Electric's request to use the 2021 EWR and DR Statewide Potential Studies rather than the 2017 EWR and DR Potential Studies was reasonable.

In addition, the Company has been closely monitoring the MPSC process to develop guidelines for environmental justice (EJ) analyses as part of the upcoming new IRP filing requirements. The MPSC Staff's draft guidelines were used to inform the Company's analyses as detailed by Witness Marietta in his testimony.

Q32. Is the application, along with witness testimony and exhibits, consistent with the filing requirements and instructions ordered in Case Nos. U-18418, U-

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18461, and U-20633 as well as the Company-specific instructions ordered in Case No. U- 20471?

A32. Yes. Please see Exhibit A-1 DTE Electric IRP Application Requirements Cross Reference Table.

PART III: IRP CONTEXT, PLANNING OBJECTIVES AND PROCESS

IRP Context

Q33. Can you describe the key components of the Company's last IRP (2019 IRP), that the Commission approved on April 15, 2020, in Case No. 20471?

A33. Yes. The IRP approved by the Commission included the following PCA that reduced the Company's reliance on coal and increased renewable energy and demand-side resources:

- Coal retirements (summer capacity rating MW):
    - River Rouge Unit 3 (272 MW) – 2022
    - St. Clair Units 2, 3, 6 and 7 (1,065 MW) – 2022
    - Trenton Channel Unit 9 (495 MW) – 2022
    - Belle River (1,270 MW[14]) – 2029/2030
    - Monroe (3,066 MW) – 2039
- Demand-side Programs:
    - EWR at 1.75% in 2020 (prorated based on date of order) and 2% in 2021
    - DR increasing from 709 MW in 2019 to 859 MW in 2024

[14] Represents total capacity, DTE Electric's capacity is 1,034 MW.

- CVR/VVO pilot in 2020 with scaling to 50 MW by 2030

- Renewable Energy investments:
  - PA 342 15% Renewable Portfolio Standard (RPS) - 1,667 MW
  - Voluntary green pricing (VGP) program (MIGreenPower) - 1,391 MW

Q34. Has the Company successfully implemented the 2019 IRP?

A34. Yes. The Company has successfully implemented the 2019 IRP that the Commission approved in 2020. This included power plant retirements as well as new cleaner energy investments that enhance the diversity of its electricity supplies. The Company has filed regular updates on its IRP implementation in Case No. U-20471. Specific actions implemented include:

- Retirement of a combined 1,832 MW of coal-fired power plants at St. Clair,[15] Trenton Channel,[16] and River Rouge, including River Rouge retiring one year earlier than expected in 2021 instead of 2022; this was done as part the Company's Retire with PRIDE (People, Respect, Integrity, Dignity, and Engagement) initiative, which I will describe briefly later in testimony, and in collaboration with impacted communities and employees
- Achievement of 1.67% EWR in 2020 (prorated based on 1.75%), 2% in 2021, on track to achieve 2% in 2022, and expected execution of 2% in 2023

[15] The St. Clair and Trenton Channel plants were placed in suspension in June of 2022, have not run since then, and will officially retire by December 31, 2022.

- Achievement of 834 MW[16] in 2021 related to DR programs and on track to reach 929 MWs in 2024 and 949 MWs in 2026[17], exceeding the goal of 859 MW by 2024 established in the 2019 PCA
- Implementation of the CVR/VVO pilot to test the application of technologies to cut energy waste in the electric delivery system
- Accelerated the retirement of Belle River Power Plant on coal two years earlier than planned to 2028
- Completed the construction of DTE Electric's Bluewater Energy Center[18] (BWEC), a 1,127 MW state-of-the-art combined-cycle natural gas plant placed into commercial service in June 2022. BWEC helps meet energy and capacity needs with the retirement of the St. Clair, Trenton Channel, and River Rouge Power Plants and keeps the grid stable to balance fluctuations in load and renewable energy output
- Invested in new renewable energy projects, including:
    - Four new DTE Electric owned renewable projects, to support the Company's compliance with the 15% RPS. The Pine River Wind Farm (161 MW) came online in 2019, Polaris Wind Farm (169 MW) came online in 2020, Ford Rooftop Solar (750 kW) came online in 2021 and the Meridian Wind Farm (225 MW), which is scheduled to be operational this year
    - Executed 456 MW of wind (Isabella 1 and 2 Wind Farms (384 MW) and Fairbanks Wind Farm (72 MW)) and 79 MW of solar (Assembly Solar)

[16] MWs shown in UCAP
[17] 2021 Capacity Demonstration Case No. U-21099
[18] This facility was approved by the Commission in 2018 in Case No. 18419 through the certificate of necessity (CON) process pursuant to MCL 460.6s.

projects to support MIGreenPower. MIGreenPower allows customers to enroll up to 85% of their monthly electric usage from renewable energy. MIGreenPower has grown to become one of the largest green pricing programs in the nation. Additional generation to support the program's expansion was approved in the Company's renewables Case No. U-20851. Additional generation is also being addressed to support the program's expansion in the Company's pending renewables Case No. U-21285.

- Increased the capacity at the Ludington Pumped Storage facility, co-owned by DTE Electric and Consumers Energy, by 204 MW (DTE Electric's share). This project was completed in April 2022. Ludington is a critical energy storage asset in Michigan and can help balance increased levels of intermittent generation and address other supply-demand fluctuations.

The 2019 IRP accelerated the retirement of three coal fired power plants, River Rouge, Trenton Channel, and St. Clair, and incorporated renewables, natural gas, and demand-side management to further diversify the Company's generation mix. The 2019 PCA set updated CO_2 emissions reduction goals and established a path to maintain reliable, affordable power. The 2022 PCA continues that trajectory, further accelerating the Company's CO_2 reduction goals for the fourth time as shown in Table 1, accelerating coal plant retirement schedules, and integrating additional cleaner generation sources.

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Industry Changes

Q35. What has changed in the utility industry since DTE Electric filed its last IRP in 2019?

A35. There are several factors that have been affecting the electric utility industry since the Company filed its last IRP in 2019. Broadly speaking, these include: 1) electric reliability including capacity markets, 2) state and federal regulatory policies on climate and the environment, 3) supply chain constraints, 4) customer feedback, and 5) investor sentiment. These factors and how the Company considered them in its IRP planning process are discussed further below. Witnesses Manning (modeling), Mikulan (risk assessment), Marietta (environmental regulations) and Hernandez (supply chains) also address some of the potential emerging issues identified here. As the electric utility industry continues to evolve and adapt to the changing environment, ongoing reliability planning, and continued collaboration will be important.

Q36. What factors have impacted electric reliability and regional planning?

A36. The combination of dispatchable plant retirements, including coal and nuclear, and delays in bringing new intermittent resources online has played a role in reducing reserve margins throughout the MISO footprint. Lower reserve margins have meant an increase in the occurrence of emergency declarations across the MISO footprint and have highlighted the need for careful resource adequacy planning.[19] As Witness Burgdorf explains, such resource adequacy concerns were brought to

[19] Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct available at https://cdn.misoenergy.org/2021-11-30_RAN%20Seasonal%20Construct%20and%20Availability%20based%20accreditation608310.pdf, see pp 1142-1143, accessed October 17, 2022.

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the forefront with the recent results of the MISO 2022-23 Planning Resource Auction, in which MISO North-Central fell short of capacity obligations, and, therefore, did not meet federal reliability requirements. In addition, utilities in neighboring states have announced delays in the planned retirement dates of several power plants in response to recent market conditions[20] and MISO's presentation to the Resource Adequacy Subcommittee[21] projects that 2030 may be an inflection point in terms of generation retirements and the need for replacement resources in the MISO region. In alignment with the Company's "Reliable and Resilient" planning objective, DTE Electric expanded the scope of reliability modeling to include a resource adequacy analysis in this IRP. In doing so, the Company can ensure sufficient energy supply is available for customers, even amid market changes. I will describe the planning objectives and the approach to reliability analysis later in my testimony. Witnesses Mikulan and Carden describe the resource adequacy modeling in more detail in their testimonies.

Q37. Did the Company consider the factors that have impacted electric reliability and regional planning in the IRP process and in the PCA?

A37. Yes. The IRP considers trends related to resource adequacy and the broader regional market and supply outlook with increased retirement of thermal generation across MISO and beyond. First, in the development of the PCA, the Company included a robust approach to analyze resource adequacy and grid reliability

[20] Examples include Wisconsin Energy Company's Oak Creek 1,100 MW plant, Alliant's 415 MW Edgewater and 1,160 MW Columbia plants, and NiSource's (NIPSCO) 877 MW R.M. Schahfer plant.

[21] MISO, 2022 Regional Resource Assessment, Presentation to the Resource Adequacy Subcommittee, August 24, 2022, p 14-15, available at: https://cdn.misoenergy.org/20220824%20RASC%20Item%2006%20Regional%20Resource%20Assessment%20Presentation626035.pdf, accessed October 17, 2022.

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associated with the Company's changing resource mix. Second, DTE Electric designed the PCA to ensure resources are implemented in advance of major unit retirements and to allow time for the new resource mix to be operational. The tightening of capacity resources across the region with continued power plant retirements in the latter part of this decade reinforce the PCA approach to arrange the necessary capacity and energy to ensure DTE Electric can meet the needs of its customers reliably and affordability without exposing customers to reliability and market risks. Third, the IRP modeling update to capture the IRA tax credits also included updates for higher natural gas prices and wholesale electricity prices. Finally, the PCA proactively considers the role of transmission in the retirement of coal generation and addition of new resources as well as the effect of MISO's Long-Range Transmission Plan on ITC transmission's analysis for the IRP. Witnesses Mikulan, Roy, and Burgdorf address these topics in more detail in their testimonies.

Q38. Have there been any recent state and/or federal regulatory policy developments that relate to the IRP?

A38. Yes. In developing the IRP process, the Company considered a series of proclamations and public policies at the federal and state levels related to clean energy and climate change that have occurred over the past several years.

At the state level, in 2020, Governor Gretchen Whitmer signed Executive Directive 2020-10,[22] committing Michigan to a goal of achieving economy-wide carbon neutrality no later than 2050. Pursuant to this commitment, EGLE developed the

[22] Executive Directive 2020-10: Executive Directive 2020 - 10 (michigan.gov), available at: https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10 accessed October 17, 2022.

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MI Healthy Climate Plan.[23] The goals set by the plan call for a reduction in economy-wide GHG emissions in Michigan to 28% below 2005 levels by 2025, 52% by 2030, and to achieve carbon neutrality by 2050. The timelines set forth in DTE Electric's plan are ahead of the emission reduction timelines in the MI Healthy Climate Plan and will help support Michigan's economy-wide GHG emissions reductions interim goals.

At the federal level, President Biden rejoined the Paris Agreement. In April 2021, President Biden announced a new target for the United States to achieve a 50-52% reduction from 2005 levels in economy-wide net GHG pollution by 2030.[24] The Biden Administration also established a target for carbon-free electricity by 2035 and a net zero economy no later than 2050[25]. The Biden Administration has undertaken numerous policies, funding, and programmatic changes through the Department of Energy and other federal agencies to promote economy-wide decarbonization, including research and development of clean energy technologies such as long-duration energy storage, hydrogen, and carbon capture and sequestration. The Bipartisan Infrastructure Law (BIL), or the Infrastructure Investments and Jobs Act (IIJA), enacted into law in 2021, increased funding for clean energy investments. In August 2022, the IRA was enacted into law and

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[23] MI Healthy Climate Plan: https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed October 17, 2022.

[24] FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/, accessed October 18, 2022

[25] FACT SHEET: President Biden Renews U.S. Leadership on World Stage at U.N. Climate Conference(COP26) available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/11/01/fact-sheet-president-biden-renews-u-s-leadership-on-world-stage-at-u-n-climate-conference-cop26/, accessed October 17, 2022.

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includes incentives for energy storage, renewable energy, domestic clean energy manufacturing and minerals extraction and processing, electric vehicles and charging infrastructure, building electrification, energy efficiency, hydrogen, carbon capture and sequestration, nuclear, and other clean energy investments. Environmental rules and regulations also play an important role in resource planning. On October 13, 2020, the US Environmental Protection Agency (EPA) finalized the Effluent Limit Guidelines (ELG) Reconsideration Rule, which revised some requirements from the 2015 version of the ELG rule. The EPA's ELGs regulate how electric utilities must manage certain wastewaters. The Reconsideration Rule provides opportunities for utilities to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in a cost-effective manner. See Witness Marietta's testimony for further discussion of the ELG Reconsideration Rule.

Q39. Can you briefly describe the IRA?

A39. The IRA, enacted into law on August 16, 2022, includes approximately $370 billion in funding and tax incentives for clean energy investments and climate change mitigation and adaptation. The IRA is multi-faceted and introduces a multitude of incentive options for clean energy resources, including potential incentive adders based on other factors such as siting specifics and domestic content requirements. The IRA is intended to incentivize investments by energy and utility companies and the energy sector as a whole. Some of the key provisions include:

- New or revised tax credits for solar, wind, battery storage, hydrogen, nuclear, and carbon sequestration.

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- Rebates, tax credits, and other funding to promote customer adoption of energy efficiency, electric vehicles and charging infrastructure, and building electrification; and
- Expansion and increased funding for US Department of Energy loan guarantee programs addressing emerging technologies and other initiatives.

The IRA is expected to reduce the cost of renewable energy and other technologies that reduce GHG emissions.

Witnesses Cejas Goyanes, Manning, Mikulan, and I discuss in the respective testimonies how the Company, given timing of the IRA enactment shortly before filing this IRP, addressed some of the estimated impacts of the IRA on input assumptions, additional modeling that was performed, and adjustments to the PCA based on this modeling. The IRA is complex and there are many elements that will be addressed through guidance by various federal agencies, including but not limited to, the Department of Energy, Department of Treasury, Internal Revenue Service, and the Environmental Protection Agency. The provisions and implications of the IRA will be revisited in future IRPs.

Q40. Did the Company consider these policy trends in the IRP process and when determining the PCA?

A40. Yes. The Company continues to monitor developments on public policy changes. DTE Electric took a number of steps to factor these trends into the IRP modeling analysis and the PCA approach. This includes several notable aspects.

The estimated CO_2 emission reduction timelines under the PCA are ahead of the GHG reduction timelines set forth by Governor Whitmer's Executive Directive 2020-10 and are aligned with the federal GHG reduction targets.

The IRA was passed in August of 2022, well into the IRP modeling process. The Company moved quickly to begin to understand the implications of the IRA on the IRP even though the law is still very new and additional guidance on certain provisions will be forthcoming[26]. Specifically, the Company analyzed a new scenario to assess the impacts of the tax credit provisions for renewable energy, energy storage, nuclear, and CCS. This refresh of certain IRP modeling runs also updated gas prices and related wholesale electricity price inputs based on recent market trends. These modeling updates and the results are discussed further by Witnesses Mikulan and Manning in their testimonies. They suggest the IRA will further enhance the affordability of the PCA prior to its application as well as relative to the 2019 IRP based on this initial analysis of tax credit provisions. The Company recognizes that there are other IRA provisions, such as new rebate programs and incentives for energy efficiency and electrification that could affect long-term resource planning. In addition, there is uncertainty with respect to customer adoption levels based on the IRA provisions, as discussed by Witnesses Leuker and Bilyeu in their testimonies. However, the scenarios and sensitivities presented as part of the IRP account for a varying set of assumptions related to renewable energy, market prices, load forecasts, and EWR. Additionally, the PCA

[26] IRA implementation, See, e.g., U.S. Department of Treasury October 5, 2022 notices seeking comments on the implementation of certain provisions, such as the domestic content, energy community and low-income community designations, and transferability of credits. Available at: https://www.irs.gov/newsroom/irs-asks-for-comments-on-upcoming-energy-guidance, accessed October 21, 2022

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includes projected amounts of wind, solar, and battery storage that could be affected by the market's response to the IRA and other factors, such as siting, interconnection, and supply chains as discussed by Witness Hernandez in her testimony, leading to differences between modeled assumptions of the IRA impacts and actual market conditions over time. The Company's request for proposal (RFP) processes to procure new resources to implement this IRP will allow the Company to consider all sources, and thereby take advantage of any market-driven cost advantages of technologies and associated savings for customers. Thus, there will be variability in terms of the types of renewable resources that are ultimately developed. Witness Hernandez also discusses this procurement process in more detail in her testimony.

Q41. What is the nature of the supply chain disruptions affecting the electric utility industry?

A41. As a result of the COVID-19 pandemic and other factors, there have been disruptions in supply chains, logistics, and the workforce affecting numerous products. Notably, the solar photovoltaic (PV) industry has recently faced disruptions on a global scale with supply chain constraints and international trade actions affecting the availability of solar panel modules being imported into the US. Please refer to the testimony of Witness Hernandez for details.

Q42. Did the Company consider the supply chain challenges in the IRP process and when determining the PCA?

A42. Yes. With respect to supply chain issues that could affect the availability of new resources, the PCA provides for a phased implementation of new solar and other

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resources leading up to, and following, the retirement of the first two units at Monroe. The PCA lays out a long-term, phased plan for integrating new resources. In the near-term, integration of solar and storage resources from 2025-2027, combined with the use of Belle River as a reliability resource, will support the retirement of the first two units at Monroe in 2028. The addition of these resources in advance of the first two units of Monroe's retirement also ensures resource adequacy amid uncertain industry conditions that could affect the timing and cost of new resources in any given year, such as supply chain constraints, interconnection delays, or siting issues. While the PCA proposes a timeline for integrating new resources, it is important to recognize the need for flexibility in the timing of their deployments given the potential for changing market supply and demand conditions and factors that can affect competitive pricing, such as solar module and other equipment availability as discussed above. Again, the RFP process for new resource procurement will facilitate the Company's ability to respond to market conditions, which continue to evolve rapidly, to bring competitive outcomes for customers.

Q43. What are you hearing from customers?

A43. As I detail in Part IV of my testimony and in the DTE Electric Public Outreach Report, Exhibit A-1.4, the public comments received and the results of the Voice of the Customer research indicate that customers would like to see the Company transition to a more diverse, balanced, and cleaner generation portfolio. This includes customer support for an increased role for renewables in the clean energy transition. Another key theme the Company heard from customers is a desire for

DTE Electric to accelerate its decarbonization journey through the early retirement of coal-fired power plants and addition of zero carbon resources.

Q44. How is investor sentiment changing?

A44. The investor community has increased its focus on environmental, social and governance (ESG) factors. ESG investing involves the consideration of one or more ESG factors. Different investments may weigh ESG factors differently and may also focus on different specific criteria within a factor. As electric companies continue to transform the generation portfolio, it is foreseeable that utility investors' criteria will also evolve to focus on utilities with a cleaner generation mix. For example, Robeco Institutional Asset Management has exclusions related to coal expansion plans.[27]

Q45. Did the Company consider customer and investor trends in the IRP?

A45. Yes. The Company continues to monitor developments related to customer and investor perspectives. With respect to the consideration of customer perspectives, see Part IV of my testimony for discussion of how DTE Electric considered such input as part of the IRP process and Witness Mikulan's testimony for consideration of stakeholder feedback in the development of the PCA. As discussed above, the move to increased renewable energy and diversification of resources in the PCA are also reflective of the increased attention by investors to ESG.

Q46. Why is the Company filing an IRP a year earlier than required by Commission order?

[27] Exclusion Policy Robeco – July 2022 available at https://www.robeco.com/docm/docu-exclusion-policy.pdf, accessed October 18, 2022

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A46. The IRP process provides an opportunity for engagement and data-driven modeling and analyses to make informed decisions on how to meet the energy and capacity needs of the Company's customers. In addition to responding to the fast-changing environment in which DTE Electric operates, as discussed above, DTE Electric decided to move ahead with an IRP one year earlier than required by the Commission's April 2020 IRP order (Case No. U-20471) as it took action to comply with the EPA's ELG rules in October 2021 and consider options to retire its remaining coal units, Belle River and Monroe earlier than previously planned. The decisions related to these retirements and the continued operation of Belle River using natural gas are interconnected, given the need to continue to support electric reliability. Accordingly, DTE Electric believes now is the appropriate time to work with the Commission and stakeholders through a comprehensive, transparent planning process to evaluate the Company's resource plans. The acceleration of the filing will also provide greater certainty for DTE Electric, as well as its employees, customers, and the communities it serves, to support the implementation of changes, including plant retirements, in a responsible manner.

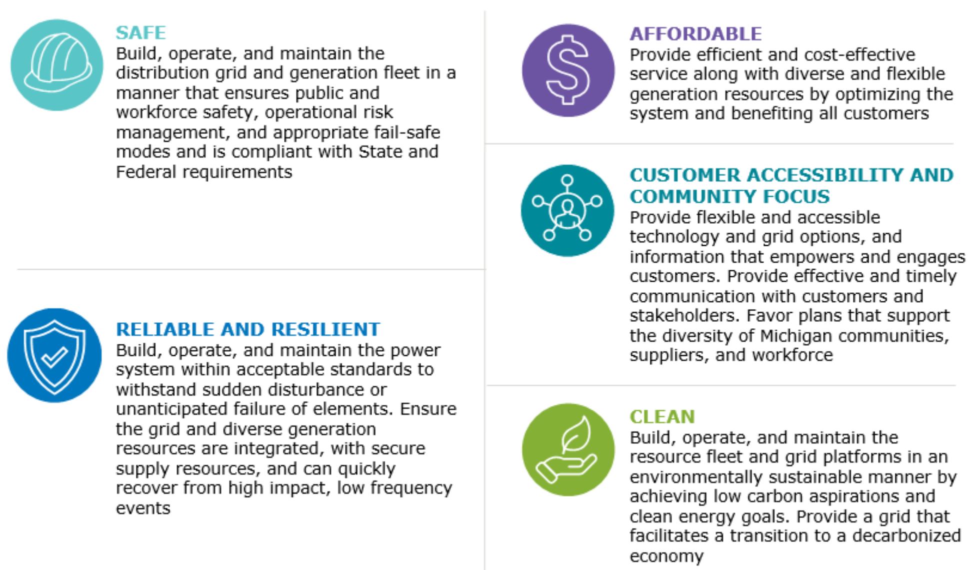
<u>Planning Objectives</u>

Q47. What planning objectives guided the Company's IRP development?

A47. The IRP customer focused planning objectives are based on the factors the Company has historically considered in making resource decisions and were formally documented when the Company was developing the 2017 Certificate of Necessity and 2019 IRP. DTE Electric updated the planning objectives in 2021 building on the planning principles that it used to guide the 2019 IRP. The current planning objectives were refined cross-functionally with the Company's

Distribution Operations team and updates were made to standardize the wording to be applicable across both generation and distribution planning and include a Customer Accessibility and Community Focus as a planning objective. The planning objectives are used to guide decision-making, including the development of this IRP as well as the Company's 2021 and future Distribution Grid Plans. The planning objectives are: Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean, as further described in Figure 2.

Figure 2 - Planning Objectives



Q48. How does the Company apply the planning objectives to the IRP process?

A48. The IRP process requires electric utilities to seek the most reasonable and prudent means of meeting customers' short and long-term energy and capacity needs. To do this, the Company defined a plan that best meets the planning objectives and statutory requirements, while also considering areas of importance expressed by stakeholders. The planning objectives were applied at various stages in the IRP

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process. For example, the Company considered the "Clean" planning objective when updating its carbon emissions goals. As discussed by Witness Mikulan in her testimony, the Company developed a robust plan that performed well using the planning objectives. While some portfolios may perform better on an individual planning objective, the Company sought to optimize a portfolio that balanced all the planning objectives.

IRP Process

Q49. Can you please describe the Company's approach and process to create the IRP?

A49. Yes. At the highest level, as shown in Figure 3, the IRP model considers various combinations of existing resources paired with new alternative resources to determine potential generation paths that meet customer energy needs.

Figure 3 - High Level IRP Model Approach

The model is solving the "equation," first, looking at customer needs – both today and how these needs could evolve over time; that is, how will residential,

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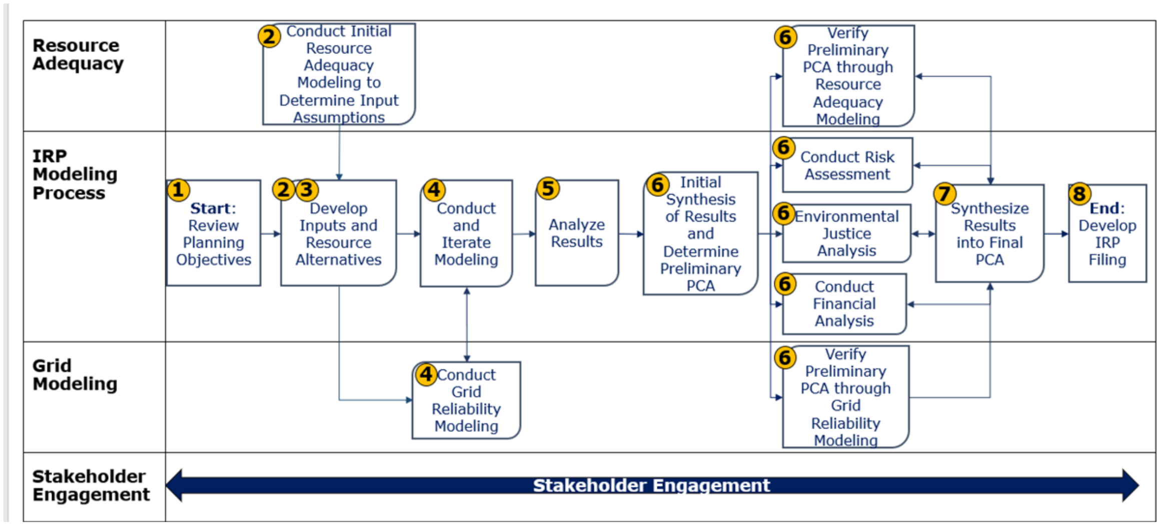
commercial and industrial customers' electricity usage change. Then the model looks at existing resources to determine if those resources can meet customers' needs. This step also includes looking at alternative retirement dates for existing coal plants. The model will answer the question of which alternative resources, if any, are needed to add to the remaining existing resources in a manner that meets customers' needs reliably and cost-effectively. Alternatives may include resources that are commercially available today, like solar and wind, as well as emerging resources that may be expensive or not fully ready for deployment today, although may be economic in 5, 10, or 15 years, such as various longer-duration storage technologies, CCGT with CCS, or SMRs.

Various scenarios, or views of the future based on broad market assumptions, and sensitivities, or changes to just one or a small number of variables in a scenario, are modeled as part of this process to consider new resource alternatives. 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.

Q50. Can you please describe the Company's process to create the IRP?

A50. There are numerous steps involved in developing an IRP. Figure 4 shows a high-level version of the Company's IRP process.

Figure 4 - IRP Process Overview



- The first step is to review the IRP Planning Objectives and compliance requirements.

- Steps two and three include gathering and developing inputs and assumptions and developing resource alternatives for use in the model. As part of these steps, the Company determines a broad set of scenarios and sensitivities that capture a wide range of potential futures and include the scenarios and sensitivities required by the MIRPP. This step also looks at the existing and approved resources, including known or projected changes, subtracting from it the sum of the customer demand forecast plus planning reserve margin (PRM).[28] The resultant difference would either be a projected capacity surplus or shortfall. To develop a reasonable and prudent plan, it is important to consider all feasible resource options to meet

[28] This is the precent by which resources must exceed load so that MISO will have the total resources required to meet load reliably throughout the year. MISO's planning reserve target, or loss of load expectation, is 1 day in 10 years. See, e.g. 2022/23 PY Planning Reserve Margin and Local Reliability Requirement – Draft Results, MISO, September 7, 2021, available at https://cdn.misoenergy.org/20210907%20LOLEWG%20Item%2003%20PY%202022-23%20Preliminary%20LOLE%20Study%20Results586120.pdf, accessed October 18, 2022.

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customer demand. The IRP process evaluates a multitude of technologies. These technologies are considered "alternatives." During steps two and three, the Company held eight public open houses as well as several technical workshops, one of which included the development of a scenario in conjunction with stakeholders.

- With the inputs, assumptions, alternatives, scenarios and sensitivities, and capacity outlook determined, the IRP 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 optimization modeling, Resource Adequacy modeling and Grid Reliability modeling. The IRP optimization 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 this IRP, under the various scenarios and sensitivities, the modeling team completed over 100 EnCompass runs. This step also involves transmission studies by ITC.
- In step five, DTE Electric analyzes the modeling results. Alterative portfolios under certain scenarios could then be compared to each other and conclusions drawn to help design the PCA. During this time (steps four and five) the Company held two additional technical workshops.
- Step six involves the initial synthesis of results, which supports the determination of a preliminary PCA. The preliminary PCA is then further

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analyzed through a series of additional studies, including resource adequacy modeling, risk assessments, environmental justice analysis, and financial analysis. ITC also provided verification of the preliminary PCA through grid reliability modeling. 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.

- In step 7, Results are then synthesized into what becomes the final 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.
- Lastly, DTE Electric develops the IRP filing, files an application and supporting testimony requesting the MPSC's approval of the IRP. Per MCL 460.6t, the MPSC will conduct a contested case proceeding with an initial decision within 300 days and its final decision within 360 days of the filing.

Stakeholder engagement underpins the IRP analysis and development process, which I discuss further in Part IV of my testimony. Refer to Witnesses Mikulan, Cejas Goyanes, and Manning's testimony for additional detail on certain steps within the IRP process.

Q51. Can you describe what types of modeling and analyses DTE Electric conducted to support this IRP?

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A51. 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") (Figure 3 above provides a high-level overview of the IRP modeling process); 2) transmission grid reliability and power flow studies through coordination with 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) and effective load carrying capacity (ELCC) (studying the contribution of particular resources such as solar and battery storage to help meet peak demand); 4) engineering studies on peaking generation (as discussed by Witness Morren in his testimony), 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. In her testimony, Witness Mikulan provides additional detail on the types of modeling performed in the IRP including the supporting Witness for each model or study.

While the capacity expansion 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 a PCA given transmission and resource adequacy impacts. The Company looked across multiple modeling runs to identify a 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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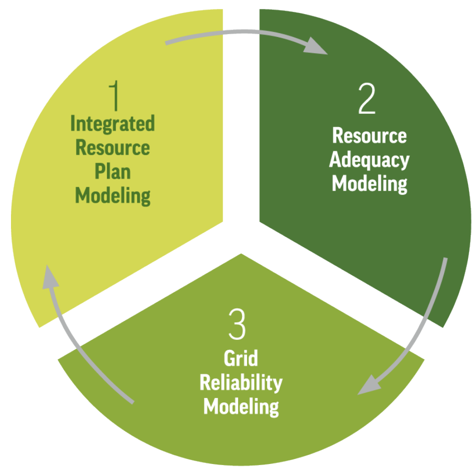
Q52. Can you describe DTE Electric's approach to ensuring electric reliability in the PCA?

A52. Yes. The PCA is designed to ensure DTE Electric can retire coal and incorporate large amounts of new resources while maintaining electric reliability. Reliability is the highest priority in the Company's planning process and the foundation of the PCA. DTE Electric is responsible for providing a reliable supply of power to its customers in all hours of the year. DTE Electric's system is connected to the broader grid and to ensure reliability the Company must plan for its future considering the broader energy market conditions across Michigan and the MISO region. Because the PCA sets the retirement schedule for the Company's remaining two coal-fired power plants, totaling approximately 4,100 MW of generation, and recognizing that the region is shifting from traditional dispatchable generation to significantly more intermittent resources, the Company expanded the scope of evaluating potential electric reliability impacts to ensure the PCA is reliable, resource adequate and diverse.[29]

The Company engaged with Astrapé Consulting and ITC to leverage a three-phased approach, as shown in Figure 5, that prioritized electric reliability while also seeking an affordable path to decarbonization. Astrapé performed resource adequacy modeling and ITC performed grid reliability modeling.

[29] Resource diversity, or diversity of generation supply as used in MCL 460.6t(8)(vi), is defined and quantified by Witness Mikulan as part of her risk assessment of the PCA and alternative portfolios.

Figure 5 - Three-Phased Electric Reliability Approach



By leveraging this comprehensive approach, which is discussed in more detail in the testimony of Witness Mikulan, DTE Electric is able to de-risk the PCA by ensuring customers have sufficient and diverse energy and capacity resources. Specifically, resource adequacy and grid reliability are supported by two essential components of the PCA: 1) the Belle River conversion provides a critical reliability resource as DTE Electric accelerates the retirement of the first 1,535 MW of coal at Monroe in 2028, and 2) the development of sufficient resources including renewables and storage in advance of the 2028 retirements ensures supply reliability for customers.

The plan also considers resource availability and extreme weather and expects resources to be located in the state of Michigan rather than relying on new or existing resources outside of the state, which may or may not exist, or be available to Michigan customers. As Witness Burgdorf explains in his testimony, the MISO Planning Resource Auction for Planning Year (PY) 2022/23 showed that even when the Effective Capacity Import Limit (ECIL) was sufficient to import capacity, there were not enough resources external to Zone 7 available.

Q53. Can you describe the differences between IRP, resource adequacy, and grid modeling?

A53. Yes. As shown in Figure 5, there are three types of reliability modeling that the Company leveraged to analyze and ensure electric reliability in this IRP. I will introduce each one.

1. **IRP Modeling**: IRP modeling is typically completed using capacity expansion models which run deterministic analysis to determine the lowest cost combination of resources available to meet a utility's forecasted peak demand (coincident with MISO's peak demand) plus the required PRM. The Company conducted this modeling using the EnCompass tool, a capacity expansion model. 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 provides additional detail on IRP modeling in her testimony.
2. **Resource Adequacy Modeling**: Resource adequacy modeling was conducted by Astrapé for MISO Local Resource Zone 7. Witness Burgdorf provides an overview of resource adequacy requirements. In addition, resource adequacy modeling was conducted to determine an ELCC assessment for the MISO

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LRZ7 to determine the reliability contribution of solar and battery storage resources. Witnesses Carden and Mikulan provide additional detail on resource adequacy modeling, in their respective testimonies.

3. **Grid Reliability Modeling**: ITC performed this modeling as described in Section IV of my testimony. 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 the identification of reliability issues and solutions. These efforts are further described by Witnesses Mikulan and Roy.

Q54. In addition to including a comprehensive modeling approach in this IRP, how has the IRP process changed since DTE Electric developed its 2019 IRP?

A54. With the addition of resource adequacy and grid stability reliability modeling, the modeling process the Company used in this IRP is more comprehensive than in the prior IRP and includes additional considerations and modeling tools. Witness Mikulan describes modeling enhancements more fully in her testimony including the expansion of modeling energy storage. In addition, the IRP process changed in the following ways since the 2019 IRP:

- IRP modeling software: In the 2019 IRP, Case No. U-20471, the MPSC Final Order included a recommendation for DTE Electric to host a two-day technical conference with interested stakeholders with the purpose of identifying and evaluating alternative modeling software for use in IRP. Following this recommendation, an effort was undertaken by the Company to evaluate several capacity expansion modeling programs including a stakeholder collaborative. Based on stakeholder feedback and four software trials performed by members of the IRP team, the Company chose EnCompass as its capacity expansion model for the 2022 IRP. See Part IV of my testimony, as well as Witness Manning's testimony for additional details.
- Forecasting: As discussed in detail by Witness Leuker in his testimony, the Company has taken steps to improve the load forecasting used for resource planning. Following the Commission order in Case No. U-20471, the Company has moved to a more recent time period for defining normal weather in response to potential impacts from climate change. Additionally, the Company has enhanced its forecasting processes through the implementation of automated metering infrastructure (AMI) data in forecast models. In response to anticipated changes in the energy industry with the increased adoption of behind-the-meter renewables and electric vehicles, the Company has implemented a more transparent and robust process to forecast these technologies.
- Modeling approaches: As discussed by Witnesses Manning in her testimony, the Company undertook a number of changes to enhance the modeling.

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- Coordination with transmission and distribution planning: This IRP supports greater integration of resource, distribution, and transmission planning processes. This integration is supported by the Company's efforts to develop advanced forecasting methods to support both distribution and IRP planning. In addition, there is coordination between the IRP, Transmission Optimization, Distribution, and Energy Supply teams on a peaker analysis as well as collaboration with ITC on transmission planning to inform the IRP process. These efforts are further discussed by Witnesses Leuker, Musonera, Roy and Morren in their testimonies.

- Environmental Justice (EJ) analysis: Through Executive Directive 2020-10, Governor Whitmer charged EGLE with developing the MI Healthy Climate Plan.[30] The MI Healthy Climate Plan focuses on environmental justice "to ensure Michigan's climate strategies uplift every portion of the state, including individuals and communities that have borne the brunt of climate impacts and are at the greatest risk of being left behind in the transition ahead."[31] Executive Directive 2020-10 also charged EGLE with considering environmental justice and health impacts in the Department's advisory opinion filed in the MPSC's IRP process. The Company conducted an EJ analysis to support EGLE's advisory opinion. Refer to Witness Marietta's testimony for additional detail.

Q55. How is environmental justice defined?

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[30] MI Healthy Climate Plan: https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588, accessed October 17, 2022.
[31] *Id*.

A55. DTE Electric refers to the State of Michigan's environmental justice definition, which defines EJ as the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income in the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn.[32]

Q56. You reference that an EJ analysis has been added to the 2022 IRP modeling process. What is the purpose of the EJ analysis?

A56. The purpose of the EJ analysis is two-fold. First, the EJ analysis in this IRP helps inform DTE Electric's modeling and planning process by identifying, qualitatively and quantitatively assessing the potential environmental and public health impacts of various alternative portfolios including impacts on vulnerable communities. Similar to other models leveraged in the IRP modeling process, like resource adequacy or rate impact analysis modeling, there are tools that are used for this analysis to bring additional visibility to potential impacts of various paths studied in this IRP. 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.

Q57. Can you describe the Company's EJ analysis?

A57. The EJ analysis evaluated the environmental and health impacts of certain portfolios. For each portfolio, the Company 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,

[32] *Id.*

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and expected changes in land use for new or retiring resources of identified vulnerable communities, and determined health impact estimates for air emissions. A narrative discussion of the quantitative and qualitative health and environmental impacts is described by Witness Marietta in his testimony.

Q58. How are vulnerable communities identified in the EJ analysis?

A58. The Company used the US Environmental Protection Agency (EPA) Environmental Justice Screening and Mapping Tool (EJSCREEN) Version 2.0 to conduct the EJ analysis. Vulnerable communities are identified as those having an EJ composite score at or above the 80th percentile for the State of Michigan, consistent with the US EPA approach[33].

Q59. Does DTE Electric have other considerations on how EJ is incorporated into long-term generation planning?

A59. This IRP is the first time that DTE Electric has formally integrated an environmental justice analysis into the IRP process, although in the 2019 IRP the Company did complete an assessment of CO_2 emissions as well as other emissions for specific portfolios. The Company recognizes that continuing to analyze EJ impacts of the generation transition will be an iterative process as the tools are refined and the Company engages communities and stakeholders and applies learnings to future IRPs. DTE Electric encourages stakeholder feedback to improve these analyses for future IRP processes.

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[33] 80th percentile US EPA, https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5, accessed October 19, 2022.

A core component of EJ is meaningful involvement of all people.[34] The Company recognizes that there are barriers that may prevent customers who wish to engage from participating in the IRP process. Such barriers could include but are not limited to: lack of awareness of the IRP process and its impacts; work, childcare, and other personal responsibilities; language accessibility; and transportation and/or technological accessibility. The Company made several efforts to address these barriers, including establishing an IRP section on its website, creating a public comment form on the website and an IRP email address, publicizing the public open houses through a variety of channels, hosting public open houses at different times of the day, recording and transcribing the public open houses for people unable to attend the live events, and translating the public open house transcriptions into five different languages. These efforts are described in further detail in Part IV of my testimony.

Furthermore, an IRP identifies if there is a need for additional demand- and supply-side resources over a long planning period. While impacts of plant retirements are location specific, new resource additions over the study period, such as wind, solar and storage are evaluated more generally at this stage in the planning process. The IRP does not site the locations of new resources, nor does the IRP design customer programs or workforce development and training programs to support implementation. The IRP also does not detail the environmental processes associated with retiring and decommissioning a power plant. Further opportunities

[34] State of Michigan, Department of Environment, Great Lakes, and Energy, https://www.michigan.gov/egle/public/learn/environmental-justice, accessed October 20, 2022.

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exist to partner and meaningfully engage with communities, stakeholders, and customers as part of the implementation of the approved PCA.

Q60. How do EJ considerations connect with the "Customer Focus and Community Accessibility" planning objective?

A60. The "Customer Accessibility and Community Focus" planning objective is described in Figure 2 as follows: "Provide flexible and accessible technology and grid options, and information that empowers and engages customers. Provide effective and timely communication with customers and stakeholders. Favor plans that support diversity of Michigan communities, suppliers and workforce." This planning objective connects with EJ considerations in the following ways:

- The PCA increases the adoption of renewables and storage resources and continues demand-side management programs, which support access to clean energy and energy management programs for customers. These resources are assumed to be developed in Michigan, which will drive investments in Michigan to support local businesses and grow clean energy jobs. While outside the scope of the IRP, the Company has numerous existing renewable resources, EWR and energy assistance programs that are designed to reach customers in specific geographic areas or at various income levels.
- As I detail in Section IV of my testimony, various means of outreach were used to reach customers, communities, and stakeholders as part of the IRP stakeholder engagement process including outreach to Belle River and Monroe Power Plant community representatives in advance of the IRP.

- The Company intends to provide a just transition for employees and communities, as demonstrated through the Retire with PRIDE initiative. As DTE Electric implements the PCA, we will continue to engage the Belle River and Monroe host communities as partners throughout the transition, retirement, and decommissioning processes, as well as to support efforts to foster economic development and investment within these communities and throughout Michigan. DTE Electric plans to maintain its no layoff commitment to employees, ensuring employees have the opportunity to continue to be a part of the Company. To deliver on this intention, the Company will work on several initiatives, including collaboration with union leadership and employees (both represented and non-represented), strategic workforce planning, workforce re-skilling, and employee redeployments.

The Company recognizes that the process of meaningfully engaging communities in the generation transition process will evolve over time as the PCA is implemented.

PART IV: STAKEHOLDER ENGAGEMENT AND COLLABORATION

Q61. How did the Company approach stakeholder engagement and collaboration?

A61. The Company engaged a broad range of stakeholders through a variety of methods during the IRP process to share information and educate them on the IRP process, listen to their concerns and objectives, encourage robust and informed dialogue on resource planning, and create opportunities to gather feedback to inform the Company's analysis and decision-making. Outreach efforts focused on four areas:

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1) public open houses, 2) public outreach, 3) technical stakeholder outreach, and 4) community outreach. The Company's goal was to be accessible while implementing a comprehensive, transparent, educational, and participatory stakeholder engagement process. These events provided stakeholders with various opportunities to provide input on how to meet Michigan's future energy and capacity needs, including reviewing and commenting on IRP inputs, scenarios, sensitivities, and technology options. The Company has also communicated key aspects of the IRP with employees, stakeholder organizations (e.g., MPSC, MISO, ITC), and community representatives. The DTE Electric Public Outreach Report (Exhibit A-1.4) details the Company's stakeholder outreach efforts.

Public Open Houses

Q62. How were the public open houses conducted?

A62. The Company hosted eight public open house events between January and April of 2022. The objectives of these events were to inform participants on the IRP process and key components of DTE Electric's generation transformation and provide an opportunity for the public to ask questions and offer feedback. The Company offered afternoon and evening sessions to accommodate varying potential participant schedules. DTE Electric did not hold in-person events with members of the public from January through April 2022 given the status of the COVID-19 pandemic, therefore, the public open house events were held virtually on Microsoft Teams Live. During each event, the Company provided an overview of key plan aspects followed by a question-and-answer segment. During the session, attendees had the opportunity to submit comments, questions, and/or general feedback through the chat function on the platform and the Company would either answer the question live or notify the attendees that the Company would be following up to further understand the question or consult with the proper subject matter expert if they did not attend the event.

During the first two public open house events, the Company requested feedback via a survey on future event topics to further tailor the content of open house events to the interest of the public. Subsequent open house agendas included topics such as renewables, emerging technology, customer demand-side and voluntary renewable programs, coal plant retirements, the Retire with PRIDE initiative, and grid modernization. More information on the public open houses is available in the Public Outreach Report, Exhibit A-1.4.

Q63. What additional steps did the Company take to be inclusive for individuals accessing and engaging in the virtual public open house meetings?

A63. In advance of the public open houses, my team consulted with DTE Energy's Abilities in Motion (AIM) Employee Resource Group to seek guidance on best practices and protocols for inclusive virtual meetings. The AIM Employee Resource Group is DTE Energy's affinity group for persons with a disability. Per AIM's guidance, the Company incorporated the following protocols for all public open house events:

- Recorded all meetings to post online
- Required all speakers to use headsets or microphones to ensure best sound quality

- Turned on transcription and made the transcripts available online
- Made it known to participants that closed captioning was available and provided guidance on how to enable that feature
- Posted the presentations on the dtecleanenergy.com website in advance of the public open house events, including an agenda that was reviewed at the beginning of each meeting

As stated previously in my testimony, the Company recognizes that there are barriers that may prevent customers who wish to engage from participating in the IRP process. While a variety of outreach methods were utilized during the IRP planning process, the Company acknowledges that this is an iterative process and there is an opportunity and need for ongoing outreach, engagement, and participation with communities, stakeholders, and customers throughout the generation transition and implementation of this plan.

Q64. How did the Company notify the public in advance of the public open house events?

A64. Multiple channels were used to publicize the public open house events, including: DTE Energy press releases; DTE Energy Empowering Michigan blog posts; DTE Energy social media posts on LinkedIn, Facebook and Twitter; direct outreach and email invitations to local officials, state elected officials, community-based organizations and other stakeholder organizations; and via the MPSC's MI Power Grid Phase III IRP workgroup listserv. Promotional materials and attendee lists for the public open houses are available in the Public Outreach Report, Exhibit A-1.4.

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Q65. Did the Company make the public open house information available for those who were unable to attend the live events?

A65. Yes. The Company recorded and transcribed each public open house event. Transcripts were also translated into five different languages: Arabic, Chinese, French, Hindi, and Spanish. Following each live event, the Company posted the event recordings and transcripts on dtecleanenergy.com (website) under the DTE CleanVision Integrated Resource Plan section. From January 1, 2022, through September 15, 2022, the public open house recordings had over 115 views and 670 resource documents were downloaded.

Public Outreach

Q66. In addition to the public open house events, did the Company make other efforts to conduct outreach with the public?

A66. Yes. The Company developed a section for the IRP on its website, created an online comment submission form with a direct link on the website, created an IRP email address (DTE_Electric_CleanVisionPlan@dteenergy.com) and conducted customer research to support public outreach and engagement. The Company established a comprehensive process to respond to questions and comments that were submitted through the IRP email and website comment link. Further information on the website, the process for responding to public comments, the questions and comments received, and the Company's responses are available in the Public Outreach Report, Exhibit A-1.4.

Q67. As part of public outreach, what customer research did the Company conduct, specific to the IRP?

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A67. DTE Electric engaged a third party, Purple Strategies (Purple), to conduct qualitative and quantitative "Voice of the Customer" (VOC) research to engage with its customers. Through Purple, the Company sought to better understand its customers' perspectives and their views and attitudes toward decarbonization, energy sources, and DTE Electric's plan for reaching net zero carbon emissions by 2050.

Q68. When was the VOC research conducted and what was the methodology?

A68. Purple conducted both qualitative and quantitative research from March through June 2022.

Phase one was the qualitative assessment, which was a blend of one on one, in-depth interviews (IDI) and online focus groups conducted between March 4, through April 7, 2022. Purple conducted IDIs with 17 community representatives, six industrial customers, and five commercial and small business customers. Community representatives include DTE-identified individuals working across state/local government, business and commerce, and other community-oriented organizations. Purple also conducted seven focus groups with a total of 26 residential customers that included a representative mix of demographic and geographic profiles. The Company did not participate in any IDIs or focus group discussions. Purple facilitated the IDIs and focus groups and anonymized the feedback and statements from participants.

Phase two, conducted from May 8, through June 8, 2022, was a comprehensive quantitative survey distributed both online and via telephone. Respondents included

1,293 residential customers with geographic weighting applied to proportionally represent DTE Electric's geographic footprint, 407 commercial and small business customers, and 128 community representatives. More information on the research methodology can be found in the Public Outreach Report, Exhibit A-1.4.

Q69. What are the key findings from the VOC research?

A69. According to the report provided by Purple, the VOC research identified several key findings:

- Overall, customers, from residential and commercial to community representatives, are familiar with the term "net zero" and support net zero goals.
- There is broad acceptance and desire for a diverse and balanced mix of energy sources, with renewable energy leading the way and natural gas playing a role to support reliability.
- Support for transitioning to cleaner energy will ultimately hinge on maintaining reliability and affordability. Customers generally assume that DTE Electric will continue to provide the reliable electricity they need. Affordability is on everyone's mind (especially given inflationary pressures, particularly the cost of energy), and customers often qualified their support by asking whether this long-term generation plan will result in higher rates.
- Customers – particularly residential – are generally unaware of the Company's plans to reach net zero, including recent actions like retiring coal plants. Most react positively to information about the Company's efforts to decarbonize and express a desire for additional communications and engagement from DTE Electric.

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- Ultimately, there is confidence that the Company will achieve its carbon reduction goals.

More information on the VOC research is available in the Public Outreach Report, Exhibit A-1.4.

Technical Stakeholder Outreach

Q70. How did the Company approach technical stakeholder outreach?

A70. The approach the Company developed was to establish a transparent decision-making process for resource planning and ensure technical stakeholders had an opportunity to provide input and stay informed regarding: (1) the modeling assumptions, scenarios, and sensitivities, (2) the progress of the Company's IRP process and (3) an overview of the Company's modeling results. The Company held six virtual workshops with technical stakeholders between January and August 2022. The Company engaged participants based on parties that participated in the Company's last electric rate case and the 2019 IRP proceeding or expressed interested in participating. The Company invited more than 40 organizations to participate in the technical workshops via an email invitation and several were also communicated via the MPSC's MI Power Grid Phase III IRP workgroup listserv. The technical workshops covered topics including modeling assumptions, scenarios and sensitivities, overviews of grid and resource reliability modeling, battery storage modeling and modeling results. In addition, the Company engaged with ITC on the transmission analyses. In between technical workshops, stakeholders were encouraged to email comments and questions to the Company at DTE_Electric_CleanVision@dteenergy.com.

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Q71. Were any additional technical workshops held?

A71. Yes. As stated earlier in my testimony, the Company selected the EnCompass software based in part by input from a two-day technical conference held in May 2020. A detailed report on this collaborative was submitted to the MPSC in June 2020 under Case No. U-20471[35]. For more information, see the testimony of Witness Manning.

Q72. Can you provide an overview of the technical workshops conducted between January and August 2022 in advance of the IRP filing?

A72. Yes, the Company held six virtual technical workshops. During the first technical workshop, the Company received input from technical stakeholders on topics and areas of interest. This feedback helped inform the agendas for the subsequent workshops. Each workshop was comprised of a presentation and question-and-answer segment led by various subject matter experts from across the Company, including the IRP team, as well as industry experts. The technical workshops included information about the IRP process and timeline, assumptions, scenarios and sensitivities analyzed to develop the Company's plan. This included a stakeholder scenario development session, a review of the IRP models, including resource adequacy and ITC's transmission modeling, discussion on interpreting results, and the sharing of modeling results across a range of scenarios and sensitivities. MISO also discussed managing reliability risk. The Company also held two special sessions on energy storage modeling with stakeholders and leading industry experts.

[35] DTE Electric Integrated Resource Plan Modeling Software Collaborative Summary Report, available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CIEbLAAX, accessed October 18, 2022.

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The workshop format allowed all participants to hear each other's questions and obtain answers from subject matter experts at the same time. This approach created consistency in sharing information, open dialogue, and the exchange of diverse ideas. Stakeholder comments and questions were addressed during the meetings with follow-up responses distributed to the inquiring attendees.

Common themes heard from participants at the technical meetings included questions around storage and resource adequacy modeling, input on the modeling assumptions for EWR (end-effects and T&D losses), renewable energy, load forecasting, and modeling assumptions. More information on the technical workshops is available in the Public Outreach Report, Exhibit A-1.4.

Q73. How did the Company collaborate with the local transmission owner, ITC?

A73. DTE Electric engaged ITC to study the impacts of three potential generation retirement cases on the transmission system. The Company asked ITC to perform a steady state, a stability, and a capacity import analysis, and provide the estimated costs of any associated transmission network upgrades to support the generation retirements and replacements under the different scenarios. The Company and ITC met virtually on a regular basis, between October 2021 and October 2022, to discuss the analyses, scope, and timelines. Witness Roy further describes this engagement in his testimony.

Q74. How did engagement with ITC on the transmission reliability study influence the Company's process and PCA?

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A74. As described in my testimony, electric reliability is the highest priority in DTE Electric's generation planning process and is the foundation of the PCA. The Company is responsible for providing reliable power for its customers, including customers currently participating in electric choice; collaboration with the local transmission owner ensures DTE Electric is accounting for the impacts of potential resource changes on power flow reliability.

ITC is a key industry partner in the three-phased iterative approach, as depicted in Figure 5, that the Company leveraged to ensure the plan is reliable and potential transmission impacts and associated costs are considered. The upfront engagement with ITC and the resulting transmission analyses helped inform and reaffirm the PCA. Refer to Witness Roy's testimony for the studies and the results of those studies that were performed to inform the IRP process and the studies performed on the PCA.

Community Outreach

Q75. Earlier in your testimony you referenced the Retire with PRIDE initiative. What is Retire with PRIDE?

A75. The sequential retirement of coal-fired power plants has been a key part of the Company's efforts to reduce carbon emissions. In 2020, the Company's senior leaders and the Energy Supply leaders overseeing power plant operations established a vision for retiring the Company's coal plants. The Company refers to this vision as Retire with PRIDE - which stands for People, Respect, Integrity, Dignity and Engagement.

DTE Electric recognizes that the retirement of coal plants impacts the employees who operate them every day, as well as the communities that host the facilities. The Company respects the legacy and contribution of these plants and wants to retire them with dignity and integrity. The Retire with PRIDE initiative is focused on engaging and partnering with employees, host communities, and other stakeholders to manage this process carefully. The Company's approach towards the employees and communities impacted by plant retirements and transitions presented in the PCA is further described by Witness Morren in his testimony.

Q76. How did the Retire with PRIDE initiative influence stakeholder engagement?

A76. In line with the Retire with PRIDE initiative, as well as the customer accessibility and community focus planning objective, the Company wanted to proactively engage coal plant host communities that will be impacted by the PCA. With this IRP having a 20-year study period with the potential to shift previously announced retirement dates, the Company conducted outreach with local elected officials and other community partners in the Belle River and Monroe communities in advance of the filing. The Company's objective was to engage community representatives to share information about the filing process, answer questions, hear feedback, and identify opportunities for collaboration. DTE Electric retained the services of a third-party economic development consultant, Camoin Associates, to support this community engagement and share the tools, techniques and processes used to successfully plan and prepare for future transitions. For more information, refer to the Public Outreach Report, Exhibit A-1.4.

Q77. How did DTE Electric engage the Belle River Power Plant community?

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A77. Knowing that the plan would evaluate both the full retirement and the conversion of Belle River, the Company's representatives engaged community representatives in July 2022. Because the potential transition of Belle River could occur within the first five years of the PCA, DTE Electric engaged economic development experts from Camion Associates to conduct a socioeconomic impact assessment on the retirement and conversion alternatives being studied. When the Company and the Belle River community representatives met in July, the socioeconomic study was discussed, and the community representatives were asked to provide input. The study and its results are further described by Witness Morren in his testimony.

Q78. How did DTE Electric engage the Monroe Power Plant community?

A78. The Company met with Monroe Power Plant community representatives in July 2022. While a PCA was not yet determined, DTE Electric was studying various retirement scenarios for a potential acceleration of Monroe's retirement. As such, DTE Electric wanted to engage Monroe community representatives to begin engagement in advance of an IRP filing. During the meeting, the Company's representatives shared information on the IRP process and communicated its desire to proactively discuss a future transition and potential impacts of that transition on the local economy and community. DTE Electric also asked for areas of concern, interest, and focus of the community, and how the community representatives wanted to stay engaged going forward. The Company and the community representatives who were present communicated a shared interest in partnering to scope and conduct a socioeconomic study to understand the current economic footprint of Monroe and the potential impact of any future transitions at a later date.

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Q79. What other efforts did the Company make to engage the community?

A79. DTE Electric sought feedback from community representatives across the Company's service territory as part of the Voice of the Customer research described previously in my testimony. Seventeen in-depth interviews were conducted, and 128 community representatives completed a quantitative survey. Community representatives include DTE-identified individuals working across state/local government, business and commerce, and other community-oriented organizations.

Q80. How did feedback from stakeholders impact the IRP process?

A80. DTE Electric appreciates the constructive dialogue and diverse feedback it has received across the various channels described in my testimony, as well as the time customers and stakeholders took to provide that feedback. The Company's outreach and engagement efforts with stakeholders supported the 2022 IRP process and PCA development in several ways. Because of the ongoing, comprehensive dialogue with stakeholders, this IRP process was robust and has led to a PCA that reflects feedback and input from stakeholders, including:

- A better understanding of the Company's customers' perspectives relative to the generation transition, including the expectation to continue to adopt clean technologies while staying reliable and affordable.
- The incorporation of feedback from technical stakeholders in the IRP process and analysis, including modeling tool selections, scenario and sensitivity development and suggestions (including a stakeholder scenario), and consideration of storage benefits.

- A PCA that incorporates input from technical analysis and collaboration with ITC, who provided insights and costs, on potential transmission impacts of generation alternatives.
- A commitment to partnering with communities and employees impacted by coal plant retirements and transitions. This includes the need to proactively partner with Belle River and Monroe power plant communities to understand the social and economic impacts of proposed transitions and/or retirements.

PART V: IRP MODELING RESULTS AND SELECTION OF PCA

Q81. What IRP modeling scenarios and sensitivities did the Company evaluate?

A81. As explained in detail in Witness Manning's testimony, the Company modeled over 100 different unique combinations of scenarios and sensitivities to support the IRP analysis. DTE Electric modeled eight scenarios in total, three of which are required by the MIRPP (Case No. U-18418). The three MIRPP required scenarios are Business as Usual (BAU), Emerging Technologies (ET), and Environmental Policy (EP), along with several sensitivities.

1. The BAU scenario evaluates the existing generation fleet that is largely unchanged apart from new units planned with firm certainty or under construction.
2. The ET scenario reflects potential advancements in technologies and economics of scale resulting in a 35% reduction in costs for DR, EWR, battery storage, and solar.

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3. The EP scenario analyzes carbon regulations targeting a 30% carbon emissions reduction from 2005 to 2030.

The Company also modeled the Carbon Reduction (CR) scenario based on the February 18, 2021, Order in Case No. U-20633 addressing Governor Whitmer's GHG emission goals.

The Company developed a Reference (REF) scenario using Company-developed assumptions as well as a High Electrification (HE) scenario that included electric vehicle adoption assumptions consistent with the MI Healthy Climate Plan. The Company also facilitated a collaborative technical workshop to develop a "Stakeholder Scenario" and twelve sensitivities. Finally, following enactment of the IRA, the Company developed a scenario (REFRESH) that reflected certain new and revised tax credits under the IRA as well as updated natural gas and wholesale electricity prices.

The Company also analyzed various sensitivities for certain scenarios, including sensitivities required by the Commission, those requested by staff and stakeholders, and some that DTE Electric utilized to show a robust range of possible future outcomes. Sensitivities included varying levels of load forecast, EWR, capital costs, market purchases, gas prices, retirement dates, and CO_2 emission adders to name a few. Refer to Witness Manning's testimony for detail on the scenarios and sensitivities.

Q82. What capacity requirement is the Company planning for?

A82. The Company is planning for capacity resources to meet its resource adequacy requirements (specifically the MISO planning reserve requirement (PRMR)) to reliably serve customer demand. As discussed by Witness Burgdorf in his testimony, the Company is required to demonstrate compliance with its PRMR. The forecasted peak load is a component used to determine the PRMR. The Company considered multiple load forecasts, including the starting point forecast, in its IRP modeling as described by the testimony of Witness Leuker. In his testimony, Witness Burgdorf also discussed efforts by MISO to develop a seasonal construct for capacity and potential implications for DTE Electric's planning.

In addition, beyond the MISO annual resource adequacy requirements, which are based on a summer peak one-year ahead, the Company plans for capacity resources to meet the planning reserve margin on a four-year forward basis, as required by 2016 PA 341, MCL 460.6w. These requirements are discussed by Witness Burgdorf in his testimony.

The capacity need and available resources to meet that need without (starting point) and with the PCA through 2042, are shown below in Figures 6 and 7. Refer to Witness Manning's testimony and Exhibits A-3.3 and A-3.4 for additional details.

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Figure 6 - Starting Point Projected Capacity (MW)

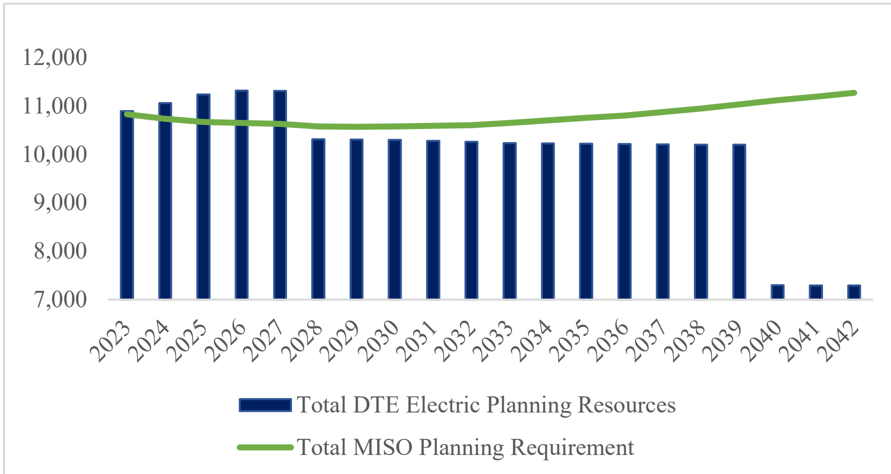
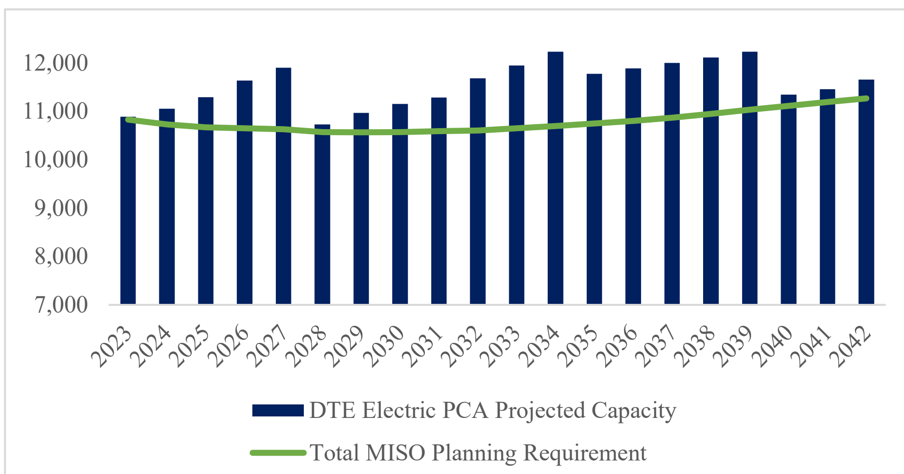


Figure 7 - PCA Projected Capacity (MW)



Q83. Based on the results of the Company's IRP process, will the Company require additional capacity to serve the electric demand of its customers in the next five years?

A83. No. In the first five years of the PCA, the Company will have sufficient capacity to meet its PRMR as shown in Figure 6.

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Q84. MCL 460.6t(6), as interpreted by the Commission in its February 20, 2020, order in Case No. U-20471, at page 28, requires a request for proposal to be issued prior to the IRP filing in certain instances, namely if the utility plans to buy or build new supply-side generation resources within the three-year planning period covered by the IRP. How is this issue addressed in the IRP?

A84. While the Company does not have a need for new supply-side generation capacity resources within the three-year planning period covered by the IRP to meet its PRMR, the Company does plan to buy or build new supply-side resources to meet customer demand for its VGP Program. The Company conducted an RFP for renewable generation in 2022, has included the RFP results in this filing as described by Witness Hernandez's testimony and has incorporated the RFP results into its modeling as a sensitivity as discussed by Witness Manning in her testimony.

Q85. How was the IRP process integrated with DTE Electric distribution planning?

A85. This IRP increased the coordination between distribution planning and generation planning. As discussed by Witness Musonera in her testimony, the Company submitted its second distribution grid plan (DGP) to the Commission in September 2021. The DGP plan lays out a vision and the investments necessary to enhance reliability amid more extreme weather conditions and higher integration levels of electric vehicles (EVs) and other distributed energy resources such as solar and battery storage. The Company has several ongoing efforts that support improved long-term, integrated resource planning, and providing cleaner resources reliably and affordably to DTE Electric customers. These efforts include load forecasting improvements, distribution costs assumptions, and an analysis of certain peakers within the Company's peaker generation fleet. These efforts are discussed in more detail by Witnesses Leuker, Morren, and Musonera in their testimonies.

Q86. What is the role of emerging technology in this IRP and DTE Electric's net zero goal?

A86. Renewables and battery storage will play key roles in DTE Electric's transition towards cleaner energy, along with natural gas, like the Belle River Power Plant conversion. While the first half of the PCA's 20-year study period relies on known, commercially available technologies, additional technology solutions are needed to support a net zero generation mix that is diverse, reliable, and affordable. Emerging technologies such as SMR, hydrogen, CCS, and forms of mid- to long-duration energy storage will play an important role in the industry as DTE Electric works toward a net zero goal while maintaining reliability and affordability. While a likely need for a low or zero carbon dispatchable resource has been identified in this PCA to replace the second two units of Monroe Power Plant in 2035, commercially available, low or zero carbon dispatchable technologies are still limited and expensive. DTE Electric recognizes that costs and commercially available technologies will change over the course of the study period. Public policies such as the IRA, research and development funding, and technological advancements are expected to spur the evolution of these emerging technologies and their pace of development in supporting commercialized resources such as wind, solar, and lithium-ion batteries. The Company supports the advancement of emerging technologies as DTE Electric evaluates how to meet the future needs of our customers and replace the second two units of the Monroe Power Plant.

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As discussed further by Witness Mikulan in her testimony, the Company will remain flexible and evaluate technologies to meet the need in 2035, including CCGTs with CCS, SMRs and mid- to long-duration storage in future IRPs.

Q87. How did the Company evaluate the modeling results and select the PCA?

A87. The modeling results identified a wide range of least-cost portfolios that varied based on the assumptions used in the various scenario and sensitivity combinations. Witnesses Manning's and Mikulan's testimonies outline in detail the IRP modeling outputs and features of the portfolios, comparing alternatives in terms of cost (net present value revenue requirement (NPVRR)), reliability, and emissions.

In following the modeling process, as depicted in Figure 4 of my testimony, the Company identified a Preliminary PCA and began to assess the results (Steps 6-7). As Witness Mikulan describes in her testimony, while the assessment was underway, Congress and the Biden Administration passed the IRA. The Company then developed a new scenario to evaluate the potential impacts of the initial IRA on the Preliminary PCA and as well as a few other modeling portfolios. The PCA was subsequently updated, resulting in the Final PCA, or what I refer to as the PCA throughout testimony. The PCA now includes additional wind starting in 2028 and additional storage, wind, and solar as compared to the Preliminary PCA.

Both the Preliminary and the Final PCA were included in the IRP synthesis and risk analysis processes. The proposed PCA scored high in the risk analyses, meaning it is less risky than most alternatives. Based on the synthesis of results of all the analyses, the Final PCA is the most reasonable and prudent option to meet energy

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and capacity needs while doing so affordability and expediting the Company's carbon reduction efforts.

Q88. How does the PCA align with the statutory criteria and DTE Electric's planning objectives?

A88. The IRP complies with the IRP filing requirements in MCL 460.6t(5) and Commission orders. The PCA also aligns with the statutory criteria for approval of an IRP and DTE Electric's planning objectives as summarized in Exhibit A-1.5, DTE Electric Alignment of Planning Objectives and IRP Criteria.

PART VI: ESSENTIAL ELEMENTS SUPPORTING THE PCA

Q89. Are there supporting elements essential to the success of the IRP?

A89. Yes. These include the following:

- Cost pre-approval for approximately $135 million to support the conversion of Belle River Power Plant and $8.7 million for demand response, as supported by Witnesses Morren and Farrell.
- Regulatory asset treatment for the NBV and decommissioning costs associated with Monroe Power Plant and the retiring coal handling assets at the Belle River Power Plant; the regulatory asset would also include ongoing investments needed at Monroe to operate safely and reliably through retirement subject to prudence review in future proceedings. This request is further supported by Witnesses Lepczyk and Uzenski.

- An update to the current financial compensation mechanism to support the generation transition as authorized under MCL 460.6t(15), as supported by Witnesses Lepczyk and Hernandez.

Q90. Can you explain the statutory and regulatory criteria addressing pre-approval of costs in the IRP?

A90. Yes, MCL 460.6t(11) provides that, in approving an IRP, the Commission shall specify the approved costs for future recovery as follows:

> 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 facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase 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.

The Commission's IRP filing requirements specify the information necessary to support pre-approval requests based on asset categories (e.g., demand-side resources, renewable energy, supply-side generation less than 225 MW).

Q91. What costs are proposed for pre-approval in this IRP?

A91. DTE Electric proposes pre-approval of capital costs related to the Belle River conversion and the Company's demand response programs that will commence within three years of the Commission's approval of the Company's IRP and PCA. More specifically, DTE Electric requests pre-approval of the following:

- $135 million in projected capital costs to convert Belle River to operate on natural gas instead of coal by the end of 2026
- $8.7 million in projected capital costs related to the sustainment and growth of the Company's demand response programs

Company Witnesses Morren and Farrell support these respective pre-approval requests in their testimony, including breakdown of these amounts, timing, and compliance with statutory criteria and Commission's filing requirements based on the applicable project type.

Q92. You discuss the benefits of PCA in terms of reliability, affordability and decarbonization. Can you discuss further how the proposed Belle River conversion supports a reliable, affordable path to decarbonization and accelerated coal retirements?

A92. Yes. I will summarize each in turn:

- Reliability:
  - The conversion provides DTE Electric's customers with a reliable, dispatchable resource as large amounts of intermittent resources replace dispatchable coal resources. As a peaking resource, Belle River will most often operate during times when customer demand is higher (peak) or when other supply resources may be unavailable.

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- Conversion of the Belle River Power Plant won't just impact the Company's customers; MPPA's customer base will be impacted as well. They will continue to receive the benefits of a cost-effective resource that provides reliability and capacity – as well as reduced emissions – once converted.

- Affordability:
  - As Witness Mikulan describes, when pairing a staggered two-unit retirement of Monroe in 2028 and 2035 with the conversion of Belle River, the PCA saves customers nearly \$100 million in NPVRR over the alternative which does not include a conversion.
  - In terms of overall capital costs, a Belle River conversion is approximately \$130 per kilowatt (kW), a fraction of the cost of a new natural gas combustion turbine (\$800/kW) or a new CCGT (\$1,110/kW).
  - Additionally, the Belle River conversion is an efficient use of existing infrastructure. As Witness Roy describes, transmission system reliability studies conducted by ITC indicate that converting the Belle River Power Plant provides near-term savings of \$350 million in transmission system impacts.
- Decarbonization:
  - It also will significantly reduce CO_2 emissions from current Belle River operations, achieving an approximate 90-95% carbon emissions reduction from current annual levels. Furthermore, cumulative CO_2 emissions reductions are 40% lower with the plant

operating on natural gas through 2039 than operating Belle River on coal through 2030 as proposed in the 2019 PCA.

- In addition, by enabling two units at Monroe to retire nearly 12 years earlier than originally planned, the Belle River conversion will further facilitate additional fleet-wide carbon emissions reductions, allowing DTE Electric to achieve a 65% carbon reduction goal in 2028
- The converted Belle River peaking resource will help to bridge the period of time from when natural gas must play a role in supporting a reliable retirement of coal to when low or zero carbon dispatchable emerging technologies are both commercially available on a utility scale and more affordable. The Belle River peaking resource is expected to retire by 2040.

Q93. Is the Company proposing a new financial compensation mechanism related to PPA agreements pursuant to MCL 460.6t(15)?

A93. Yes. This IRP expands the scope of DTE Electric's renewable build projected to reach 60% of our energy mix in 2042. The FCM proposed by the Company will support the generation transition by providing an incentive on new or modified PPAs as authorized by MCL 460.6t(15). In his testimony, Witness Lepczyk addresses the need and methodology for an FCM for new and modified purchased power agreements based on the Company's after-tax weighted average cost of capital (WACC) using its total capital structure. This methodology is consistent with the statutory provisions applicable to the FCM and is an important component of the PCA's implementation. The Company proposes that this FCM would replace

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and augment the shared-savings FCM approved by the Commission in Case No. U-20713 that is limited to renewable energy contracts under the Company's voluntary green pricing program. Specifically, the Company is proposing the new WACC based FCM methodology on all new and modified purchased power contracts.

Q94. Why is the Company including the FCM request as part of the PCA?

A94. The PCA proposes a significant level of new generation to be developed over this IRP study period. As detailed by Witness Lepczyk, the FCM will allow the Company to manage negative impacts associated with PPAs while still entering cost-competitive agreements for projects that third parties may propose to implement the PCA. An FCM is in place for other utilities in Michigan and is essential to compensate the utility for some of the financial risks associated with purchased power agreements.

Q95. In Part I, you introduced the proposal for regulatory asset treatment for the Monroe Power Plant and the Belle River Power Plant coal handling assets. Why is DTE Electric utilizing the IRP filing to address this regulatory request?

A95. This IRP involves major decisions about the future of DTE's Electric power generation fleet, the communities it serves, and its workforce. DTE Electric's PCA proposes to accelerate the retirement of coal generation and replaces that generation with the Belle River conversion and investments in new resources, such as solar, wind, and battery storage. To implement the PCA and make other investments to operate a safe and reliable electric system, the Company needs to be financially sound, including maintaining a healthy balance sheet. Implementation of the PCA is not feasible without certainty regarding the financial treatment of investments in

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the Company's coal fleet. The coal fleet has served the Company's customers reliably over many decades and denying recovery of these investments while they are transitioned to retirement would be a departure from prior Commission policy relative to utility plant retirement. As discussed by Witness Lepczyk in his testimony, the NBV at stake is material to the Company's financial integrity and ability to effectively implement the PCA.

Moreover, all parties involved, including employees, communities, and the Company, need certainty now to proactively plan for the transition over the next several years, reinforcing the need to address the long-term generation and financial planning issues holistically in this IRP. Thus, the decisions related to the regulatory treatment of the NBV, and decommissioning costs associated with the retiring coal assets, cannot be separated from decisions on the appropriate retirement dates in this IRP.

Q96. Has the Commission addressed the issue of NBV related to retiring coal plants in the context of IRPs?

A96. Yes, the Commission has recognized the importance of this issue of net book value in long-term planning and expressed interest in understanding the customer impacts of different financing alternatives. In DTE Electric's 2017 Certificate of Necessity filing (Case No. U-18419), the Commission expressed an interest in understanding the rate impacts from recovering book value associated with the coal plant retirements through securitization or other financial measures, rather than traditional depreciation schedules.[36] Witness Lepczyk discusses different methods

[36] MPSC Case No. U-18419, April 27, 2018 order, page 120.

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and supports his analysis that the proposed regulatory asset does not materially impact cost to customers. The regulatory asset places the amounts in a different rate category and mimics current depreciation rates.

These issues were also recently addressed by the Commission in Consumers Energy's 2021 IRP with approval of a regulatory asset as part of the settlement agreement in conjunction with accelerated generation plant retirement dates.

Q97. Did the Company assess alternative financial approaches to the regulatory asset approach for the net book value of the coal assets proposed in this PCA?

A97. Yes. As Witness Lepczyk describes in his testimony in further detail, the Company evaluated three options for addressing the net book value and associated decommissioning costs for Monroe and the retiring coal handling assets and associated decommissioning at Belle River. The options assessed were 1) a regulatory asset mechanism, 2) securitization, and 3) accelerated depreciation that would align depreciation rates to the retirement dates proposed in this PCA. Based on this analysis, its findings, and the Company's interest in finding a path to accelerate decarbonization goals, DTE Electric is proposing the regulatory asset treatment approach in this PCA.

Q98. Can you describe the regulatory asset mechanism that is proposed in the PCA?

A98. Yes. The Company proposes that a regulatory asset mechanism be established to facilitate the recovery of the net book value, decommissioning costs and ongoing maintenance capital (2025-2035) for Monroe Power Plant, estimated at $3.1 billion, $300 million and $700 million, respectively, and the retiring coal handling assets and associated decommissioning costs at Belle River Power Plant, estimated at $209 million and $30 million respectively. Approval of the regulatory asset is necessary to support implementation of the PCA in the first five years and to proceed with the phased accelerated retirements at Monroe. Witnesses Lepczyk and Uzenski describe these proposals in detail, in their testimonies.

Q99. The PCA retires Monroe Units 3 and 4 in 2028 and Units 1 and 2 in 2035. Why is approval of a regulatory asset treatment for the net book value, the ongoing investments, and decommissioning costs associated with Monroe critical to address in this IRP?

A99. Regulatory asset treatment for Monroe Power Plant is essential to the Company's decision to accelerate the retirement of the facility. Proactive planning is needed to manage a thoughtful transition of more than just the electric system; that same long-term planning should be extended to support the transition of employees, the community, the environment, and the operational management of Monroe. The approval of a regulatory asset as proposed in the PCA provides the certainty required to initiate the long-term planning required to begin the transition of the electric system, and the network of systems connected to Monroe Power Plant. Appropriate recovery of the remaining net book value and decommissioning costs is a prerequisite to the Company's ability to implement the PCA and retire Monroe early.

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Q100. How does the Company seek to address the net book value and decommissioning costs associated with Belle River Power Plant's coal handling system in this IRP, and why is this issue critical to address in this PCA?

A100. The net book value of the coal handling assets at Belle River at the time of fuel conversion from coal to natural gas is much lower than the amounts associated with Monroe due to the existing depreciation schedule for Belle River, the smaller plant size, and the fact that only certain systems are being decommissioned as part of the Belle River conversion. Notwithstanding the difference in amount, the Company is proposing a consistent approach for addressing these unrecovered amounts. Addressing this issue in the IRP now will provide certainty on customer rates and financial and resource planning to facilitate the transition at Belle River leading up the conversion in 2025 and 2026 and support the plant's orderly transition. As discussed by Witness Morren in his testimony, a decision in this IRP on the conversion is needed to allow adequate time for engineering design and construction to proceed under the proposed timeline. It is important to recognize the interconnected nature of the PCA elements, with resolution of the NBV amounts supporting the Belle River conversion, which in turn supports acceleration of the Monroe retirement dates and additional investments in renewable energy and storage.

PART VII: IMPLEMENTATION OF THE PCA

Q101. How will the Company implement the PCA's investments within three years of the Commission's approval of the IRP?

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A101. The Company has developed an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the PCA focusing on the first three years following approval of this IRP. The implementation plan will vary depending on the specific resource. Overall, the Company is effectively positioned to implement the near-term investments and will secure the necessary workforce, resources, materials, and contracts.

In his testimony, Witness Morren discusses the implementation plan for the Belle River conversion project, including scope, procurement, schedule, and cost. Witness Morren also addresses the implementation strategy for energy storage, with the Company first gaining experience with the Slocum battery project if approved in the Company's pending rate case and preparing for the additional 46 MW of battery storage in 2025 under the PCA (i.e., 60 MW total by 2025). In her testimony Witness Hernandez addresses the use of competitive procurement and other considerations related to the development of new renewable energy and energy storage resources. The detailed implementation for CVR/VVO will be included in future distribution grid plans and regulatory cases as discussed by Witness Musonera in her testimony. The Company has extensive experience implementing EWR and DR programs, and funding and program design details will be addressed through other regulatory proceedings. Typical implementation plans are contained in my Exhibit A-1.3 DTE Electric PCA Implementation Plan.

Q102. How will the Company report on the status of an approved PCA pursuant to MCL 460.6t(14)?

A102. MCL 460.6t(14) provides that "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 under subsection." The Company plans to file with the Commission annual status reports on the implementation of the PCA elements, including those for which cost pre-approval is sought. The Company proposes filing in this docket the first annual report one year from the date of a Commission order approving the IRP with subsequent reports filed annually thereafter. Additional detailed reporting on demand response programs, including events called, customer participation, and spending, will also be provided in demand response proceedings as directed by the Commission.

Q103. Can you discuss the role of competitive bidding in the implementation of the PCA?

A103. Competitive bidding will play an important role in implementing the PCA. The Company plans to use established competitive bidding processes to arrange for equipment and services to construct the Belle River conversion project, to design and engineer CVR/VVO, and to administer and evaluate certain demand-side programs. In addition, the Company plans to use competitive bidding to arrange for new resources, including solar, wind, and energy storage as set forth in the PCA. Given the dynamic nature of the industry as discussed in Part III of my testimony, use of the request for proposal processes will ensure customers benefit from up-to-date market conditions that could affect the amounts, deployment timing, and pricing of these resources. The Company would bring forward specific projects or contracts to the Commission for approval.

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Q104. The Commission recently adopted new competitive guidelines for new resources in Case No. U-20852. Can you discuss how the Company will use these guidelines in its competitive bidding to implement the PCA?

A104. The Company has not yet had an opportunity to apply the new competitive bidding guidelines. Currently planned and approved projects were procured pursuant to the settlement agreement in Case No. U-20713,[37] that included specific competitive bidding requirements for RFPs for VGP assets through 2025. The VGP settlement RFP structure incorporates many features the Commission included in its new competitive bidding guidelines including increased transparency, open non-discriminatory treatment of resources without a minimum size, the use of an independent evaluator to oversee portions of the process, and separation of responsibilities by DTE Energy employees.

As the Company begins to add non-VGP resources, including energy storage and renewables, the Company will consider the Commission's guidelines in designing future RFPs, with the goal of ensuring that our customers benefit from competitive pricing (obtained through open, transparent, and non-discriminatory RFPs) and a diverse generation mix. RFPs assist the Company in reaching these goals, which align with IRP criteria, because the process ensures the Company obtains the best available pricing for the best available projects and opens the field for creative options and newer technologies that the Company may not yet have significant experience with. Refer to Witness Hernandez for additional information on

[37] See Case No. U-20713, June 9, 2021, Order, Exhibit A, p 13 §11; Projects associated with customer-requested projects utilize a specialized competitive bidding process, set out in §9.1.2.

competitive bidding processes for new resources and alignment with IRP criteria and competitive bidding guidelines.

Q105. How does the PCA mitigate implementation risks?

A105. Relative to implementation of the PCA, there are risks that pertain to execution of the plan. I discussed several risks affecting the electric utility industry in Part III of my testimony, including changes in the industry. Witnesses Mikulan and Hernandez discuss several risks including economic, weather, fuel prices, supply chain, siting and interconnection delays.

The PCA accounts for implementation risk in the following ways:

- Times the development of new resources in advance of large-scale retirement of two units at Monroe Power Plant in 2028
- Diversifies renewable energy resources by adding solar in the near term to build on the Company's prior investments in wind and potentially mitigating siting issues associated with wind development
- Includes the Belle River conversion as a peaking resource that provides dispatchable capacity as DTE Electric and other electric utilities in MISO retire coal and integrate thousands of megawatts of new renewables
- Leverages existing infrastructure through the Belle River conversion, avoiding interconnection delays, siting challenges, and near-term transmission system costs for nearly 1,300 MW of capacity
- Relies on commercially available technologies for the first ten years of the PCA

- Remains flexible to consider the role of low and zero carbon emerging technologies in the second half of the PCA once technologies have had time to further develop and commercialize
- Leverages the Company's considerable experience, established network of contractors, and channels of outreach and delivery to design and implement EWR and DR programs
- Leverages the Company's requisite project management and procurement experience to implement the PCA, including the building and acquisition of renewable energy and energy storage and the construction at Belle River to support the fuel conversion. DTE Electric is gaining experience with battery storage and CVR/VVO and looks to build on that experience as battery storage and CVR/VVO are scaled up as part of the PCA.

Q106. 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)?

A106. Yes. Consistent with our past practices and our commitment to support Michigan-based suppliers, the Company will strive to utilize Michigan workers as we implement the PCA. In our request for proposals and during contracting, the Company has traditionally indicated a preference for suppliers and projects that have Michigan headquarters and that utilize Michigan workers and will continue to do so. DTE Energy has a strong track record of supporting Michigan businesses and workers, spending nearly $16 billion and creating and sustaining 54,000

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Michigan jobs since 2010 as of December 31, 2021[38]. As noted in Part I of my testimony, the PCA drives about $9 billion of investment in clean energy over the next ten years, creating or retaining over 25,000 Michigan jobs, and supporting the State's economy while reducing carbon emissions and maintaining reliable power.

PART VIII: CONCLUSION AND REQUEST FOR APPOVAL

Q107. Can you summarize the Company's requests for Commission action in this proceeding?

A107. Yes, the Company is seeking the following Commission action:

1. 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;
2. Pre-approval of capital costs associated with specific investments ($135 million Belle River conversion and $8.7 million in demand response) that commence within three years of the Commission's approval of the Company's IRP and PCA;
3. Approval of the Company's proposed FCM based on the Company's after tax WACC under MCL 460.6t(15) applicable to all new and modified PPAs;
4. Determination that the Company does not have a capacity need in the next five years pursuant to PURPA;

[38] DTE Energy Michigan spend and jobs, https://skrift.meltwater.io/site/5e12ac481b7bea03e16a9079/article/61f14d3b3aca84001973eb1e, accessed October 19, 2022https://www.globenewswire.com/en/news-release/2022/01/26/2373513/0/en/DTE-Energy-invests-2-2-billion-with-Michigan-businesses-in-2021.html

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5. Determination that the Company complied with the RFP requirement to the extent it is applicable;
6. A determination that the Company complied with the statutory requirements, modeling parameters, filing requirements, and other orders and guidance applicable to IRPs; and
7. Approval of regulatory asset treatment for net book value, decommissioning costs, and ongoing investments of the Monroe Power Plant and the net book value of retiring coal handling assets and decommissioning costs at the Belle River Power Plant.

Q108. Why should the PCA be approved?

A108. The PCA is the most reasonable and prudent means of meeting DTE Electric's energy and capacity needs based on the criteria set forth in MCL 460.6t and complies with the Commission's filing requirements and other applicable orders.

Q109. Does this complete your direct testimony?

A109. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

LAURA K. MIKULAN

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF LAURA K MIKULAN

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

A1. My name is Laura K. Mikulan (she/her). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company) within Business Planning and Development as Manager – IRP.

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 with a Bachelor of Science in Chemical Engineering in 1995.

Q4. Have you completed any other courses of study?

A4. I have taken Power Systems Engineering, Best Practices in Electric Utility Integrated Resource Planning, EnCompass Capacity Expansion model training by Anchor Power, internal training on Revenue Requirement modeling, other seminars, and Company-sponsored courses.

Q5. What work experience do you have?

A5. In 1995, I hired into Detroit Edison, later DTE Electric, as an Engineer in the Professional Opportunity Program. There I had four diverse 6-month assignments in the water chemistry laboratory, the Environmental department, Monroe Power Plant maintenance group, and the Fermi 2 chemistry group.

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From 1997 to 2004, I worked in DTE Electric's Fossil Generation department as the plant chemical engineer in several power plants, including Monroe and Trenton Channel. In this role, I was responsible for the plant chemistry programs, which included water chemistry and lubrication. In addition, I was involved in the design and startup of the Monroe Selective Catalytic Reduction equipment to reduce nitrogen oxides (NO_X), and the associated chemical feedstock sourcing studies.

In 2004, I transferred to the long-term modeling group, a part of the Generation Optimization department, as a principal market engineer. In that role, I performed numerous analyses using dispatch and planning models, including PROMOD® and Strategist®. In 2007, the long-term modeling group transitioned from the Generation Optimization department to the Business Planning and Development department and changed names to IRP and Modeling.

In 2009, I was promoted to supervisor professional, IRP. My responsibilities included integrated resource planning, dispatch modeling, economic analysis and long-term environmental strategy. I was DTE Energy's liaison to Michigan's Stakeholder Technical Advisory Team on modeling compliance scenarios for the Clean Power Plan (CPP). I also provided support to the Electric Power Research Institute (EPRI)-Michigan CPP Analysis Project that was completed by EPRI in 2016. In 2017, I was the DTE lead on Michigan Public Service Commission (MPSC) IRP 6t collaborative for two working groups, "Forecasting, Fuel Prices and Reliability" and "Other Market Options and Advanced Technologies."

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In 2017, I was promoted to manager – Integrated Resource Planning, a part of the DTE Electric's Business Planning and Development Department. I am now responsible for the analytical support, overall IRP modeling process, and development of DTE Electric's Integrated Resource Plan. I lead a team of modelers and analysts that run the IRP models and perform the analysis to support the Integrated Resource Plan.

In 2021, I participated in the MI Healthy Climate Plan Collaborative in the Energy Production, Transmission, Distribution and Storage Workgroup. I also served as a co-facilitator for the Electric IRP Guidelines Subgroup in this workgroup. In 2021 I participated in the Advanced Planning Collaborative for the MI Power Grid Phase II initiative and in 2021-2022 I participated in the MI Power Grid Phase III initiative: Integrated Resource Plan (Michigan IRP Parameters (MIRPP), Filing Requirement, Demand Response Study, Energy Waste Reduction Study).

Q6. Have you been involved in prior proceedings before the Michigan Public Service Commission (Commission or MPSC)?

A6. Yes. I was a witness in the following cases:

U-18091 DTE Electric PURPA Avoided Cost Case
U-20471 DTE Electric Integrated Resource Plan

In addition, I supported testimony and discovery in the following cases:

U-17767 DTE Electric 2014 General Rate Case
U-18014 DTE Electric 2016 General Rate Case
U-18255 DTE Electric 2017 General Rate Case

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1	U-18419	DTE Electric 2017 Certificate of Necessity
2	U-20162	DTE Electric 2018 General Rate Case
3	U-20561	DTE Electric 2019 General Rate Case
4	U-20836	DTE Electric 2021 General Rate Case

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<u>Purpose of Testimony</u>

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to describe and support the Integrated Resource Plan (IRP) that is being submitted by the Company as required under section 6t of 2016 PA 341 (PA 341). My testimony is organized into the following sections:

I. Describe several steps of the planning and modeling process, the modeling and studies performed, and the integration of the analysis and models in support of the IRP;

II. Describe emerging generation technologies and the process used to select which technologies to include as alternatives in the IRP model;

III. Describe how the Resource Adequacy study was used in the IRP modeling and how the Effective Load Carrying Capability (ELCC) assumptions for solar and storage were developed;

IV. Describe the benefits attributed to battery storage resources and how the assumptions were developed;

V. Describe the build plans used in the Transmission Analysis performed by the local transmission owner, ITC Transmission (ITC), how the ITC Scenarios were designed, and how the results of the ITC Transmission Analysis (Grid Reliability Modeling) were used in the IRP modeling;

VI. Describe the carbon dioxide (CO_2) accounting that was performed;

VII. Describe and support the risk analysis that was completed, which includes a stochastic financial risk assessment and an evaluation of key inputs which have changed since modeling commenced; and

VIII. Describe DTE Electric's 2022 IRP proposed course of action (PCA) and the process for synthesizing the modeling results into the PCA.

Q8. Are you sponsoring any Exhibits?

A8. Yes, I am sponsoring the following Exhibit:

Exhibit	Description
A-2.1	ITC Scenario descriptions

Q9. Was this Exhibit prepared by you or under your direction?

A9. Yes, it was.

SECTION I: THE PLANNING AND MODELING PROCESS SUPPORTING THE IRP

Q10. When did DTE Electric last engage in an IRP process?

A10. As discussed by Witness Leslie in her testimony, DTE Electric last filed an IRP on March 29, 2019, in MPSC Case No. U-20471 and received the final order on April 15, 2020.

Q11. What are some of the modeling differences in this IRP from the last IRP filed in 2019?

A11. Modeling differences included in this IRP are as follows:

1. Utilization of new capacity expansion modeling software as discussed in more detail by Witnesses Leslie and Manning in their testimonies;
2. An increased focus on reliability and inclusion of a Resource Adequacy study to look at the ability of available power resources to reliably serve electricity demand based on the proposed PCA;
3. Incorporation of tiered ELCC assumptions into the capacity expansion optimization model for solar and storage resources as discussed in Section III;

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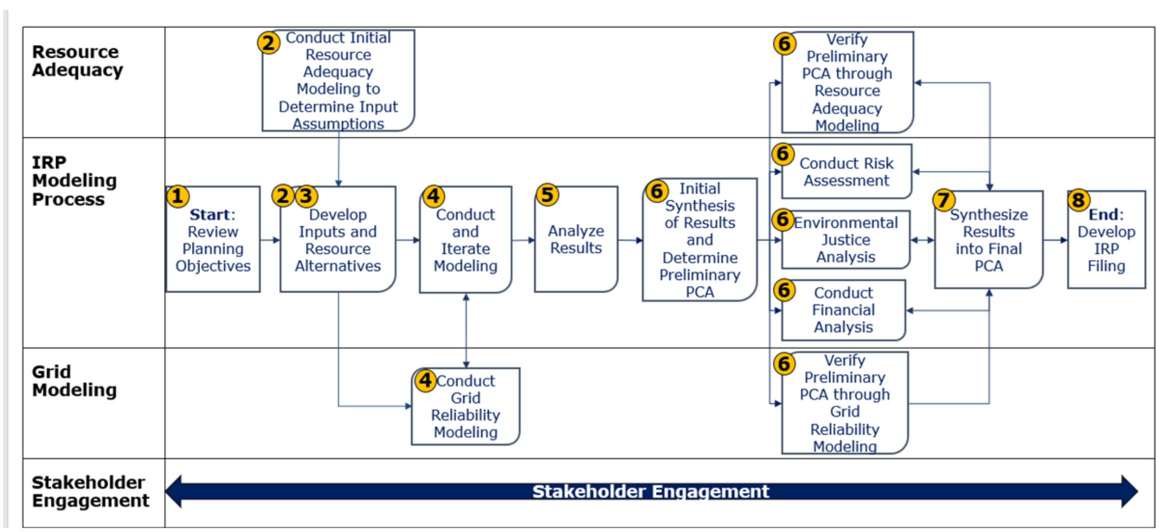
4. Incorporation of the Grid Reliability modeling from ITC in the development and optimization of the PCA; and
5. Enhancement of the modeling of energy storage system or battery benefits.

Witness Manning also provides additional modeling enhancements from the last IRP.

Q12. What are the planning and modeling steps associated with conducting an IRP process?

A12. Witness Leslie discusses, in her testimony, the Company's high-level approach to the IRP process. I will discuss the specific planning and modeling steps of that process. These steps are shown in Figure 1 below.

Figure 1. IRP Process overview



To conduct an IRP process, the Company must perform planning and modeling to determine if currently available resources meet future customer needs. These analyses can include both resource additions and existing resource retirements. If a capacity shortfall is forecasted, potential resource options should be analyzed, with a range of input assumptions, in order to formulate cost-effective resource portfolios. The IRP team performs this analysis using a software program that determines the least-cost portfolio chosen from different resource retirement options and many resource alternatives that can replace the energy and capacity associated with a retirement. This is called capacity expansion, or IRP optimization.

Ultimately, the Company develops a PCA that meets reliability requirements at a reasonable cost compared to other alternatives, and that supports the Company's planning objectives and meets the statutory requirements of the state. There are numerous steps involved in developing a comprehensive resource plan, which include:

1) Review planning objectives
2) Develop inputs
    a. Determine scenarios and sensitivities
    b. Determine capacity position
    c. Develop supplemental modeling inputs
3) Develop resource alternatives
4) Conduct and iterate modeling
5) Analyze results
6) Initial synthesis of results and determine preliminary PCA
    a. Validate resource adequacy

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b. Conduct risk assessment
c. Conduct environmental justice analysis
d. Conduct financial analysis
e. Verify grid reliability analysis

7) Synthesize results into final proposed course of action
8) File the IRP, and take part in the contested case

Throughout the IRP process, stakeholder engagement takes place. I will discuss in more detail parts of steps 1, 2c, 3, 4, 6 and 7. Witness Cejas Goyanes will discuss parts of steps 2c and 3, and Witness Manning will discuss parts of steps 2a, 2b, 4 and 5.

While the modeling process is visually depicted as linear, the nature of the process of IRP modeling is somewhat circular in nature, as certain steps of the process are iterative. This means results and information gathered from later steps in the process are required as inputs in some earlier steps or modeling process steps may be completed simultaneously. Information learned through implementing the modeling process may cause reexamination and incorporation of learnings into the iterative analytical process. As such, if the validation of the Preliminary PCA in step six results in a failure in any of the assessments, the team returns to earlier steps, incorporating the new or updated information. For example, if the resource adequacy modeling of the Preliminary PCA had results that didn't meet the reliability target then the team would have returned to step 4 and updated the input assumptions.

Q13. How was the first step, "review planning objectives," performed?

A13. The IRP team reviewed the planning objectives at the start of the IRP process to ensure that the team considered them throughout the entire IRP process. For example, we consider the "clean" planning objective during the modeling process related to carbon emission constraints and the "reliable and resilient" objective during the modeling process. The IRP planning objectives, Safe, Reliable and Resilient, Affordable, Customer Accessibility, and Clean, are described in more detail by Witness Leslie in her testimony. The team considers the planning objectives along with the least-cost optimized portfolios resulting from the IRP capacity expansion optimization. In determining the PCA, the Company weighs the cost of the plans with all considerations contained in the planning objectives to determine the most reasonable and prudent means of meeting the electric utility's energy and capacity needs based on the criteria set forth in MCL 460.6t. This is discussed further in section VIII of my testimony.

Q14. What is included in Step 2c, "Develop Supplemental Inputs?"

A14. In the Develop Inputs step, the IRP team gathered inputs from many sources including other witnesses in this case. Some of these inputs require the use of models run by third parties or third-party models run by the IRP team to produce inputs for EnCompass. These inputs are referred to as "supplemental inputs" due to the added analytics required to create or gather the data before using that data in the EnCompass model. The supplemental inputs that I will be describing in my testimony include the process to develop the ELCC values of solar and storage, obtained from the initial Resource Adequacy modeling. I will also describe the process for obtaining the inputs for Battery Energy Storage System (BESS) unit benefits. Finally, I will describe the process for developing the initial ITC scenarios that supported the Grid Modeling performed by ITC.

Q15. How was the third step, "develop alternatives," performed?

A15. The third step is to identify the resource alternatives or options the Company will model in the IRP process. To develop a reasonable and prudent plan, it is important to consider all feasible resource options to meet customer demand. The IRP team evaluated a multitude of technologies including natural gas and nuclear units, renewable generation, storage, and demand-side management resources among others. These technologies are called "alternatives." Some of the alternatives considered are emerging technologies and I discuss these and the process the Company used to select which emerging technologies to include in the IRP modeling in Section II. The costs and operating parameters of each alternative were inputs to the analysis. In this IRP, the Company used technology cost and operating data (i.e., fixed and variable O&M, size, efficiency) from publicly available data from a variety of sources. This is covered in more detail by Witness Cejas Goyanes in his testimony.

Q16. How was step 4, "conduct modeling," completed?

A16. 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 (described in Section III) and Grid Reliability (Transmission, Subtransmission, and Distribution) modeling (described in Section V). The main capacity expansion modeling (IRP optimization) was performed with the EnCompass model. The team used it to generate portfolios that consisted of different alternatives for each scenario and sensitivity in turn. A portfolio represents the resource plan the model determines to be the optimal portfolio based on market assumptions and resource alternatives. Modeling is discussed in more detail by Witness Manning in her testimony.

Q17. Can you explain the different models used in the IRP process and which witnesses are supporting each model?

A17. Yes, as part of the overall IRP process and step four in the IRP process, the team used several modeling tools in the different process steps. Table 1 shows a list of the models used and the witnesses in this case who will be supporting each in their testimony.

Table 1: Models used in the IRP Process

IRP process step	Model and Description	Run by	Witness(es)
2	Aurora – market fundamentals	Siemens	Manning
2	DER VET™ – Battery Ancillary services	DTE Electric	Mikulan (section IV)
2	SERVM - ELCC determination	Astrapé	Mikulan (Section III), Carden
2	SERVM - Flexibility Benefit	Astrapé	Mikulan (Section IV), Carden
6	SERVM - Resource Adequacy	Astrapé	Mikulan (Section VIII), Carden
4	Transmission models	ITC	Roy
4	Distribution models	Sargent and Lundy	Musonera
4	EnCompass	DTE Electric	Manning
6	Aurora – stochastic risk	Siemens	Mikulan (Section VII)
6	Financial Analysis	DTE Electric	Lepczyk, Uzenski, Willis
6	EPA Environmental Justice Screening and Mapping	DTE Electric	Marietta

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	Tool (EPA EJSCREEN 2.0) and EPA Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool		

Q18. What aspects of the IRP process are examined in step six, "Initial Synthesis of Results and Determine Preliminary PCA?"

A18. Step 6 examines various considerations following steps 4 and 5, in which least-cost build portfolios are determined. In addition to the EnCompass model results, which produced least-cost optimized portfolios for each scenario and sensitivity, the Company performed several other assessments and considered several other factors, including the planning objectives, in determining the PCA. Stakeholder feedback was also considered in the development of the PCA. As discussed by Witness Leslie, stakeholders desire a PCA that provides reliable and affordable power from a diverse mix of cleaner energy resources including solar, wind, storage, and natural gas. The other assessments considered in this step include the Resource Adequacy modeling iterative step to verify that the PCA is Resource Adequate is discussed by Witness Carden; the Risk Assessment as discussed in my section VII; the Environmental Justice Analysis as discussed by Witness Marietta; the various Financial Analyses as discussed by Witnesses Lepczyk, Uzenski, and Willis; and the final verification of the Grid Reliability Modeling as discussed by Witness Roy in their respective testimonies. In section VIII, I discuss the incorporation of these various assessments into the Synthesis of the Final PCA.

Q19. How was the "conduct risk assessments" stage handled in the sixth step of the Overall IRP process?

A19. Five risk assessment methodologies were used to review the feasibility of the proposed course of action: stochastic economic risk analysis, stochastic resource adequacy analysis, application of the planning principles, evaluation of key inputs, and scenario and global sensitivity analysis. Scenarios and sensitivities are discussed by Witness Manning in her testimony, and the remaining risk analyses are discussed in Section VII.

Q20. What was step 7, "Synthesize Results into Final PCA," based on in the IRP process?

A20. I describe the process the Company used to develop the PCA based on the planning objectives and the additional assessments performed in Section VIII of my testimony. After the preliminary PCA has been developed, there are five separate assessments that we conduct to ensure that the preliminary PCA considers the results of the assessments. If the preliminary PCA does not incorporate one or more of these assessments, then the preliminary PCA will be adjusted and checked again to see if the criteria are met for each of the five assessments. If the preliminary PCA meets the objectives, then it becomes the final 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 is aligned with the Company's planning objectives. The criteria for each of the five assessments in step 6 and the Witness supporting each are listed in Table 2.

Table 2: IRP Assessment Criteria for validating the PCA

Step	Assessment Objective	Witness(es)
Verify Preliminary PCA through Resource Adequacy Modeling	Meets LOLE of 1 day in 10 for critical years	Mikulan, Carden
Conduct Risk Assessment	PCA is determined to be low risk option compared to other alternative plans	Mikulan
Environmental Justice Analysis	PCA reduces overall CO_2 and other emissions including identified vulnerable communities	Marietta
Conduct Financial Analysis	PCA optimizes financial impacts to customers	Lepczyk, Uzenski, Willis
Verify Preliminary PCA through Grid Reliability Modeling	PCA is not significantly different from initial grid reliability studies performed and meets grid reliability	Roy

Q21. What is the PCA?

A21. The resulting PCA is presented below. The Company has divided the PCA into three time periods: the first five years, 2023-2027 then years six through ten, which covers 2028-2032. Then, the last ten years cover 2033-2042. The last ten years of the plan are more likely to change than the first 10 years as the Company files future IRPs, emerging technologies develop further, updated information becomes available, and market conditions and considerations evolve.

The first five years of the Company's PCA (2023-2027) include the following:

- Renewables – 800 MW of solar
- Battery storage – 240 MW
- Belle River – retires the plant on coal and converts it to a 1,270 MW natural gas peaking resource, one unit at a time in 2025 and 2026

- Energy Waste Reduction (EWR) – 2% annual savings in 2023 and an average 1.6% annual savings for the first five-year period, consistent with the maximum amount of achievable potential as identified in the EWR 2021 Statewide Potential Study (EWR Statewide Potential Study)
- CVR/VVO – 15 MW

Years six through ten of the PCA (2028-2032) include the following:

- Renewables
  - Solar – 3,600 MW
  - Wind – 1,000 MW
- Battery storage – 520 MW
- Monroe Units 3 and 4 retire in 2028 – 1,535 MW
- EWR – an average 1.2% annual savings, consistent with the maximum amount of achievable potential as identified in the EWR Statewide Potential Study
- CVR/VVO – 23 MW

Finally, the last ten years (2033-2042) include:

- Renewables
  - Solar - 2,100 MW
  - Wind - 7,900 MW
- Battery storage – 1,050 MW
- Retirement of Monroe Units 1 and 2 in 2035 – 1,531 MW
- Belle River natural gas peaking resource retirement by 2040 – 1,270 MW

- Low or zero carbon, dispatchable 946 MW placeholder resource in 2035, currently identified in this IRP as a CCGT with CCS
- EWR – an average 1.6% annual savings, consistent with the maximum amount of achievable potential as identified in the EWR Statewide Potential Study

The Company expects that as we get closer to 2035, the actual mix of resources to replace the capacity from the second two units of Monroe will likely be different from what the model currently selected. Market conditions may vary from the assumptions used in the modeling, thereby affecting timing and resource selection. Resources needed to replace capacity in 2035 will be determined in future IRPs.

Q22. Which IRP process steps involved technical stakeholder collaboration and input?

A22. For the purposes of the 2022 IRP, technical stakeholders (stakeholders) include individuals with an understanding of the technical aspects of an IRP and organizations that are often active participants in DTE Electric's regulatory proceedings. Stakeholder collaboration and input played a role in each of the six steps listed in Table 3. The Company also held public open houses, invited the public to submit comments and emails, and conducted customer research to create additional opportunities to gather feedback to inform the Company's analysis and decision-making. Witness Leslie further describes these outreach efforts and how the feedback was considered in the IRP.

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1 **Table 3: Stakeholder Input**

IRP Process Step	Stakeholder Input
1. Review Planning Objectives	• Utilized stakeholder input from the 2019 IRP and feedback on planning objectives during development of 2021 Distribution Grid Plan
2. Develop Inputs	• Inputs, three scenarios, 13 sensitivities, and four load sensitivities from order in Case No. U-18418 resulting from the 2017 collaboratives • Inputs and one scenario from order in Case No. U-20633 on the Carbon Reduction (CR) scenario • Coordination with EGLE on environmental analysis and specific portfolios analyzed • Reviewed the data inputs at the technical workshops and addressed questions and comments • Inputs from stakeholders on the stakeholder scenario (STAKE) and associated sensitivities • Four additional sensitivities submitted by different stakeholders
3. Develop Data Assumptions	• Reviewed resource alternative assumptions at the technical workshops and encouraged questions, comments, feedback, and recommendations • Stakeholder-requested sensitivities • BESS benefits feedback obtained from stakeholders at technical workshops • Astrapé presented on Resource Adequacy modeling and ELCC determination at a technical workshop, answered stakeholder questions, and took feedback
4. Conduct Modeling	• Utilized new EnCompass Modeling tool selected after feedback obtained at 2020 Modeling Software collaborative • Discussed modeling process at six technical workshops and obtained feedback • ITC and the Midcontinent Independent System Operator (MISO) presented at a technical workshop, answered stakeholder questions and took feedback • Held discussions with MPSC staff on modeling process

5. Initial Synthesis of Results and Determine Preliminary PCA	• Used input from the 2017 Certificate of Necessity (CON) and 2019 IRP • Utilized comments received through stakeholder engagement and public outreach process including public open houses, emails and comments, technical workshops, and voice of the customer research • Considered initial impacts of the Inflation Reduction Act (IRA) • Incorporated results from Environmental Justice and health impact analysis
6. Synthesize Final PCA, identify proposed course of action	• Considered results from stakeholder identified scenario and sensitivities • Considered stakeholder and public comments and feedback as noted in Step 5

Q23. Do you have examples of stakeholder suggestions or comments that have been incorporated in the IRP modeling process?

A23. Yes. The Company devoted one of the scenarios to a stakeholder suggested scenario, where the assumptions and inputs were submitted and agreed upon collaboratively by the stakeholders that attended the session with facilitation from the Company at a stakeholder workshop. The stakeholders that were part of this scenario-development process included parties that participated in the Company's last electric rate case and the 2019 IRP proceeding or expressed interested in participating. It should be noted that the resulting stakeholder scenario, or STAKE, was not representative of the views of all participating stakeholders but represented the majority of the stakeholders present at the workshop. In addition, 12 sensitivities were run on the stakeholder scenario and two other sensitivities developed and submitted by the stakeholders run on other scenarios. The Company considered the results of these scenarios and sensitivities in the synthesis of IRP results and the PCA. The modeling incorporates input from technical analysis and

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collaboration with ITC, who provided insights and costs on potential transmission impacts of generation alternatives. In addition, the Company held two stakeholder workshops on battery benefit modeling as discussed by Witness Leslie. The enhanced battery modeling incorporated many stakeholder suggestions obtained during these two stakeholder workshops. In her testimony, Witness Manning provides additional examples of how DTE Electric considered stakeholder input in the modeling process. Details on the battery modeling is covered in section IV in my testimony and discussed further by Witness Manning in her testimony.

SECTION II: EMERGING TECHNOLOGY AND TECHNOLOGY SCREENING

Q24. What is the process for identifying emerging technologies?

A24. The IRP team worked with the DTE Electric Energy Supply team to identify potential technologies to evaluate for inclusion in the IRP optimization modeling using the EnCompass model. DTE Electric also used an engineering consultant, Black and Veatch, to help us understand the characteristics of the various technologies, the carbon reduction potential, the approximate costs, and technical maturity of each. Black and Veatch presented several emerging technologies including long duration energy storage, hydrogen, carbon capture and sequestration, and small modular nuclear reactors as part of the public open houses hosted by the Company. In addition, they prepared two-page overviews of these technologies for reference which are hosted at dtecleanenergy.com. More information on the public open houses and the emerging technology overviews is available in the Public Outreach Report sponsored by Witness Leslie, Exhibit A-1.4.

Q25. Can you discuss some of the emerging technologies, their key features and potential applications?

A25. Yes. While various emerging technologies were evaluated as detailed above, for the purposes of this discussion, I focus on the following:

- Mid-to-long duration storage (generally > 4 hours), such as flow batteries and compressed air energy storage
- Nuclear Technologies - Advanced nuclear and small modular nuclear reactors (SMR) - (Gen III+/Gen IV)
- Low Carbon Fuels – Liquid or gaseous fuels for generation; hydrogen (also serves as energy storage)
- Carbon Capture and Sequestration (CCS)
- Hydrogen fuels for generation

Mid-to-long duration storage includes thermal, electrochemical (batteries with new, different, potentially low-cost chemistries), mechanical (gravitational, pumped storage), and chemical (includes hydrogen). These types of storage are generally more modular installations and, aside from pumped hydro, are generally less mature than lithium-ion (Li-ion) batteries that provide up to four hours of storage). Longer duration storage technologies will become more important as more renewables and shorter-duration storage units (4 hours) are added to the grid in the next decade or so. (See the testimony of Witness Carden and his sponsored Exhibit A-5.1 for more detail.) In the near-term, shorter duration storage is more economic than longer duration storage. After more renewables are built, longer duration storage may become more economic. See Section III of my testimony for more detail on the interaction of storage and renewable resources. Since many of these storage resources are emerging, the Company used eight- and ten-hour Li-ion storage as a proxy for mid-to-long duration storage. We anticipate this will change in future IRPs as these technologies continue to mature and evolve.

The **Nuclear Technologies** considered were Advanced Nuclear and SMR technologies. New nuclear resources are available 24/7 and are considered firm dispatchable and capable of load following, which pairs well with intermittent renewables. The first national SMRs are expected to be in commercial operation by 2030. The IRP team used SMR technology as a proxy for all new nuclear technologies based on its slightly more mature Technical Readiness Level (TRL).

Low Carbon Fuels – Liquid or gaseous fuels for generation including biodiesel and renewable natural gas. In general, we found these fuels to be very high priced and generally used in the carbon offset market ($20/MBTU or higher, compared to natural gas prices in the $3.50- $6.00/MBTU range in the MIRPP scenarios). Please refer to Exhibit, A-4.3 levelized cost of energy (LCOE) results for additional analysis.

Hydrogen fuel for generation is also considered a low carbon fuel, as CO_2 is not a byproduct of combustion. While there are different types, or "colors" of hydrogen based on how it is produced, green hydrogen produced in electrolyzers using power generated by renewable resources can be stored and then used as fuel in a gas fired resource. Green hydrogen production could be modeled and utilized as a form of energy storage, which could be economic in the future as more renewables are built. Today, costs are quite uncertain and large- scale applications are not mature.

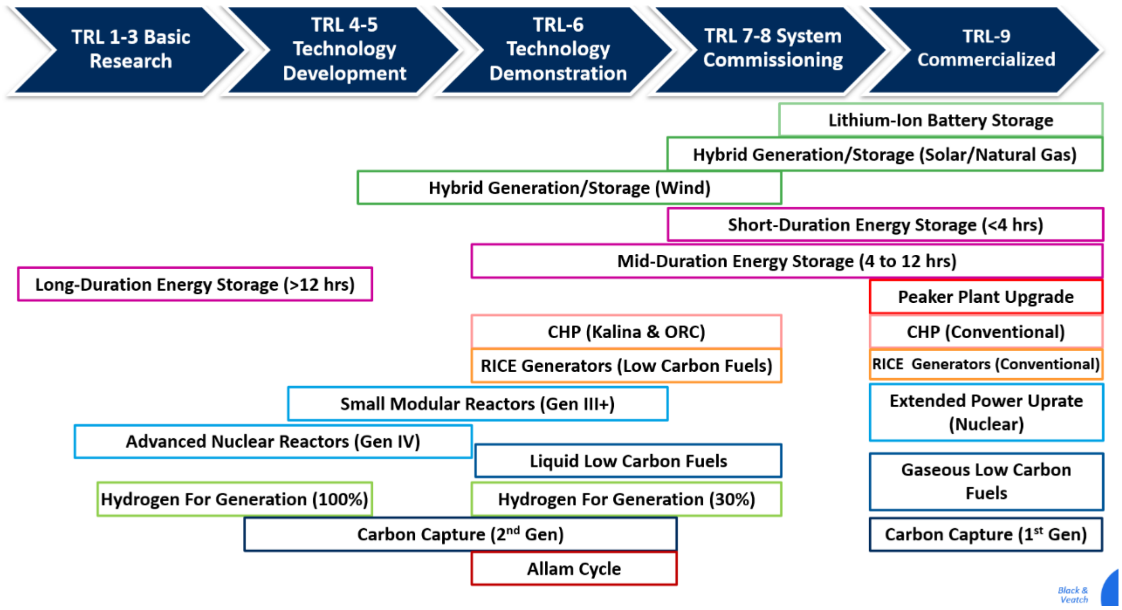
Accordingly, the Company did not model green hydrogen production in this IRP although it may be considered in future IRPs.

<u>Carbon Capture and Sequestration (CCS)</u> can be applied to CO_2 emitting fossil fuel units such as coal or gas combined cycle gas turbines (CCGT). Costs are lower if this technology is integrated into the initial design of the plant as opposed to added as a retrofit at a later date. A CCGT with CCS plant is expected to capture between 50-98.5% of the carbon it emits. In this IRP, the Company modeled a CCGT with CCS (90% and 98.5%) as a very low carbon emitting, firm dispatchable resource option. Tax incentives, such as those available in the Inflation Reduction Act (IRA), could lower the cost of this technology. Direct Air Capture (DAC) is a technology that pulls CO_2 out of the air instead of from a CO_2 emitting fossil unit. Since the CO_2 is not as concentrated with DAC as with a CCGT with CCS, DAC is more costly on a per ton basis to remove.

Q26. Can you discuss the readiness of these emerging technologies?

A26. As shown in Figure 2, the mentioned technologies are at various stages of maturity or technical readiness for incorporation in the IRP. This figure uses the term Technical Readiness Level (TRL) which was adapted from the US National Aeronautics and Space Administration (NASA), who first defined it in the 1970's, as "Technology Readiness Levels are a type of measurement system used to assess the maturity level of a particular technology. Each technology project is evaluated against the parameters for each technology level and is then assigned a TRL rating based on the project's progress. There are nine technology readiness levels. TRL 1 is the lowest and TRL 9 is the highest." [1]

Figure 2. Technical Readiness Level of various technologies



Technologies on the right side of this figure are more advanced and typically in use today. Technologies on the left side are furthest from maturity and cost and operational data is uncertain. Costs and operational data become more certain the further to the right, as the TRL increases. When considering similar technologies to offer to the EnCompass model for the IRP optimization, the Company preferentially chose alternatives at higher TRL.

While the first half of the 20-year proposal relies on known, available technologies, we expect costs and commercially available technologies will change before implementing the second half of the plan, which includes the retirement of the last

[1] Tzinis, Irene. "Technology Readiness Level." NASA, https://www.nasa.gov/directorates/heo/scan/engineering/technology/technology_readiness_level, accessed October 20, 2022.

1,531 MW of coal fired generation at Monroe in 2035 and the 1,270 MW Belle River natural gas peaking resource by 2040 and is more uncertain. In the second 10 years, we expect to see several of the technologies that are currently at lower maturity levels (lower TRL) become more mature through further research, development, and demonstration with a corresponding increase in associated TRL. We expect the plan for the second 10 years will evolve in future IRPs as these emerging technologies continue to evolve. In other words, in future IRPs, we anticipate that different or more evolved technologies could be selected over the technologies we are modeling now.

Q27. Are there factors that could change the timeline for commercialization of these?

A27. Yes, federal policies such as tax credits, grants, loan guarantees, as well as research, development, demonstration, and commercial activity (RDD&CA) could affect the pace, cost, and performance of these emerging technologies. The Department of Energy (DOE) has a number of initiatives[2] underway to bring down the cost and enhance the capabilities of hydrogen, long-duration storage as well as CCS. The IRA includes incentives for clean energy, including hydrogen, CCS, and other emerging technologies. State-level clean energy and climate policies could also play a role. Another factor is implementation progress of these technologies by utilities and other industry players that helps drive learning and investment behavior.

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[2] "Energy Earthshots Initiative." ENERGY.GOV, Accessed October 15, 2022. https://www.energy.gov/policy/energy-earthshots-initiative.

Q28. What is DTE Electric doing to support the advancement of emerging technologies?

A28. DTE Electric is actively monitoring trends in emerging technology cost and performance and is pursuing partnerships and pilots to gain experience with technology applications. Participation in industry groups such as Electric Power Research Institutes (EPRI) Low Carbon Research Initiative (LCRI) will also provide opportunities for monitoring developments and sharing of research and lessons learned. In addition, the Company is benchmarking, identifying opportunities for potential DOE grants, and monitoring industry developments. One example of this is the Company's participation on the Low Carbon Peer Group (LCPG) Steering Committee. The LCPG was founded in 2021 as a way for utilities to collaborate with each other and with vendors and original equipment manufacturers (OEMs). The overarching goal is to identify, prioritize and accelerate the deployment and adoption of low carbon firm (dispatchable) resources. A coordinated, cross-functional evaluation of emerging technologies will assist utilities to execute net-zero goals, while reducing costs and maintaining or improving reliability. Collaborating will ensure multiple peer utilities can have access to pilots, demonstrations and deployments across different regions and various technologies.

Q29. Does Michigan have relative advantages to support the deployment of emerging energy technologies and related innovation?

A29. Yes. Michigan has a unique combination of geologic, logistic, and economic factors related to emerging energy technologies that the state and the Company could leverage, and which could bring benefits to the economy, customers, and the environment. In addition to having the nation's number one working gas storage capacity[3,4], Michigan's geology is expected to be able to store hydrogen and CO_2. The Mount Simon sandstone formation, which extends into Michigan, is ideal in terms of depth, thickness and rock characteristics (permeability and porosity) to permanently store large quantities of CO_2 in an economic manner[5]. Michigan also has access to bedded salt formations, which allow for economic underground storage of hydrogen[6]. Michigan is an international logistics hub, has world-renowned industrial and engineering expertise, is home to the automobile industry with rapidly growing battery manufacturing capabilities, and has long-standing nuclear expertise. The Governor's Executive Directive 2020-10, as well as voluntary commitments by major corporations, including DTE Electric, to reach net zero carbon emissions with interim goals can also help drive innovation and actions to mitigate climate change.

Q30. How can low carbon or clean, dispatchable generation and other emerging technologies complement renewable energy and lithium ion batteries?

A30. While renewable resources such as solar and wind are an economic source of clean, carbon free power, they are not dispatchable and only generate energy when the

[3] Michigan working gas storage, MPSC. "About Michigan's Natural Gas Industry", 9. Michigan.gov, August, 2019. https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/nat-gas/About_Natural_Gas.pdf#page=9%202019%20MPSC%20report.

[4] Michigan working gas storage, According to the report "with about 671 billion cubic feet (19 billion cubic meters) of working gas capacity, EIA statistics show that Michigan has more storage than any other state."

[5] Mount Simons formations, THE MIDWEST REGIONAL CARBON SEQUESTRATION PARTNERSHIP. "Phase I Final Report", 112-118. NETL's Energy Data eXchange, December, 2005 https://edx.netl.doe.gov/dataset/mrcsp-phase-i-final.

[6] Hydrogen, Mongird, Kendall, Vilayanur Viswanathan, Jan Alam, Charlie Vartanian, Vincent Sprenkle, and Richard Baxter. "2020 Grid Energy Storage Technology Cost and Performance Assessment", 7. Pacific Northwest National Laboratory, December, 2020. www.pnnl.gov/sites/default/files/media/file/Hydrogen_Methodology.pdf.

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sun is shining or the wind is blowing. There are certain times of the year when solar is not plentiful in Michigan, like during shorter, cloudier days in the winter. Similarly, Michigan wind has its lowest capacity factors during the sunny, high heat months of June, July, and August.

As adoption of transportation and building electrification increases to support carbon reduction across multiple sectors, we will consider changes in charging patterns in future IRPs as additional data becomes available. The Reference (REF) scenario forecast presented by Witness Leuker in his testimony shows that DTE Electric's winter peak is projected to grow faster than the summer peak at a rate of 0.9% and 0.3% compounded annual growth rate (CAGR) respectively through 2042.

Storage resources can help shift excess renewable energy to when it is needed, however unless the storage resources are longer in duration and capable of shifting the excess renewable energy weeks, months, or seasonally, then low carbon or zero dispatchable resources will likely still be needed to ensure a reliable system with high amounts of wind, solar, and batteries. In its May 2022 report, "The Future of Energy Storage[7]," the Massachusetts Institute for Technology (MIT) studied a range of energy storage capabilities that could be available by 2050 to support deep decarbonization of the grid. The report found that "Energy storage and other emerging technologies can play a critical role balancing supply and demand and

[7] Future of Energy Storage, Armstrong, Robert. "The Future of Energy Storage." MIT Energy Initiative, June 3, 2022. https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf accessed October 20, 2022

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provide other services needed to keep a decarbonized electricity system reliable and cost effective." (p. xi)

In addition, the National Renewable Energy Laboratory's August 2022 report, "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," analyzed scenarios to reach net zero grid by 2035 and found expanded nuclear, a range of storage technologies, CCS, and transmission would be needed with the exact technology mix and costs determined by research and development, manufacturing, and infrastructure investment decisions. The lead author observed "There are several key challenges that we still need to understand and will need to be addressed over the next decade to enable the speed and scale of deployment necessary to achieve the 2035 goal."[8] See section III for more detail on how the Company considered resource adequacy in the IRP with the changing resource mix over the next 20 years.

Q31. Will DTE's efforts to continue to reduce emissions from its electric operations through increased renewable energy and advancement of emerging technologies also help drive decarbonization of other sectors such as transportation and industry?

A31. Yes; the deployment of emerging technologies will not only reduce emissions in the electricity sector but also support broader, economy-wide decarbonization efforts. With increased reliance on electricity, it is essential that supply is reliable

[8] NREL Path to Net Zero, Geocaris, Madeline. "Exploring The Big Challenge Ahead: Insights on the Path to a Net-Zero Power Sector by 2035." NREL, August 30, 2022. https://www.nrel.gov/news/program/2022/exploring-the-big-challenge-ahead-insights-on-the-path-to-a-net-zero-power-sector-by-2035.html., accessed October 20, 2022

and resilient throughout the net zero transition. Emerging technologies are expected to be an essential part of such electricity supply.

Q32. Emerging technologies also include vehicle-to-grid (VTG) applications. Can you briefly discuss VTG technology and how it may play a future role in the Company's planning processes?

A32. Automakers are investing heavily in the electrification of the transportation sector, including passenger vehicles and fleets, and a variety of partners, including DTE Electric and other utilities, that are investing in charging infrastructure. With advancement in technologies and charging infrastructure, VTG applications may offer new opportunities to serve as a grid resource by providing capacity, energy, and other benefits. Improvements in the technologies, controls, communications, and grid infrastructure still need to be made to enable this emerging technology but it is important to monitor developments with VTG applications. VTG applications will likely be considered in future IRPs.

Q33. Is DTE proposing near-term strategies in the IRP to be able to leverage emerging technologies for the benefit of customers longer term?

A33. Yes. The Company's approach is two-fold. First, as outlined in the PCA, the Company is leveraging existing assets such as the Ludington pumped storage facility and continuing to invest in proven, cost-effective technologies such as four-hour lithium-ion BESS, wind, and solar photovoltaic (PV) and demand side management (EWR, demand response (DR), conservation voltage reduction/volt-var optimization (CVR/VVO)) to meet resource needs in the near-term. The PCA also includes the Belle River natural gas conversion as a low-cost option to support additional coal retirements and maintain local reliability and resource adequacy while emerging technologies evolve. The Belle River conversion, with an expected retirement date in 2039, allows the Company to take advantage of potential cost reductions and performance improvements of emerging technologies over the next decade.

Second, the Company is monitoring emerging technology trends and pursuing pilot opportunities to gain direct experience with new but commercialized technologies such as the Slocum BESS pilot proposed in the pending rate case (Case No. U-20836) and supported by Witness Morren. The PCA provides additional lithium-ion battery storage applications (240 MW) in the first five years. The hydrogen (H_2) pilot to blend green hydrogen using an electrolyzer and above-ground storage at BWEC, proposed in Case No. U-20836, would also provide opportunities to gain first-hand experience with hydrogen production and storage technologies. As noted above, DTE Electric is monitoring opportunities for external funding, such as DOE grants, tax incentives, and technical assistance support, to help offset costs, reduce risks, and build strategic industry relationships.

DTE Electric's approach maintains adaptability to learn and capitalize on technologies as they mature and new ones develop during this dynamic time in the energy industry.

Q34. Are there different pathways for incorporating emerging technologies into DTE Electric's net zero future?

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A34. Yes. The Company's IRP study period and modeling includes the time period 2023 to 2042 so does not extend to 2050. Nonetheless, the modeling portfolios show a broad range of futures and associated emission trajectories that can begin to inform options for reaching net zero by 2050. Existing generation, including natural gas (Bluewater Energy Center) and the recently expanded Ludington pumped storage combined with other resources, including the conversion of Belle River from coal-fired power plant to a natural gas peaking resource along with additional investments in renewable energy and lithium-ion battery storage can address energy and capacity needs in the late 2020s through the early 2030s with the retirement of the first two units at Monroe. To reach net zero and support the retirement of the second two units at Monroe, emissions would need to be reduced through additional investments in renewable energy as well as some combination of clean fuels blending (e.g., hydrogen), nuclear, mid-to-long duration energy storage, and CCS. Carbon offsets and DAC are also potential options to reach net zero.

Q35. Can you describe the first step in the process for selecting emerging technologies to include in the IRP optimization?

A35. Yes. The Company evaluated the technical feasibility of certain emerging technology alternatives in the first step of technology screening. This step allowed the elimination of alternatives that were not yet commercially available at scale, had high cost or scarce fuel supply at scale, or that had geographic limitations. Table 4 shows the list of the emerging technologies considered, whether they were eliminated and why.

Table 4: List of Emerging Technologies Considered

Technology	Technological / Feasibility Pass	Reason for Eliminating
Advance Nuclear Reactors (Gen IV)	No	Maturity (TLR 1-5) vs SMR (TRL 4-6)
Allam Cycle	No	Maturity (TLR 6)
BESS (excluding Li-ion chemistries)	No	Current estimates of cost, cycle life, size and maturity
Carbon Capture, Sequestration and Utilization	Yes	
Concentrating Solar Thermal	No	Geography: Climate lacking completely cloudless day
Direct Air Capture	No	Does not provide energy or capacity; out of scope for IRP
Flow Batteries	No	Maturity vs Li-ion batteries
Geothermal	No	Lack of geographic sites
Hydrogen Fuels for Generation	Yes	
Hydropower	No	Geography
Kalina Cycle (CHP)	No	Maturity (TRL 6-8)
Long Duration Storage (e.g. thermal, gravitational)	No	Current estimates of cost, cycle life, size and maturity
Microturbines	Yes	
Offshore Wind	No	Maturity vs Onshore Wind
Organic Rankine Cycle	No	Maturity (TRL 6-8)
Reciprocating Internal Combustion Engines (RICE)	Yes	
Renewable Diesel	No	Scarcity of economic fuel
Renewable Natural Gas	No	Scarcity of economic fuel
Small Modular Reactors	Yes	
Thermal Storage	No	Maturity at scale vs Li-Ion, lower round trip efficiency vs Li-Ion batteries
Waste Heat to Power	No	Extremely site specific
Water Wave/Tidal	No	Maturity

Q36. Can you provide more detail on the SMR alternative technology as it was modeled in EnCompass?

A36. Yes. The SMR alternative was modeled as a proxy for new nuclear alternatives due to its TRL level of 4 to 6 as compared to Gen IV having a TRL of 1 to 5 as shown in Figure 2. However, due to the assumption that the first SMR is expected to be online in 2028 to 2030, and a construct and operate license is expected to take 7-8 years, the SMR technology is limited to selection in the EnCompass model in 2035 or after.

Q37. What types of energy storage technologies did the Company evaluate as a part of its IRP?

A37. Besides the emerging storage technologies evaluated in the technical feasibility evaluation described above, additional mature storage technologies evaluated in terms of technical feasibility included new pumped hydroelectric storage, compressed air energy storage (CAES), and four different battery storage technologies (Li-ion, sodium-sulfur, lead acid, and flow batteries). Beyond the existing Ludington facility, deployment of pumped hydro[9] was screened out due to the geographical limitations of siting a new facility CAES[10] was screened out since its deployment is limited by the availability of suitable geologic formations and due to limited commercial experience in the United States. Since Li-ion batteries broadly represent the best-in-class storage technology considering ease of siting, cost, cycle life, system size, and technology maturity, the IRP team decided to offer Li-ion batteries in 3 durations: 4, 8, and 10 hours to the EnCompass optimization. These Li-ion batteries are considered a “proxy technology” in the IRP, meaning

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[9] Pumped hydroelectric storage uses electricity to pump water to a higher elevation. When required, water is released to drive a hydroelectric turbine.
[10] Compressed Air Energy Storage (CAES) uses electricity to compress air into confined spaces. When required, air is released to drive the compressor of a natural gas turbine.

they represent battery chemistries other than Li-ion and non-battery storage technologies as well. Especially for the longer duration storage, we expect non-battery storge options such as thermal storage or gravitational storage to mature and become lower cost than Li-ion in future IRPs. When it is time to build the storage units selected in the PCA, the Company will issue an RFP that is open to different types of battery storage chemistry and/or non-battery storage, and select the best fit based on the needs of the Company at that point in time.

Q38. What was the second step in the IRP technology screening process?

A38. After the technical feasibility of emerging technologies was completed (Table 4 above), the technologies that passed this screen went to the second step or economic screening of the technology screening process using the levelized cost of energy (LCOE) model. In this step, these technologies were combined with the non-emerging (mature) technologies and were screened together. The technologies, both emerging and mature, passing the LCOE assessment then went to the EnCompass model. LCOE screening is discussed in more detail by Witness Cejas Goyanes.

SECTION III: RESOURCE ADEQUACY STUDY USED IN IRP MODELING

Q39. What is Resource Adequacy and what was the purpose of the Resource Adequacy modeling?

A39. Resource adequacy is ensuring that DTE Electric has enough resources to serve its customers in all hours of the year across a range of reasonably foreseeable conditions with the Company's resources specified in a portfolio. Resource adequacy is related to reliability and ensuring the Company's fleet has enough

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resources to meet its customer's needs. If the DTE Electric fleet was not "resource adequate" to a target reliability standard, there is a higher probability of customer interruptions (i.e., load shed, due to lack of supply).

The purpose of the Resource Adequacy modeling was two-fold. Early in the IRP process, the Company wanted to determine input assumptions for the Effective Load Carrying Capability (ELCC) of solar and storage to use in the IRP modeling. The ELCC of a generating resource is a measurement of that resource's ability to produce energy when the grid is most likely to experience electricity shortfalls. ELCC is typically expressed as a percentage of a resource's capacity, for example, a 100 MW solar plant that has an ELCC of 30% could make a 30 MW contribution towards reliability requirements.[11] The ELCCs were determined based on initial resource adequacy modeling. As described in Section I, this was part of Step 2, "develop inputs."

Resource adequacy modeling was also performed later in the IRP process. As part of Step 6, after a preliminary PCA was identified, one of the assessments performed was determining if the preliminary PCA was resource adequate. This assessment was completed using resource adequacy modeling. Both of these steps will be discussed in more detail.

Q40. Who performed the Resource Adequacy Modeling?

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[11] ELCC, Specht, Mark. "ELCC Explained: the Critical Renewable Energy Concept You've Never Heard Of." Union of Concerned Scientists, October 12, 2020. https://blog.ucsusa.org/mark-specht/elcc-explained-the-critical-renewable-energy-concept-youve-never-heard-of/.

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A40. The Company hired a consultant, Astrapé Consulting, to run the SERVM model, the same model used by MISO[12], to determine both the ELCC input assumptions based on initial resource adequacy modeling and to validate that the preliminary PCA was resource adequate. Witness Carden discusses more details on the studies performed in his testimony and Exhibit A-5.1.

Determination of ELCC for solar and storage using the SERVM Resource Adequacy model

Q41. What was the process of using the SERVM model to determine ELCCs for the EnCompass Model?

A41. There were several steps to this process:

1. In 2021, the IRP team provided inputs and data to Astrapé to run the SERVM model to determine the ELCCs of solar and storage to be used for modeling purposes. The inputs included assumptions on the resources in MISO Local Resource Zone (LRZ) 7, historical resource operational data, and market price assumptions. As Witness Carden describes in his testimony, Astrapé ran the SERVM model to generate ELCC results for solar and storage that DTE Electric could use for its IRP modeling.
2. Astrapé presented the SERVM results in the form of a calculator that enabled the IRP team to utilize the SERVM model results effectively. The ELCC calculator computed the ELCC for solar and the ELCC for storage as a function of the amount of total MW of solar and total MW of storage installed in LRZ 7.

[12] SERVM Model: https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf, page 5, accessed October 20, 2022

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3. The IRP team used the ELCC calculator to generate tiered ELCC assumptions for solar and tiered ELCC assumptions for storage that we input into the EnCompass model.

Q42. How were the capacity accreditations for the various resources determined for input into the EnCompass model?

A42. Each resource modeled in the EnCompass model has a "firm capacity" associated with it. The 2022 MISO accreditations of the existing resources, except for existing solar, were used in all years. All solar ELCCs, including existing and approved solar in the starting point, were assumed to be the same as new installed solar selected by the model. For new solar and new storage (battery) resources, tiered ELCCs were derived using the ELCC calculator provided by Astrapé, as described below. For new thermal resources (e.g., CCGT, CT), the MISO class average was used. For new wind resources, the LRZ 7 class average ELCC was used.

Q43. Why are solar and storage resources forecasted ELCCs different from thermal resources?

A43. Thermal units are considered to be firm dispatchable units, which means aside from random and planned outages, these resources are available when they are needed to produce energy to serve our customers' loads. On the other hand, solar and storage units are both considered energy limited, that is, a solar resource's output depends on the weather conditions or for storage, the state of charge, to be available to serve customers' loads when called upon.

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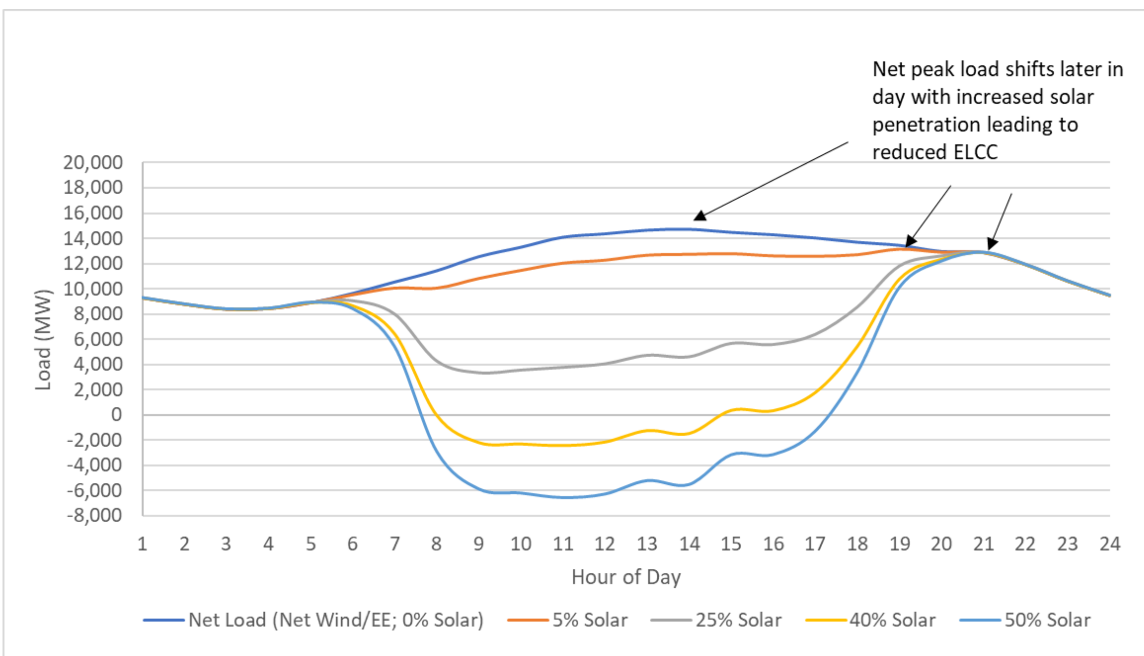
The DTE Electric forecasted peak occurs around 5 PM in July. Currently, MISO's accreditation of a new utility scale solar unit is currently 50% of nameplate capacity, reflecting expected output at the time of the gross system peak.[13] As solar penetration increases, the "net peak" should be considered instead of the peak. In this case, net peak is the gross LRZ 7 load less the renewables production by hour. As more solar resources are built, net peak will occur later in the day, as the sun continues to go down in the evening hours, reducing the solar contribution to cover the net peak. Pushing the net peak out further in the day, when solar units produce less power, reduces the ELCC of solar. This phenomenon is illustrated in Figure 3, a sample July day.

Figure 3. LRZ 7 Net Peak Shifts at Higher Solar Penetration



[13] MISO solar accreditation. "Planning Year 2022-2023 Wind and Solar Capacity Credit", 1. MISO, January, 2022.
https://cdn.misoenergy.org/2022%20Wind%20and%20Solar%20Capacity%20Credit%20Report618340.pdf

Some battery storage resources can serve reliability needs by storing solar power when it is plentiful earlier in the day and then discharging that energy at peak or later as the net peak is shifted out. However, as battery storage penetration increases, storage must begin discharging earlier and continue to discharge until late in the evening to serve remaining load. This implies that mid-to-long duration storage capability is needed to supply the same ELCC. Conversely, the same duration storage resource will show a declining ELCC at higher penetrations of storage build.

Q44. How are the solar ELCCs related to the storage ELCCs?

A44. Solar units and storage units are synergistic with respect to their reliability contribution during times of critical system need. Solar energy steepens the net load shape, allowing shorter duration storage resources to support reliability. Storage resources flatten the net load creating more opportunity for solar to serve in critical reliability periods. This synergy is reflected in ELCC values for solar and storage being higher when built in tandem than when built in isolation. This is also known as a diversity benefit.

Q45. How are storage units' ELCC impacted in LRZ 7 due to the Ludington Pumped storage facility?

A45. The large, approximately 2,200 MW Ludington facility, is already in place shifting energy from when it is low cost to when it is higher cost. The usable "duration" of Ludington is approximately 8-12 hours. Due to the presence of Ludington, the incremental value of any storage added to LRZ 7 will be determined with Ludington

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dispatching as well, so the value of added storage may be lower than it would be if Ludington was not already an integral part of the LRZ 7 resource mix.

Q46. How were the ELCCs input into the EnCompass model?

A46. The EnCompass model is capable of handling a tiered ELCC (firm capacity) input. For example, the first 1,000 MW of installed capacity of a resource could have an ELCC of 80%, the second 1,000 MW installed capacity of that resource an ELCC of 60%, and the rest could be at 50%. Each ELCC tier is input as a resource block, with a corresponding ELCC percentage and installed capacity (MW) amount. The ELCC percentage applies from the input installed capacity at that block to the next installed capacity block. The last block applies from the installed capacity of that block and greater. See Figures 4 and 5 for the ELCC tiers as they were input into EnCompass for solar and storage, respectively.

Figure 4. Solar Tiers modeled in EnCompass

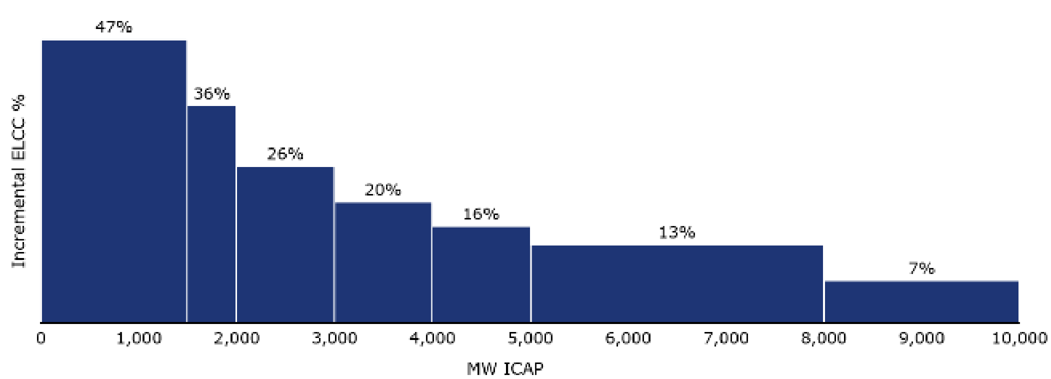
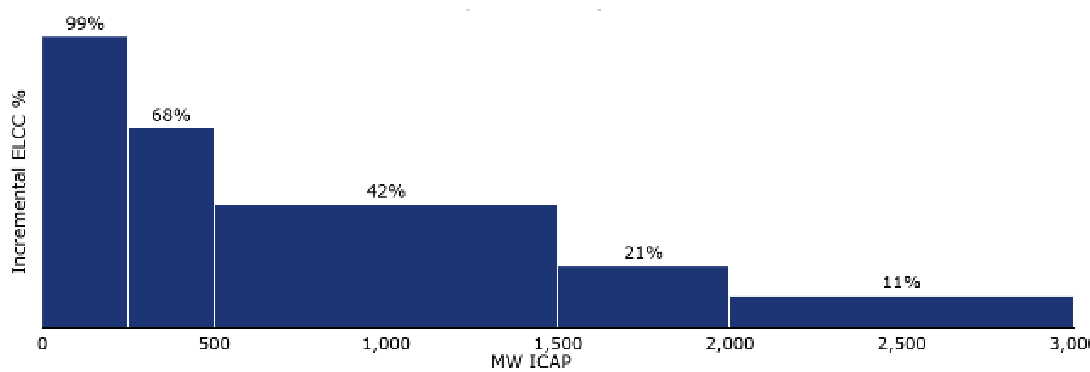


Figure 5. Storage Tiers modeled in EnCompass



Q47. Can you describe how the company used the ELCC calculator to determine solar and storage ELCCs for this IRP?

A47. Yes. The ELCC calculator requires two inputs to determine the forecasted ELCC of LRZ 7 solar and the ELCC of LRZ 7 storage:

1. The total amount of solar that has been installed in LRZ 7
2. The total amount of storage that has been installed in LRZ 7

The EnCompass model is determining the optimal amount of solar and storage to build for DTE Electric. Therefore, assumptions must be made about the amount of solar and storage that is installed for the rest of LRZ 7 because the SERVM model run to determine the ELCCs included all of LRZ 7.

Q48. What assumptions were made about the amount of solar that was installed in the rest of LRZ 7?

A48. The Company decided to assume that the rest of LRZ 7 builds mirrored exactly what the DTE Electric build assumptions were for solar and storage. Reasoning for this was that the market forces across LRZ 7 would be similar; if solar and storage were getting selected in the DTE Electric service area part of the zone, those same

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market forces would drive a similar selection in the rest of the zone. Additional support for this assumption was that the proposed Consumer's IRP indicated a significant ramp up of solar over the next two decades[14,15].

Q49. You indicated that an assumption on the total amount of storage for LRZ7 is needed for the ELCC calculator to determine the ELCC for the solar. What assumptions were made about the amount of storage installed in LRZ 7?

A49. The Company looked at two levels of storage adoption – low and high in the ELCC calculator. As shown in Figure 6, the higher storage level, as shown by the dotted orange line, corresponds with higher Solar ELCCs as shown by the solid orange line. The blue solid line demonstrates that at lower levels of storage (shown by the dotted blue line), the corresponding Solar ELCCs are also lower. Therefore, when increased levels of storage penetration were assumed in LRZ 7, the ELCCs for solar were higher, and with lower assumed storage adoption levels, the Solar ELCCs were lower.

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[14] 2021 CMS IRP, Michigan Public Service Commission. "Settlement Initial Brief of Consumers Energy Company", pg. 5. LARA, May 25, 2022. https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y00000317wnAAA.

[15] 2021 CMS IRP, Direct quote from reference "as outlined in the PCA, which provides for the addition of approximately 8,000 MWs of solar resources by 2040"

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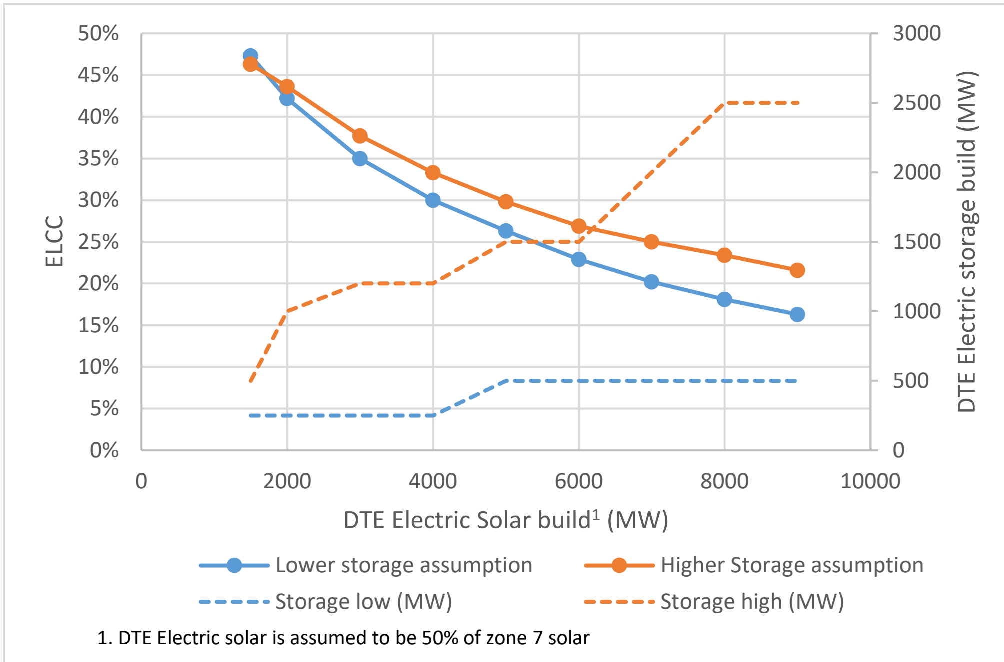
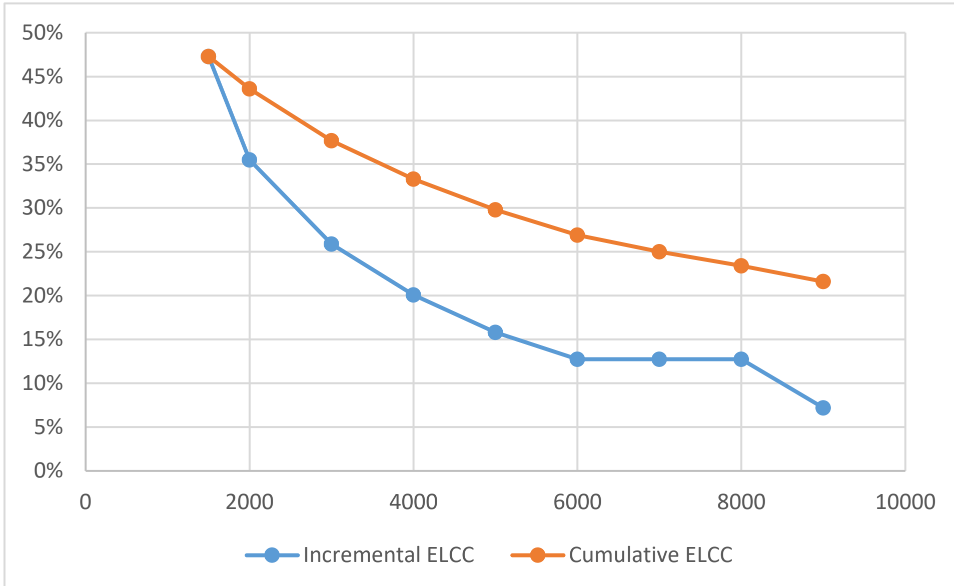
Figure 6. Cumulative Solar ELCC assumption as calculated



Q50. What were the resulting solar ELCC assumptions used in the EnCompass model?

A50. Based on the results of the ELCC calculator as shown in Figure 6, the Company used the higher solar ELCC results in its EnCompass. Figure 7 shows the incremental and cumulative solar ELCCs for the tiered solar installed capacity blocks.

Figure 7. Solar ELCC as modeled in EnCompass



Q51. What was the Solar ELCC assumption used in the EnCompass model at penetrations below 1500 MW of solar?

A51. For simplicity, an ELCC value of 47.3% was used for all solar in the EnCompass model up to 1500 MW. This was done to maintain consistency across the different tier levels developed using the ELCC calculator. This does differ from the current MISO accredited value of 50%, however the impact of this simplification is negligible because the majority of the first 1,500 MW of solar is existing or approved (865 MW) that is in the starting point of every model run, so the lower 47.3% value is only being used to value new the first 635 MW incremental solar resources in the optimization for the first 1-2 years.

Q52. How were the storage ELCCs determined for input into the EnCompass model?

A52. The storage ELCCs were determined using the same process as the solar ELCCs.

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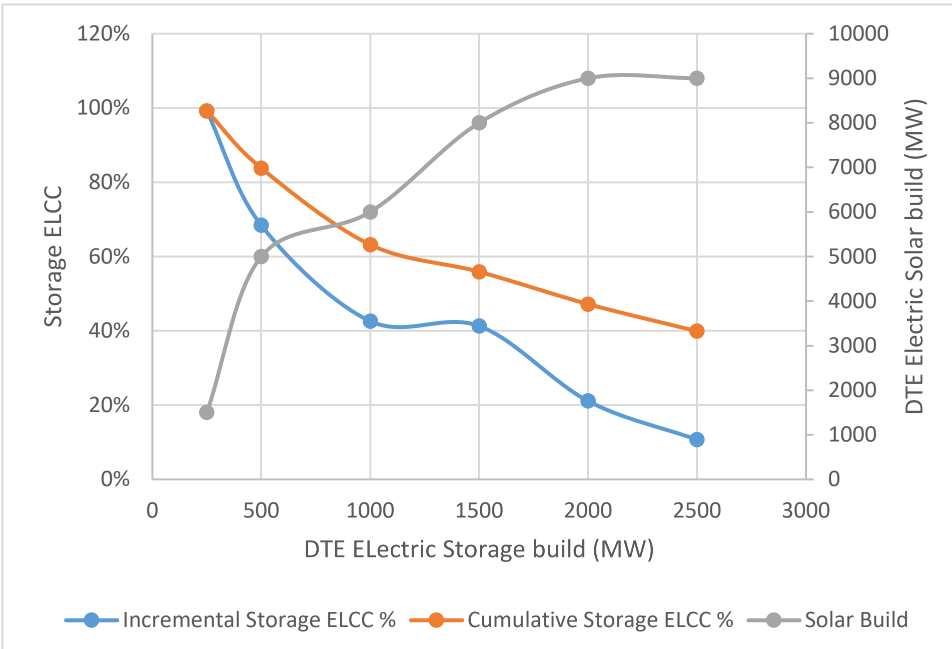
As with solar, we assumed that the rest of LRZ 7 installs the same amount of storage as DTE Electric and that the amount of solar installed is high. The resulting ELCC of the storage is shown in Figure 8:

Figure 8. Storage ELCC as modeled in EnCompass



Q53. Why did you assume high amounts of solar when establishing the ELCC for storage and vice versa?

A53. It is likely that the optimized solar and storage builds selected by EnCompass will not match the high solar levels that were used to establish the storage ELCC tiers, and the high storage level used to establish the solar ELCC tiers. We intentionally preset these levels on the high end to not bias the model against selecting either solar or storage because of lower tiered ELCCs. However, pre-setting both solar and storage to the higher levels may result in misaligned solar and storage ELCCs in the EnCompass model results. To address this possibility, the preliminary PCA was modeled in the Resource Adequacy model to validate the PCA as resource adequate. This final SERVM run corrected any ELCC differences that may have arisen in the EnCompass modeling due to using the high assumptions to set the tiered ELCCs for solar and storage. This second pass through the resource adequacy model is discussed in more detail later in my testimony.

Q54. Why were the wind ELCCs assumed to be the MISO LRZ 7 average instead of using a tiered ELCC for wind?

A54. There were a few reasons:

1. When IRP modeling started in late 2021, solar and storage were expected to be the primary resource additions in the State in the next decade. This was primarily based on the Company's recent projects and the Consumers Energy Proposed PCA.
2. Establishing a system of three variables is too complex for modeling, both for the modelers to set up and the EnCompass model to handle. The EnCompass run times increase as more tiered firm capacities are used, going from two firm capacity tiers to three would increase the run time of each model run.
3. The EnCompass modeling selected solar and some storage before additional wind in the majority of scenarios in the first 10 years of the study period. Wind becomes more relevant in the second ten years of the study period where we expect the renewables build to possibly change as noted previously in my testimony. In the REFRESH scenario where wind was being selected earlier in the study period, it was limited to 200 MW per year

before 2035. Please see the testimony of Witness Hernandez for more details on renewable build limits. As I discussed in Section II of my testimony, the first five to ten years of the study period relies on known, commercially available technologies, where the second half of the study period, when wind is being selected, is not as definitive.

Since we can only pick two out of three of solar, wind, or storage to evaluate with tiered ELCCs, we chose to leave wind as the constant value and establish tiers for solar and storage ELCCs. This is because it was either being selected later in the study period or constrained to a lower build assumption.

Q55. Why are you not assuming the current MISO accreditation for the solar and storage ELCCs?

A55. The current MISO accreditation for new solar is 50%, which is representative for today, at lower solar penetrations in LRZ 7. The current MISO method of ELCC attribution to solar and storage appears to overestimate the reliability contribution, as it does not capture the declining marginal ELCC effect of increased penetration levels of renewables on the system. MISO has acknowledged this consideration and is reviewing[16] and working to update the non-thermal accreditation methodology, as discussed by Witness Burgdorf in his testimony. In addition, LRZ 7 is currently at less than 2% solar,[17] so the net peak (as shown in Figure 3) has not yet shifted to later in the day when solar generation will be lower. However, IRPs are forward

[16] Solar and storage ELCC's. MISO. "MISO's Renewable Integration Impact Assessment (RIIA)", 29-30. MISO, February, 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf.
[17] Solar percentage in LRZ 7, Astrapé's Base of 781 MW solar (Exhibit A-5.1, Table 28), which includes some approved by not yet installed solar

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looking and the performance of resources up to 20 years into the future must be considered.

Reliability, as measured by Resource Adequacy modeling, captures how customers' loads are met in every hour, separate from the actual MISO accreditation. By considering the results of the initial Resource Adequacy modeling, and specifically how solar and storage perform, the Company is putting forward a reliable PCA by fully considering the changes to the net peak due to the changing mix of resources.

Q56. Do you believe there any other resources where the current MISO accreditation method may not fully capture the true ELCC of those units?

A56. Yes, according to some recent industry studies, the UCAP resource accreditation of firm dispatchable resources, as currently attributed by MISO, may overestimate firm resource class reliability contribution relative to a perfect resource capacity equivalent (i.e., relative to an ELCC value) due to cumulative system outage effects such as:

- Outage variability
- Weather dependent outages
- Fuel supply related outages
- Correlated outages due to common mode failure

In addition, MISO recently issued a new accreditation methodology, for thermal units with requested start dates in planning year 2023/2024, that addresses some of these issues. This change was approved by FERC August 31, 2022, which would

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have been too late in the IRP modeling process for the Company to incorporate the new resource accreditation methodology into the EnCompass model, even if we had all the required assumptions. However, as Witness Burgdorf describes in his testimony, the necessary details from MISO are still pending. To address potential ELCC accreditation changes, we are addressing this issue in the IRP risk analysis (Portfolio metric evaluation, capacity position). See section VII for details on the analysis performed.

Resource Adequacy modeling conducted as part of the iterative Reliability modeling on the Preliminary PCA

Q57. How is resource adequacy measured?

A57. Resource adequacy is measured in units of Loss of Load Expectation (LOLE). The MISO standard for LOLE as well as the standard of many other Independent System Operators (ISO) in North America is 1 day in 10 years, or 0.1 LOLE. See the testimony of Witness Burgdorf for additional details on LOLE.

Q58. How was resource adequacy determined in this IRP?

A58. Once the preliminary PCA was determined, the Company requested Astrapé Consulting, using the SERVM model, to determine if the preliminary PCA was resource adequate. Astrapé conducted a resource adequacy assessment for MISO Local Resource Zone ("LRZ") 7 (modeling DTE Electric and non-DTE Electric load and resources dispatched within a single region). Depending on the results, the preliminary PCA may have needed to be updated to ensure resource adequacy. Please see Witness Carden's testimony and Exhibit A-5.1 for more details.

Q59. What were the results of the Resource Adequacy analysis run on the preliminary PCA?

A59. Astrapé ran the Resource Adequacy Analysis on years 2028 and 2035 of the preliminary PCA. These two years were chosen because they are the years with the largest expected capacity changes; 2028 is the year of the first two Monroe unit retirements and 2035 is the year of the second two Monroe unit retirements. The Company provided Astrapé the specific build plans in these two years. The results of the Resource Adequacy modeling are shown in Table 5.

Table 5: Resource Adequacy Modeling Results on Preliminary PCA

Year	LOLE results	SERVM Surplus Capacity (UCAP)
2028	0.04 or 1 day in 25 years	308 MW
2035	0.02 or 1 day in 50 years	403 MW

The modeling results showed that the preliminary PCA was resource adequate with an LOLE of 0.04 in 2028 and an LOLE of 0.02 in 2035; both lower than the MISO standard of 0.1. The LRZ 7 system with the preliminary PCA would be expected to have sufficient resources to meet the MISO resource adequacy standard. This analysis assumed a distribution of weather conditions consistent with those experienced over the past 40 years. Another run was completed with more extreme weather assumptions. These results are discussed with the Risk assessment in section VII.

Q60. What is the difference between the preliminary PCA and the Final PCA?

A60. After the preliminary Resource Adequacy modeling results were obtained, the results of the REFRESH scenario, which incorporated the IRA tax credits, were incorporated into the synthesis of results that inform the PCA. The PCA was changed as a result of this REFRESH scenario. Changes on the Final PCA from the preliminary PCA include additional wind in 2028 and additional storage, wind, and solar in 2035. These changes are shown in Table 6.

Table 6: Change in Resources under Final PCA compared to Preliminary PCA

Years	Solar	Wind	Storage
Total change 2023-2028 (ICAP)		+100 MW	
Total change 2023-2028 (UCAP)		+12 MW	
Total change 2029-2035 (ICAP)	+1,153 MW	+1,172 MW	+1,200 MW
Total change 2029-2035 (UCAP)	+358 MW	+141 MW	+435 MW

Table 6 shows the results in terms of both ICAP and UCAP using the tiered ELCCs for storage and solar. A total of 358 MW solar, 153 MW wind (12 MW in 2028 and 141 MW in 2035), and 435 MW of storage were added on a UCAP basis to the preliminary PCA to get to the Final PCA. While the marginal ELCC of wind, solar, and storage declines with higher penetration, it remains positive as the addition of any generation will improve net reliability. The UCAP change reflected in Table 6 is an estimate of net incremental contribution to system reliability after all interactions with other resources are considered. Therefore, the plan remains resource adequate and does not need to be re-verified in the SERVM model. Had the mix of resources changed other than adding additional resources, an additional Resource Adequacy run may have been warranted depending on the extent of the changes. Due to the additional resources, the Final PCA is more resource adequate than the preliminary PCA run in the SERVM model. Refer to testimony of Witness Carden for details.

SECTION IV: BENEFITS ATTRIBUTED TO STORAGE RESOURCES

Q61. In its February order on the Company's 2019 IRP, what direction did the Commission provide to the Company related to the consideration of storage benefits?

A61. The Commission recognized limitations with existing capacity expansion modeling tools to fully consider certain benefits of energy storage resources. While the Commission declined to require a particular modeling tool or methodology, it directed the Company to consider in this IRP a quantification of storage benefits including flexibility, grid support, and ancillary services.[18]

Q62. How did the Company determine its approach to modeling storage and the associated storage benefits?

A62. The Company held two technical workshops on energy storage modeling with stakeholders and leading experts as part of the 2022 IRP process. The first session included discussion led by industry experts from Argonne National Laboratory, Pacific Northwest National Laboratory, EPRI, 5 Lakes Energy, and Anchor Power Consulting to inform and educate stakeholders in general, and in particular DTE

[18] Case No. U-20471, February 20, 2020 Order, p. 74.

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Electric. The purpose of the first workshop was to identify insights to guide the Company on how to model the benefits of storage, including in-depth discussion of several modeling tools. After this session, the Company evaluated several tools including DER-VET™ from EPRI, BSET by Pacific Northwest National Laboratory, and EnCompass. The second battery storage session was held a few months later and provided stakeholders the results of that evaluation, the selection of the modeling tool, DER-VET™, and the approach the Company was taking to model battery storage and the associated benefits.

Q63. Can you describe the DER-VET™ model?

A63. Yes. The DER-VET™ model is an open- source model by EPRI and is used to determine various value streams of different types of distributed energy resources including storage resources. The Company used this tool to determine the value of spinning reserve and frequency regulation of a 60 MW battery block. These values were then input into the EnCompass model.

Q64. Can you describe how new battery storage resources were modeled in the EnCompass model?

A64. Yes. The battery resources' capacity value and price arbitrage value is being captured by the EnCompass model. Capacity value reduces or defers investments in additional generation capacity. Price arbitrage value comes from the BESS storing energy produced during periods of low demand/prices and selling during periods of higher demand/prices. We modeled new storage resources somewhat differently than the other resources to capture additional BESS value streams. The differences are as follows:

1. Spinning Reserve and Frequency regulation (also known as Regulating Reserve), both ancillary service products that MISO administers, were first determined using the DER-VET™ model, and then the market benefits of those ancillary service products were input into the EnCompass model for the first 180 MW of new battery storage systems.
2. A hybrid solar plus storage system was offered in the EnCompass model. The benefit of this alternative is that if the battery is charged exclusively by the tied solar units, then the battery is eligible for the solar investment tax credit (ITC). As discussed in section VII, the majority of the IRP modeling was conducted before the enactment of the IRA; the IRA includes an ITC for stand-alone battery storage facilities (as discussed by Witness Cejas Goyanes), lowering the revenue requirement of this alternative.
3. A flexibility benefit was included for battery alternatives in the Emerging Tech (ET) scenario.

Approaches 1 and 3 are discussed in more detail below.

Q65. You indicated that the market benefits of spinning reserves were calculated for battery energy storage resources. What is spinning reserve?

A65. Spinning reserve is extra generating capacity that is available by increasing the output of generators that are already connected to the power system. Traditional generators must already be running and have room to ramp up quickly to cover spinning reserve. Batteries can also provide spinning reserves and can frequently do so more efficiently and effectively than traditional resources. Battery resources have the ability to provide power to and from the grid within milliseconds, whereas thermal resources on the system need to leave headroom to ramp up, which utilizes them less efficiently.

Q66. You indicated that the market benefits of frequency regulation were calculated for energy storage resources. What is frequency regulation?

A66. Changes in supply and demand for electricity can have a major effect on the grid, which is designed to operate at a frequency of 60 Hz. For instance, if there's more demand for electricity than there is supply, then frequency will fall. Conversely if there is too much supply, frequency will rise. Another term that can be used to describe frequency regulation is "grid support."

Q67. Why were the ancillary benefits limited to 180 MW of energy storage?

A67. The market for frequency regulation reserves in MISO is not large, as only a limited number of resources are required to quickly respond to moment by moment imbalances of supply and demand. Typically, MISO procures up to 400 MW of regulation reserves to support system needs. Similarly, the market for spinning reserve in MISO is 900-1,000 MW. [19] If we add these together, the total ancillary market that batteries could serve is around 1,300-1,400 MW. DTE Electric is approximately 10% of MISO based on our load share. 10% of the ancillary market is around 130-140 MW. Since we are modeling batteries in blocks of 60 MW, we set the max amount of batteries that would get the ancillary benefit to three battery blocks, or 180 MW.

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[19] Short Term Reserve MISO. "Getting Started with Short-Term Reserve", 10. MISO, November 2, 2021. https://cdn.misoenergy.org/20211102%20STR%20Workshop%20Presentation%20(IR010)600624.pdf., accessed October 21, 2022

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Q68. What were the values input into the EnCompass model for the different battery blocks modeled?

A68. We modeled batteries of three different durations: 4 hours, 8 hours, and 10 hours. The DER-VET™ values from the REF Scenario used in the EnCompass model are shown in Table 7 below.

Table 7: Battery benefits as determined by DER-VET™

Duration	Spinning Reserve	Frequency Regulation	Total Ancillary Services benefit
	Values in levelized $/kW		
4	$3.66	$69.97	$73.63
8	$4.50	$68.28	$72.78
10	$4.62	$67.93	$72.55

Q69. How did you determine the ancillary services markets to use in the DER-VET™ model?

A69. We determined a correlation between historical spinning and frequency regulation markets and the locational marginal prices (LMPs). This correlation was applied to the hourly LMPs for each market price scenario. The resulting spinning and frequency regulation markets were input into DER-VET™. Because the Company has several different market futures across the IRP scenarios and sensitivities, the ancillary services markets will vary as well. DER-VET™ had to be run around 40 times to address all the market, load, and battery duration combinations.

Q70. Did you determine the ancillary services value for the other non-battery resources?

A70. Yes, we ran two sensitivities using the EnCompass model that included the ancillary services markets of frequency regulation and spinning reserve for all units capable of participating in these markets. The purpose of these runs was to provide an alternate view of the ancillary value, as well as provide an equal footing for all technologies in the ancillary market.

In all of the modeling completed, aside from these two sensitivities, the benefits as determined by the DER-VET^{TM} tool were used as inputs into EnCompass as previously described. The DER-VET^{TM} tool utilizes ancillary market forecasts and makes a decision each hour on which market (spinning, frequency regulation, or energy arbitrage) to participate in based on economics, without regard to ancillary requirements or DTE Electric's 10% load share as discussed above. These requirements were accounted for in the EnCompass runs by limiting the amount of ancillary benefit batteries that could be added to 180 MW, so as not to exceed the Company's load share.

In contrast, when running the full ancillary market model, EnCompass was required to meet the Company's estimated load share for each ancillary service and determine the opportunity cost to pay each unit. The opportunity cost is what each unit must be paid to compensate it for participating in that particular ancillary market instead of the energy or other ancillary markets each hour. The main disadvantage of full ancillary market modeling in EnCompass is the increase in run time and inability to solve due to problem size. Due to the number of runs, it was infeasible to perform full ancillary modeling on every run.

The types of units that participated in some or all ancillary services modeled in EnCompass included gas units, peakers, Ludington, batteries, and coal units.

When the NPV from the EnCompass model runs with the full ancillary service and the run that used the DER-VET™ derived benefits were compared, the full ancillary service runs were more expensive[20]. The only inputs changed between these two sensitivities was the ancillary service setup. This is expected, since the full ancillary runs have to meet the Company's estimated load share percentage of the ancillary service requirement for each service modeled, whereas the other runs were allowed to select batteries with ancillary benefits (as determined by DER-VET™), but they were only selected when profitable. Whereas, fulfilling the ancillary service requirement was not necessarily profitable. This is evident by the fact that the full ancillary service run of REF_CASE_7B_Full_Ancillary selects four more battery units than the non-full ancillary run using DER-VET™ derived benefits (see Table 8), and results in the higher NPV. Figure 9 shows the ancillary value by generation type.

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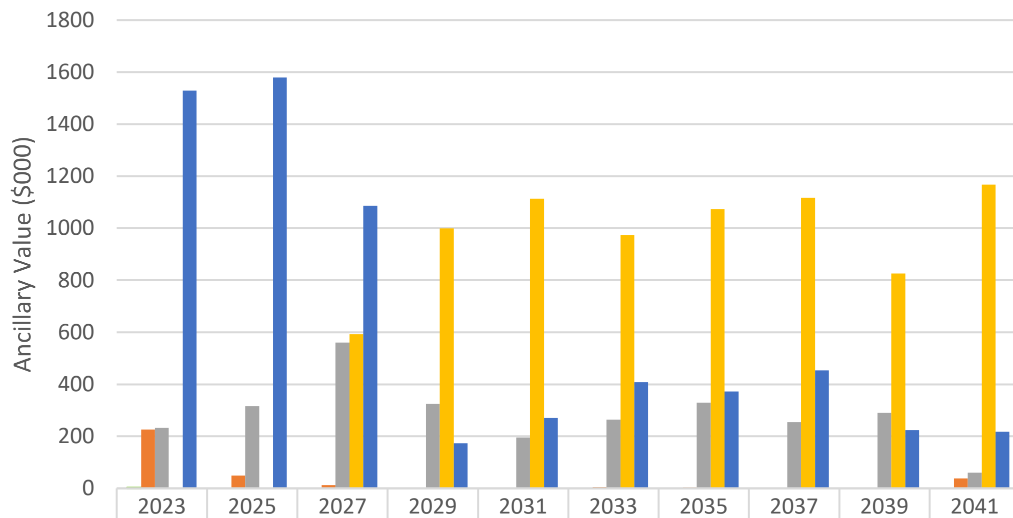
[20] In Witness Manning's testimony, Table 5, Run REF_BASE_FULL_ANC is $94 Million NPV higher than the REF_BASE and REF_FULL_ANC_CASE_7B is $103 Million NPV higher than the REF_Base. In Table 3, REF_CASE_7B_BLR25_26GAS_MNR28_35 is $88 Million NPV higher than the REF_Base. Therefore, REF_FULL_ANC_CASE_7B is $15 Million NPV higher than REF_CASE_7B_BLR25_26GAS_MNR28_35

Figure 9. Ancillary Value by Generation Type



	2023	2025	2027	2029	2031	2033	2035	2037	2039	2041
Coal:Conventional	3									
Gas/Oil:Combined Cycle	226	49	12	2	1	5	3	0	3	38
Gas/Oil:Steam Turbine	232	316	560	325	196	264	329	255	290	60
Storage:Battery			592	999	1114	974	1073	1117	825	1168
Storage:Pumped Hydro	1529	1580	1087	174	271	408	373	454	224	218

Another result seen in Figure 9 is that prior to 2026 the vast majority of the ancillary energy comes from the Ludington pumped storage units, but in 2026 and after, the batteries were selected. These new batteries then start to provide the ancillary energy. Additionally, batteries get selected earlier in the full ancillary run versus the other comparable run (2026 versus 2028, as seen in Table 8). This makes a case for battery additions earlier rather than later.

Based on these results, batteries are earning the most ancillary benefit value compared to other categories of resources. Additionally, it appears that both methods do a comparable job to each other to estimate this value.

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Table 8: EnCompass result comparisons 7B (MW build by year)

	DER-VET™ benefits				Full Ancillary		
Additions	**Solar**	**Wind**	**Storage**		**Solar**	**Wind**	**Storage**
2026					*100*		*60*
2027							
2028	*420*		*360*		*400*		*240*
2029	*2*						
2030		*254*				*179*	
2031	*1000*				*990*		
2032	*1000*				*1000*		
2033	*1000*				*1000*		
2034	*1000*				*1000*		
2035		*1000*				*1000*	
2036		*1000*				*1000*	
2037		*1000*				*1000*	
2038		*1000*			*100*	*900*	*60*
2039	*600*	*400*	*360*		*1000*		*600*
2040	*1000*		*600*		*1000*		*600*
2041		*1000*				*1000*	
2042		*1000*				*1000*	
Total	***6022***	***6654***	***1320***		***6590***	***6079***	***1560***

Q71. You indicated above that you reflected the flexibility benefit of battery storage in the IRP modeling. Can you describe what the flexibility benefit is?

A71. Yes. The use of intermittent resources such as wind and solar in an electric system causes an increase in the volatility of energy produced throughout the day, creating a need for a flexible system that can respond to rapid changes in the net load profile. Flexibility violations are the expected number of days per year where there is an imbalance in load and generation due to ramping constraints or required generator startup times (as opposed to loss of load due to a lack of system capacity). We expect the number of flexibility violations to increase over time due to increased net load volatility from adding renewables (both wind and solar) to the grid. In order to maintain the system's current level of flexibility (i.e., operate with the same expected value of flexibility violations prior to increased renewable adoption), additional levels of ancillary services (incremental load following reserves) are required, which adds to system operation costs. This is known as renewables integration costs. The integration costs also include fuel and other associated costs for ramping thermal units. Batteries are a flexible resource as compared to existing fossil units on the grid. Therefore, the incremental amount of ancillary services required to maintain baseline flexibility is expected to be less when assuming battery storage capacity compared to the system without battery storage capacity. This represents an incremental benefit to battery storage beyond its production cost savings associated with providing energy and ancillary services with an assumed baseline ancillary service requirement.

Q72. How did you determine the flexibility benefit?

A72. The Company hired Astrapé to determine the flexibility benefit using the DTE Electric resource adequacy models they already had built in SERVM. The SERVM model has the capability of simulating intra-hour studies (five-minute time intervals) to capture flexibility violations.

Q73. How is the flexibility benefit different from the ancillary battery benefits discussed earlier?

A73. The ancillary services market benefit is calculated on a static hourly ancillary market (that is, not changing with changing resource portfolios) and the flexibility benefit is determined from sub-hourly market cost differences resulting from portfolios with different amounts of renewables in them. Also, the flexibility benefit will apply to larger amounts of battery additions than the ancillary benefit previously discussed. The ancillary services market benefit of spinning and frequency regulation only applies to the first 180 MW of battery storage. The flexibility benefit applies to 500-965 MW of battery storage, depending on the number of additional renewables assumed. The DTE Electric level is assumed to be 50% of the Battery Storage penetration values for all of LRZ 7 shown in Table 8. The flexibility benefit is separately calculated, so it is not included with the ancillary services market benefit.

Q74. How did you apply the flexibility benefit, as determined by Astrapé, to the battery storage units modeled in EnCompass?

A74. We analyzed four different levels of renewables, including three different levels of solar and one level of wind as incremental resources added to LRZ 7. As described in more detail by Witness Carden in his testimony, using the SERVM model, Astrapé determined the integration cost with and without batteries at the four different renewable levels. The results from the flexibility study performed by Astrapé are shown in Table 9.

Table 9: Flexibility benefit

	4GW Incremental Solar	8GW Incremental Solar	14GW Incremental Solar	2GW Incremental Wind
Battery Storage Penetration (MW)	1,000	1,210	1,930	1,000
Integration Cost Without Battery ($/MWh)	1.82	2.64	2.96	2.28
Integration Cost With Battery ($/MWh)	0.09	0	0	0.22
Integration Cost Reduction ($/MWh)	1.73	2.64	2.96	2.07
Total Battery Flexibility Benefit ($M)	13.23	40.57	79.99	12.67
Battery Flexibility Benefit ($/kW)	13.23	33.41	41.38	12.67

The integration cost shown is reflective of the expected added production cost, including ancillary services, to the fleet associated with resolving the flexibility violations driven by the addition of renewables. The total battery flexibility benefit shown in Table 9 is this reduced integration cost from the batteries that were added to the model. The "benefit" or reduction to the integration cost can be distributed across the MW amount of batteries added. This battery benefit can then be applied in terms of $/kW per year cost reduction for the batteries.

Q75. How were the flexibility values applied in the EnCompass model?

A75. First, we determined an assumed build of LRZ 7 wind and solar. We assumed that LRZ 7 would reach 4000 MW of Solar by 2029, 8000 MW by 2032, and 14,000 MW by 2035 as shown in Table 10. Similarly, we assumed that LRZ 7 would reach an incremental 2000 MW of wind installed by 2033. We then applied the flexibility

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benefit from Table 9 in $/kW in those specific years. We interpolated leading up to and between the specific years. We then added the wind and solar flexibility benefits together and applied an escalation. The total flexibility benefit in $/kW of installed battery was then used in the EnCompass model up to the first 960 MW of new battery. We assumed that the second 960 MW of battery would get 50% of the flexibility benefit. Bold values indicate where the values taken from Table 9 are assumed in the timeline.

Table 10: Flexibility Benefit as modeled in EnCompass

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Solar LRZ 7 - assumed	1000	1000	1000	1000	1000	2000	2000	2000	2000	2000
Wind LRZ 7- assumed	-	-	200	200	200	400	400	400	400	-
Battery int benefit solar ($/kW)	3.31	6.62	9.92	**13.23**	19.96	26.69	**33.41**	36.07	38.73	**41.38**
Battery int benefit wind ($/kW)	-	0	2.11	4.22	6.34	8.45	10.56	**12.67**	12.67	12.67
Total with escalation applied ($/kW)	3.38	6.92	12.88	19.12	29.46	40.27	51.56	58.46	63.07	67.85

Q76. Why did you only apply the flexibility benefit to the MIRPP Emerging Tech scenario?

A76. Due to the Company deciding on the modeling methodology of the flexibility benefit later in the IRP process following consultation with stakeholders and industry subject matter experts, much of the EnCompass modeling for the REF and the MIRPP Business as Usual (BAU) and Environmental Policy (EP) scenarios was already completed by the time the results were available from Astrapé. Due to time constraints, the benefit was applied to the ET scenario, where batteries have lower capital costs to create the best possible case for batteries. The results of this ET run and the flexibility benefit were included in the synthesis of IRP results as discussed further in section VIII.

Q77. Is there uncertainty with respect to actual storage benefits that may be available in MISO?

A77. Yes, the specific dollar amounts of battery benefits that we modeled have uncertainty associated with them due to the following:

1. As discussed by Witness Burgdorf in his testimony, MISO is currently updating its ancillary services markets making future values uncertain.
2. Other flexible resources can also provide these services in MISO, such as natural gas combustion turbines and combined cycles. This suggests that there is a very real possibility that the value of these ancillary service products could further decrease if the market becomes saturated.
3. We did not model these ancillary values dynamically, that is, we assumed a static ancillary market with an assumed amount of ancillary services needed in MISO – not a dynamically changing market that updates as the fleet changes in MISO.

Q78. Do you expect modeling of battery storage benefits to continue to evolve?

A78. Yes. This was our first attempt to capture battery benefits in the IRP modeling process. While there are uncertainties associated with the quantified benefits reflected in the modeling and potential omissions and modeling limitations, the methodology used represents a reasonable estimate for capturing the flexibility and ancillary services benefits of battery storage. In future IRPs, we expect that the best practices across the industry in this complex area of modeling will evolve, our models will likely become more sophisticated, and additional MISO market data from battery pilots and storage units will be available. In addition, the Company expects to gain first-hand experience with different applications and use cases of battery storage (e.g., peaker replacement and solar plus battery as non-wires alternative) through several energy storage pilots. The deployment of additional battery storage by the Company and others will increase knowledge of the various services energy storage can provide and the evolving market participation models, which may in turn inform modeling approaches and tools. In future IRPs we expect to build on this initial storage benefit modeling effort and expand and improve modeling the benefits of storage in the IRP optimization.

SECTION V: ITC SCENARIOS USED IN TRANSMISSION MODELING

Q79. What was the purpose of the transmission modeling?

A79. The main purpose of the transmission modeling performed by ITC was to determine the impacts to the transmission system caused by changes to DTE Electric's generation fleet based on alternative retirement dates for the Monroe and Belle River Power Plants and to include both generation and transmission considerations in the IRP process. The impacts identified by ITC include the estimated costs of associated transmission network upgrades to support retirements and additions of generation resources under different scenarios or build plans. ITC performed a steady state transmission analysis (voltage and thermal) on three different scenarios across four different time frames, 5, 10, 15, and 20 years. This is described in further detail by Witness Roy in his testimony.

Through discussions with ITC it was determined that the cause of the largest expected changes to the transmission system would be the larger DTE Electric coal unit retirements (Monroe and Belle River), what generation replaced those units, as well as the point of interconnection (POI) of the replacement resources. In the ITC transmission modeling, we wanted to study the impact on the transmission system of the larger coal fired units' retirements. Specifically, we wanted to study the impact of three main levers:

1. How does a Monroe retirement affect the transmission system? Does staggering the Monroe retirement vs. a full plant retirement impact the transmission system violations observed and associated transmission costs?
2. How does a Belle River retirement impact the transmission system and what is the impact of converting Belle River to gas on the transmission system?
3. Is there a difference in the impacts on the transmission system based on the timing of the Belle River Retirements and the Monroe retirements?

The different build plans that ITC modeled are referred to as "ITC scenarios" to differentiate them from the IRP modeling scenarios involving different market futures as discussed earlier.

Q80. How did DTE Electric develop the three different ITC scenarios?

A80. The IRP team developed the ITC scenarios for use in the transmission modeling. Since the transmission modeling performed by ITC was started in January of 2022 and the IRP modeling was just commencing at this same time, a PCA had not yet been determined. First, we developed three retirement cases:

1. **ITC scenario-1:** Retire Belle River by 2028, then retire all four units of Monroe by early-2030s
2. **ITC scenario-2a:** Retire Belle River by 2028, then retire two units of Monroe by early 2030s and the other two units by mid-2030s
3. **ITC scenario-2b:** Convert Belle River to natural gas by 2028, then retire two units of Monroe by early 2030s and the other two units by mid-2030s. Retire converted Belle River by 2040.

The three scenarios described above were evaluated across four different years (i.e., 5, 10, 15 and 20 years)

Second, we determined the UCAP capacity needed by DTE Electric to replace the generation from the retired units. This was based on the 2021 initial resource adequacy analysis that was completed by Astrapé, and some preliminary EnCompass modeling that had been completed in 2021. We used the 2021 initial resource adequacy study, as described in Section III, to estimate the ELCCs of the solar and storage units in LRZ 7. We also used the EnCompass modeling to establish the mix of resources (solar, storage, and dispatchable CCGT proxy).

The total resources assumed in each of the three ITC scenarios was exactly the same in 2040, i.e., all builds get to the same spot, however the path getting there varied between the three cases or ITC scenarios. Refer to Exhibit A-2.1 for the retirement and replacement resource build assumptions.

Q81. How were the builds for the rest of LRZ 7 determined?

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A81. Similar to the LRZ 7 ELCC determination, as described in Section III, we assumed that the rest of LRZ 7 builds mirrored exactly what the DTE Electric build assumptions were for the solar and storage build. We also reviewed the proposed Consumers Energy's 2021 IRP for the proposed retirement dates of the Consumers coal units as well as to establish that Consumers was assuming a resource mix that included solar, storage, and a dispatchable CCGT proxy, similar to the Company's replacement generation. For the CCGT proxy build, we added the Covert plant to all cases, as it was part of the Consumers Energy proposed 2021 IRP PCA. The capacity shortfall in the rest of the zone, according to the proposed Consumers Energy IRP and DTE Electric's knowledge of the other entities in LRZ 7, was similar to the Company's projected capacity shortfall in the three cases. Therefore, the same replacement resources assumed for the Company were also assumed to cover the similar size capacity shortfall expected for the rest of LRZ 7.

Q82. Did you request another scenario, ITC scenario-3, to be studied?

A82. Yes. After the modeling was completed, the Company wanted to understand the impact of not having a dispatchable resource, the 1,350 MW CCGT-proxy, available after the retirement of the second two Monroe units to isolate the impact of this dispatchable resource on the transmission system.

Q83. How was the fourth build plan for ITC scenario-3 developed?

A83. Additional wind, solar, storage, and demand response was added to total 1,350 MW UCAP, the size of the CCGT-proxy unit that was removed for this analysis. The retirement assumptions for ITC scenario-3 were the same as ITC Scenario-1. ITC only modeled the 10-year case in the steady state study. See Exhibit A-2.1.

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Q84. Can you explain what the CCGT-proxy unit represents?

A84. Yes. The CCGT-proxy unit represents a firm fully dispatchable non-energy limited unit. The dispatchable unit could be a gas CCGT, gas CCGT with CCS, hydrogen fired CCGT, or SMR. In the transmission models, all of these types of resources run the same, fully available on the peak and shoulder models. The transmission model is agnostic as to the type of dispatchable unit represented.

Q85. Were transmission system upgrade costs included in the IRP cost comparisons between portfolios?

A85. Yes. The ITC modeling results included transmission system upgrade cost estimates of the initial three ITC scenarios. See testimony of Witness Roy for additional details on the transmission enhancement costs. These costs were used in the comparison of NPVRRs from the results from the EnCompass optimization across the different scenarios and sensitivities. See Table 11 for a cost comparison of the different transmission cost assumptions based on the Belle River Retirement dates. See Table 12 for a cost comparison based on different Monroe retirement dates.

Table 11: Transmission upgrade costs based on Belle River retirement dates

Belle River retirement years	NPV (M$) Transmission cost
24/25	$92
25/26	$88
2027	$81
2028	$78
2039 (after conversion)	0

Table 12: Transmission upgrade costs based on Monroe Retirement dates

Monroe retirement date	NPV (M$) Transmission cost
2031/2036[21]	$24
2032	$25
2035	$22
2039	$19
2028/2030	$29
2028/2032	$27
2028/2035	$26
2028/2039	$24
2030/2035	$25
2032/2035	$24
2032/2039	$22

Q86. Were distribution system upgrade costs included in the IRP modeling NPVRR results comparisons between different portfolios?

A86. Yes. The distribution system upgrade costs as determined in a Sergeant and Lundy study and supported by Witness Musonera, were used in the comparison of NPVs from the results from the EnCompass optimization across the different scenarios and sensitivities. See Table 13 for a cost summary of the different distribution and subtransmission cost assumptions.

[21] 2031/2036 were not modeled by the Company in the EnCompass model; they were the years assumed in the ITC modeling for the staggered Monroe retirement

Table 13: Distribution and subtransmission upgrade costs assumed

Monroe Retirement Year of final unit	NPV (M$) Distribution and Subtransmission costs
2028	$28
2030	$26
2032	$24
2035	$21
2039	$18

SECTION VI: CO_2 ACCOUNTING

Q87. Can you address the regulatory context for modeling CO_2 emissions in this IRP?

A87. Yes. As discussed by Witness Leslie, the Company complied with the Commission orders in Case No. U-20633 issued in February and September 2021 implementing Governor Whitmer's Executive Order 2020-10 with greenhouse gas emission reduction goals. Specifically, the Commission directed utilities filing IRPs in the near term (i.e., before the new IRP filing requirements and modeling parameters would take effect in 2023) to include modeling runs using high load growth under the EP Scenario and the effects of a 28 and 32% reduction in CO_2 emissions from 2005 levels by 2025.

Q88. How does the Company account for the impact of CO_2 emissions from market purchases and sales?

A88. In the 2019 IRP (Case No. U-20471), the Company explored several different methodologies to account for the CO_2 associated with the electricity used by our customers, whether sourced from DTE Electric owned generating assets, from the purchase of electricity in the market, or through purchased power agreements. We worked with EPRI to understand different methods that could be used to account for indirect CO_2 emissions. EPRI completed a study that described five methods of accounting for CO_2 emissions.[22]

Q89. Which method is the Company using in this IRP to account for CO_2 associated with the energy serving DTE Electric's customers?

A89. We use the net short approach to CO_2 accounting. Traditional utility CO_2 accounting usually only counts CO_2 from the company's fleet, and any CO_2 attributable to purchases or sales of power is ignored. In the net short method, the Company's generating units are divided into two groups: non-dispatchable and dispatchable.

In the traditional sense (and in different contexts in other sections in this filing), dispatchable refers to sources of electricity that can be used on demand and dispatched according to market needs. This is in contrast with non-dispatchable (intermittent) energy sources that cannot change their output in response to market needs, such as wind and solar, which are entirely dependent on the weather.

However, for the purposes of the net short carbon accounting method and using terminology consistent with EPRI's carbon accounting report discussed above,

[22] 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.

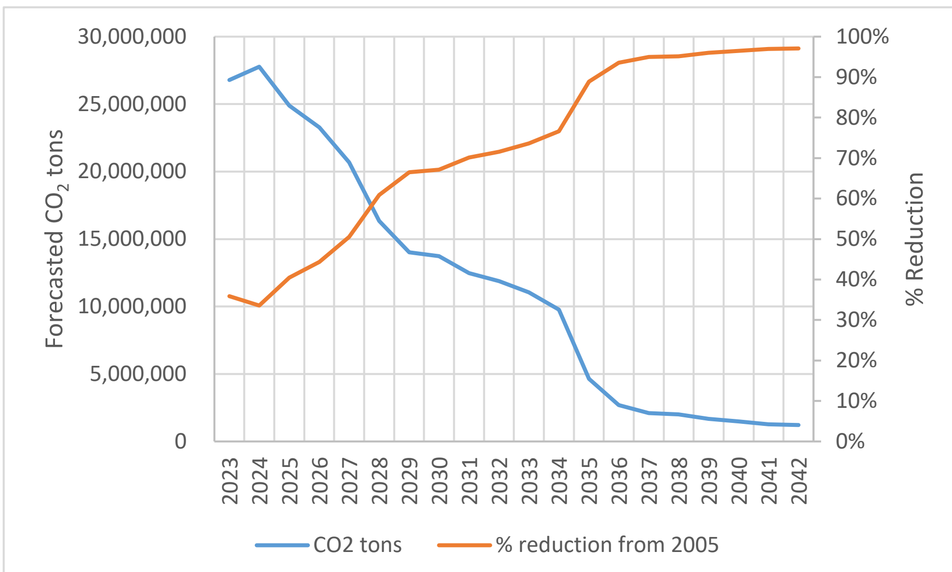
dispatchable refers to gas units, frequently on the margin serving the broader market ups and downs while non-dispatchable refers to the traditional baseload resources, renewables, and purchase contracts with specific assets. The non-dispatchable units' emissions are assumed to stay with the Company, as these resources are assumed to be serving our customers at all times. Therefore, DTE Electric's coal, nuclear, and renewable assets, and all PPAs are considered non-dispatchable for the purposes of carbon accounting. Dispatchable units, including all gas units (CCGT and gas peakers) are more likely to be on the margin and able to quickly ramp up and down to supply power to the MISO market.

The generation and the associated emissions from the non-dispatchable units are summed separately. Then, the generation from the Company's non-dispatchable units is subtracted from the DTE Electric customers' load. The difference is what is required to serve our customers' load, beyond the output of the non-dispatchable units. This difference could be positive ("net short") when the Company needs to purchase additional electricity to serve its customers on an annual basis, or this difference could be negative if the Company is a net seller of electricity over the course of the year. A CO_2 intensity (pounds/MWh) corresponding to the U.S. natural gas fleet is applied to this difference. A gas fleet intensity was used as the basis for this carbon intensity calculation because gas units (CCGT and CT) are frequently marginal units supplying the market, meaning they are the next units to dispatch and thus set the market price. Renewables, baseload coal, and nuclear are not typically considered marginal units in the market.

Q90. What is the result of using the net short carbon accounting method to forecast the CO_2 emissions associated with serving the energy needs of DTE Electric's customers?

A90. The result of applying the net short method on the PCA run on the REFRESH scenario is shown in Figure 10.

Figure 10. CO_2 emissions DTE Electric Fleet – net short



As shown in Figure 10, the PCA is forecasted to achieve 65% reduction from 2005 levels in 2029, after the first two Monroe units are retired in 2028. After the second two Monroe units are retired in 2035, the PCA is forecasted to achieve > 90% CO_2 reduction in 2036.

With the addition of the renewables and other technologies in the PCA, the Company is forecasted to be in a net long position with respect to energy production

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over the course of an entire year for the majority of years. In some hours, DTE Electric will buy from MISO, and in some hours will sell according to the MISO dispatching operation. Using the net short method, only the CO_2 emissions associated with our customers' energy usage will be counted. Please refer to Witness Marietta's testimony for details on emissions other than CO_2 and the results of other portfolios run on the BAU scenario.

Q91. What has changed since your last IRP related to the Company's approach to carbon accounting?

A91. The Company's approach to carbon accounting modeling has been improved in two ways. The first was by emission limits being adhered to automatically within EnCompass, setting the emission limit as a constraint. A second enhancement was made to apply carbon accounting on an hourly basis inside the model as part of the hourly fleet dispatch (also known as the hourly net short method) instead of an annual basis as was done in the 2019 IRP. This change adds more precision to the CO_2 accounting by capturing hour to hour changes in the different resources' operation, their interaction with the hourly market, and the associated CO_2 emissions attributable to the customer's supplied hourly energy. Refer to the testimony of Witness Manning for additional details on the EnCompass modeling.

Q92. Is CO_2 accounting currently required in Michigan or MISO?

A92. No. Carbon accounting is not required in Michigan or MISO, nor are specific methods for carbon accounting prescribed. The net short method is a voluntary method that DTE Electric adopted in the 2019 IRP.

Q93. If it is voluntary, then why is the Company applying this methodology?

A93. By using this approach, the Company is able to evaluate the potential impact of carbon emissions from the energy that we provide to our customers, regardless of whether that energy was produced by Company-owned assets or secured through wholesale purchases. The Company is showing an adjustment from fleet direct emissions to estimate the total CO_2 that is attributable to energy that our customers use. DTE Electric believes this is a better representation of the carbon intensity of delivered electricity. As our customers (industrial, commercial, and residential) move in the direction of their own sustainability goals, accounting for net market purchases gives them a more accurate assessment of their full carbon footprint. Because of the changing market dynamics (e.g., plant retirements, increasing amounts of intermittent resources, and changing reliance on markets), this is a more holistic view of potential environmental impact beyond the traditional fleet direct source approach. In the Company's view, this method aligns with the intent of the IRP – to take a more holistic approach to resource planning.

SECTION VII: RISK ASSESSMENT

Q94. Why is risk analysis important in the IRP process?

A94. The PCA should be the most reasonable and prudent plan in the face of an uncertain future, especially given the dynamic nature of the energy industry and emerging technologies. Risk analysis or risk assessment helps to hedge the uncertainties by performing an evaluation of how different portfolios would perform given a range of unexpected possible futures.

All five DTE Electric planning objectives were considered when designing the five risk analysis approaches used in this IRP. Those planning objectives are Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean.

Q95. What are the filing requirements for a utility IRP related to risk analysis?

A95. Commission's December 20, 2017, Order in U-18461, provided Filing Requirements in Exhibit A, which at page four, includes a set of requirements, specifically "Risk Assessment Methodology," which states:

> The utility's IRP filing shall include a thorough risk analysis of the preferred plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the preferred plan and MIRPP plans. The intent of the risk assessment includes a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis 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.

Q96. Which risk analyses did the Company perform?

A96. Five separate risk analyses were conducted:

1. Stochastic economic risk analysis
2. Stochastic reliability analysis (resource adequacy)
3. Evaluation of key inputs
4. Portfolio metric evaluation
5. Scenario and global sensitivity analysis

The MIRPP requirements require that scenarios and sensitivities demonstrate multiple diverse scenarios and sensitivities (the high fuel sensitivity and the high load sensitivity) and are run “globally” across all three MIRPP scenarios (BAU, EP, ET). We performed stochastic analysis in combination with three other methods: 1) application of planning principles, 2) evaluation of key inputs, which are not explicitly listed above in the filing requirements, and 3) scenarios and sensitivities which are discussed in Witness Manning’s testimony.

Q97. Why did the Company choose to perform the types of IRP risk assessments it did?

A97. The Company chose stochastic analysis over other analysis such as generating near-term solutions, mean-variance portfolio analysis, or Monte Carlo simulation because stochastics are considered a best-in-class approach to risk assessment. This is based on a benchmark comparison performed of other utilities’ IRPs, and the Company’s experience with stochastics in its last IRP and Certificate of Necessity case. The Company performed two types of stochastic risk assessment: an economic stochastic risk assessment where affordability is tested and a resource adequacy stochastic risk assessment that tests reliability and resiliency.

Portfolio metric evaluation was chosen to assess key metrics quantitatively across the planning objectives. Evaluation of whether key inputs have changed, and sensitivity and scenario analysis were used to demonstrate the PCA’s reasonable risk under a variety of conditions.

Q98. What is a stochastic analysis?

A98. A stochastic analysis is an advanced modeling technique that uses probability distributions of key drivers to evaluate portfolios. A model simulation is then run multiple times (can be 100's or 1000's) each time using a different set of random numbers selected between the minimum and maximum value of the various probability distributions. Each of these sets of random number selections is called a "draw." This highly quantitative analysis can be applied to test different factors such as economics or reliability under a variety of conditions.

<u>Risk Assessment 1: Economic Stochastic Risk</u>

Q99. Can you describe the economic stochastic risk assessment?

A99. Yes. The economic stochastic risk assessment was performed by Siemens. Additional information can be found in Exhibit A-3.2, appendix L. For each of the portfolios analyzed, Siemens determined the portfolio's average present value as well as its economic risk. The present value is similar to the NPVRR reported from the optimization runs. It represents the portfolio's costs discounted over the study period. The economic risk shows the risk of having a high portfolio cost and was calculated by taking the average of the highest 5% of the draws for each resource plan. In the economic stochastic analysis performed, 200 draws of the key drivers were generated. The goal of the stochastic analysis was to minimize both the average portfolio cost and the economic risk. Key drivers were characterized as probability distribution functions using a combination of historical measures of volatility, market correlations, and the expected future relationships between the assumptions. In Siemens' modeling, the following were evaluated with probability distributions: load growth, natural gas prices, coal prices, the price of carbon used for analytic purposes, the hourly profiles of wind and solar units, and the cost of generating technologies.

Q100. What portfolios did you evaluate in the stochastic risk analysis?

A100. We evaluated nine portfolios, as shown in Table 14 and Figures 11 and 12 below:

Table 14: Portfolios evaluated in the Risk Analysis

Portfolio #	Portfolio Description and Coal Retirements	DSM Capacity added
1	**Preliminary PCA** BR Gas Conversion Monroe 2028, 2035	145 (DR + CVR)
2	**ET least-cost plan** BR 2028 Monroe 2039	77 (DR)
3	**STAKE base plan** BR 2025, 2026 Monroe 2028, 2034	463 (DR + CVR) + 2% EWR
4	**REF 9A phase** BR 2028 Monroe 2032,2035	141 (DR + CVR)
5	**REF least-cost plan** BR Gas Conversion Monroe 2028,2039	112 (DR)
6	**EP least-cost plan** BR 2028 Monroe 2039	0
7	**BAU least-cost plan** BR 2028 Monroe 2039	362 (DR)
8	**REFRESH 6B phase** BR Gas Conversion Monroe 2028,2032	38 (CVR)
9	**Final PCA** BR Gas Conversion Monroe 2028, 2035	38 (CVR)

Figure 11. Cumulative replacement resources by Portfolio 2030

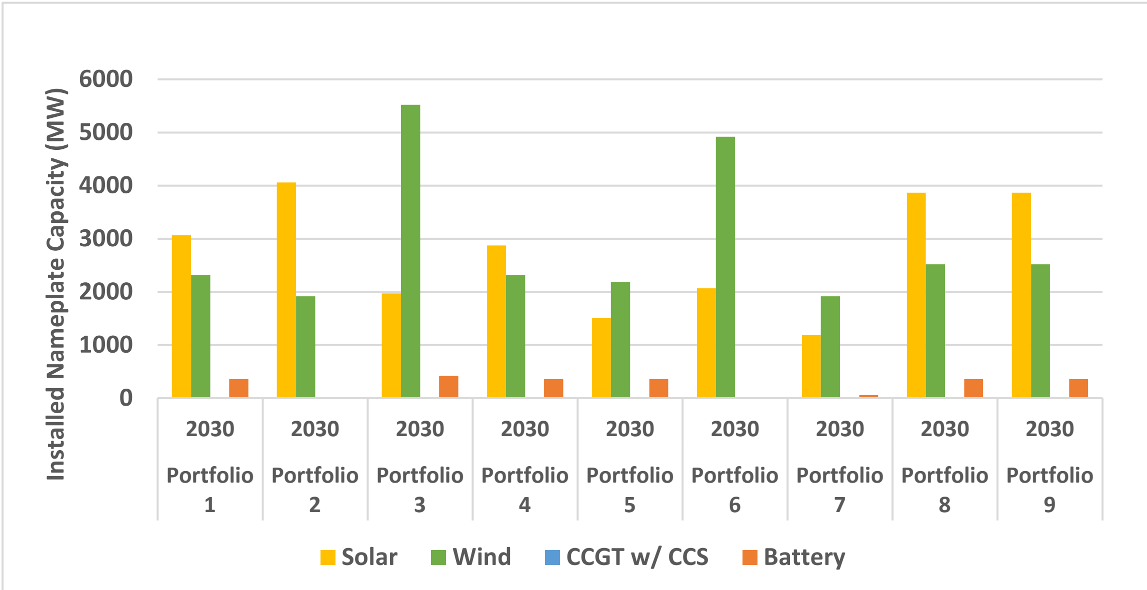
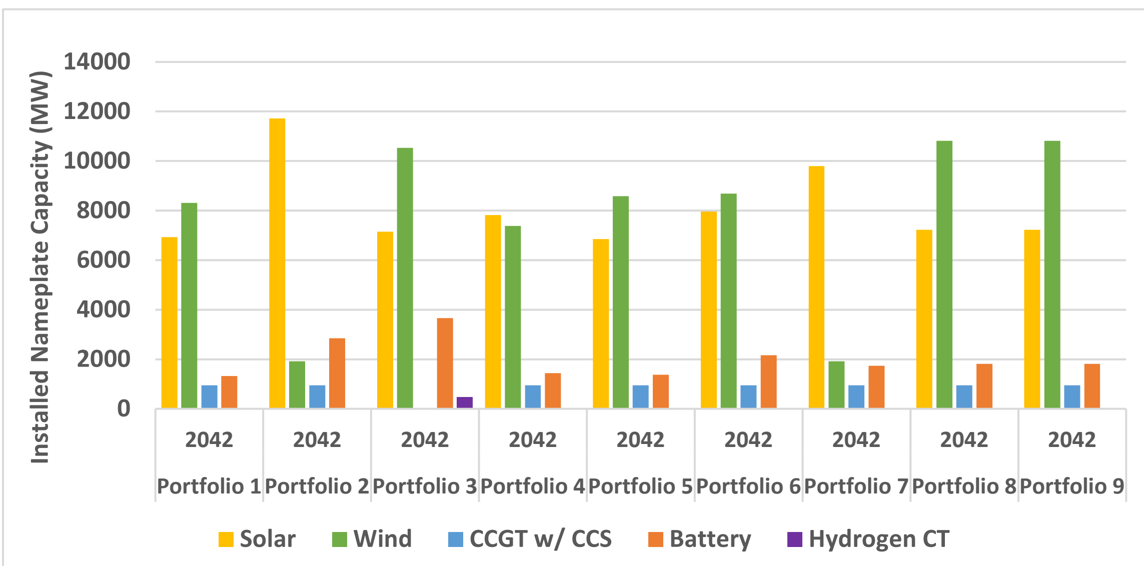


Figure 12. Cumulative Replacement resources by Portfolio 2042



Q101. How did you decide which portfolios to select for the stochastic risk analysis?

A101. The portfolios were selected by examining the EnCompass modeling results under all scenarios and determining which portfolios provided a broad range of futures (different resource selections) to warrant further testing. We selected a representative portfolio from each scenario except the HE. No HE portfolio was selected because a different load forecast was used in the HE scenario, which would make portfolio comparisons invalid due to its different basis. The portfolios met the following criteria:

1. PCA (portfolio 9)
2. Varying retirement dates of Monroe (five different Monroe retirement dates among the nine portfolios)
3. Belle River converted or not converted (four with conversion, five without conversion)
4. Different level of EWR than in the PCA (portfolio 3)
5. Replacement with renewables, storage, and Hydrogen fired CT only (portfolio 3)
6. MIRPP BAU[23], EP, ET, and REF least-cost portfolios (portfolios 2, 5, 6, and 7)

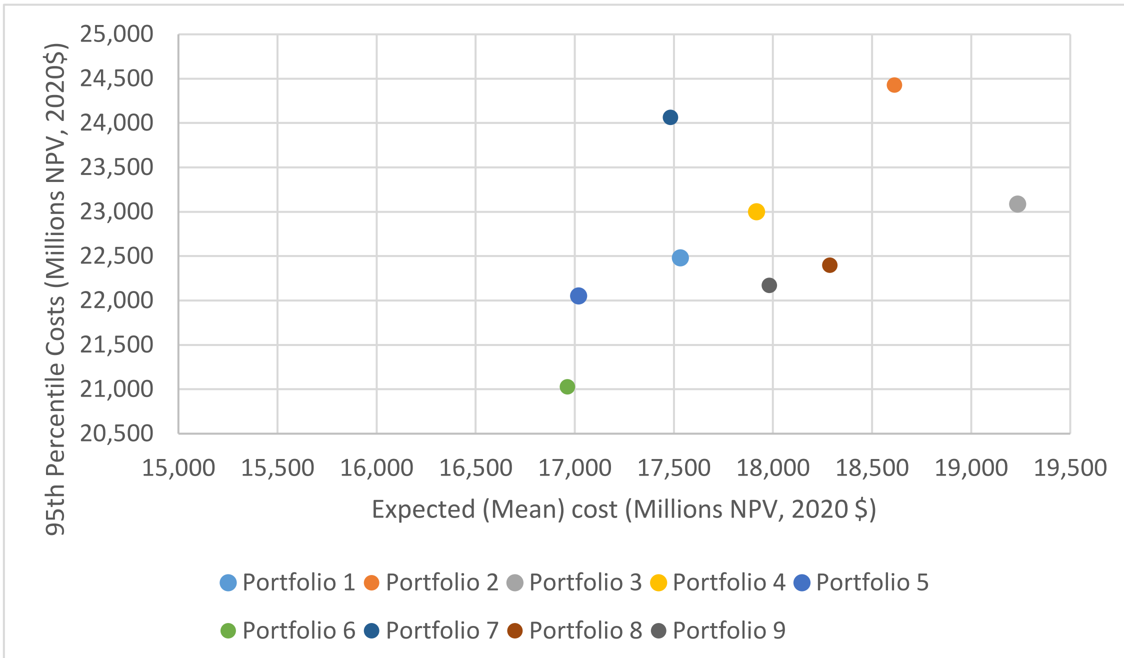
REF 9A Phase (portfolio 4) was selected as an alternative that did not include a Belle River conversion but does have phased in renewables. The Belle River retirement is in 2028 with no gas conversion, hence the first two Monroe retirements are assumed in 2032 to potentially allow enough time for replacement resource build to maintain reliability. The second two Monroe retirements are in 2035, pulled ahead from 2039 for accelerated decarbonization.

[23] The least cost portfolio for the BAU scenario as presented in Table 14 in Witness Manning's testimony was the MIRPP_BAU_CHOICE_15_2024 sensitivity. However, this sensitivity uses a different load forecast, which puts it on a different basis, which would make it incomparable to the other risk portfolios. Therefore, the next least cost plan was chosen. It is the MIRPP_BAU_Base.

Q102. What were the results of the stochastic analysis?

A102. The results are shown in Figures 13 and 14.

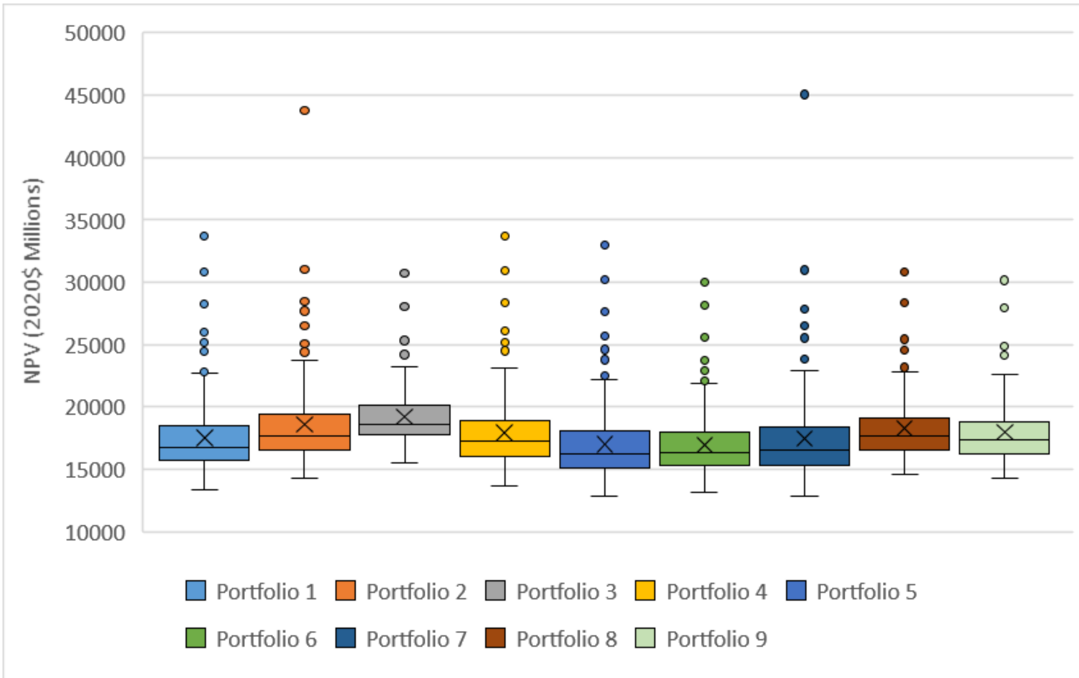
Figure 13. Results of stochastic risk analysis



The goal of determining the expected (mean) portfolio cost and the 95th percentile NPVRR (economic risk) was to select a portfolio that was both the lowest cost and the lowest risk. Portfolio 6, the Environment Policy (EP) least-cost plan has the lowest expected cost and the lowest economic risk and Portfolio 2, the ET least-cost plan, has the second highest expected cost and highest economic risk. Both portfolios have the same retirement schedule. In the ET portfolio, solar and storage is selected as replacement resources. In the EP portfolio, wind is selected along with solar and storage. The PCA is ranked 6th for expected cost and 3rd for 95th percentile (economic risk). The PCA ranks 4th overall.

In addition, the results are presented as box and whisker plots in Figure 14.

Figure 14. **Economic stochastic risk analysis box and whisker plots**



In the box and whisker plots, "X" represents the mean, the horizontal line across the box is the median, the colored box represents the 25th to 75th percentiles, the bottom T shaped projection is the minimum and the top T shaped projection represents the maximum data point within the outlier boundary[24]. The individual data points above the outlier boundary are the outliers. The stochastic results focused on the affordability aspect of risk in a quantitative fashion. The PCA has one of the tightest distributions of results, and it is in the middle of the pack.

Q103. Was an adjustment made to the stochastic analysis results to account for the IRA tax credits?

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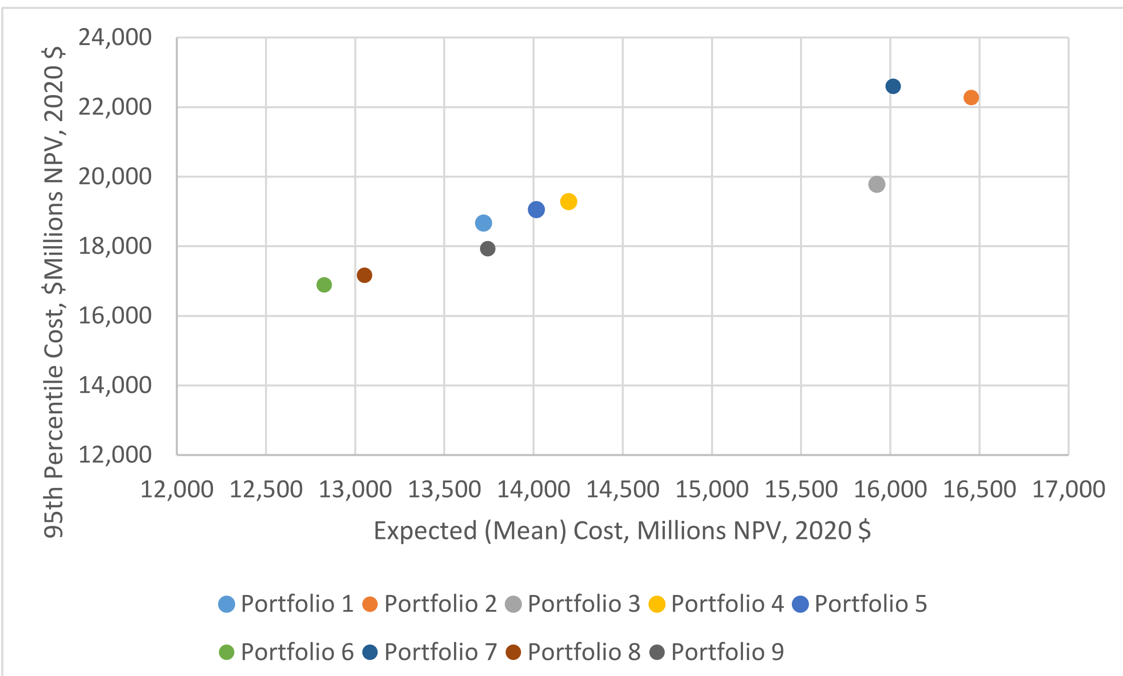
[24] The outlier boundary is determined by taking 150% of the interquartile range, which is the difference between the 25th percentile and the 75th percentile.

A103. Yes, the modeling team was able to apply the IRA tax credits to each of the nine portfolios using the EnCompass model. Witness Cejas Goyanes discusses the details of the IRA tax credits in his testimony. A calculation of delta NPV with and without the IRA tax credits was then determined and applied to the stochastic results. The adjusted stochastic results for the nine portfolios are shown in Figures 15 and 16.

Figure 15. Results of stochastic risk analysis with IRA tax credits applied

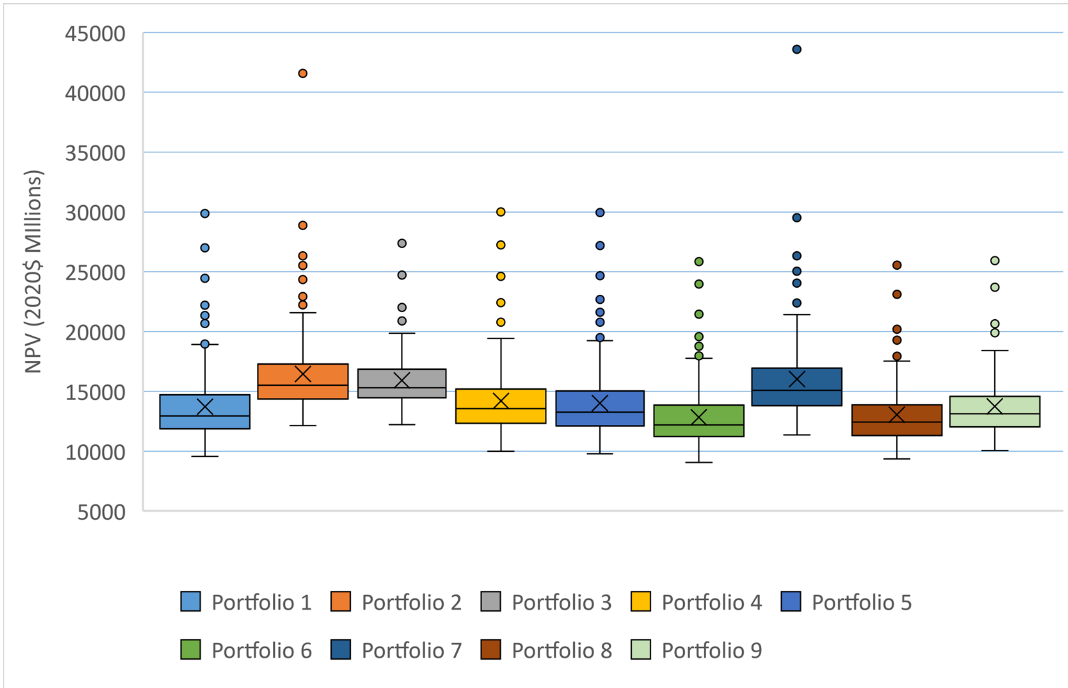


The results indicate that portfolio 6 is still the least-cost. This portfolio is followed by portfolios 8, 9 (Final PCA) and portfolio 1. These results form a relatively straight line. Ranking the portfolios from lower left up to upper right, results in the rankings shown in Table 15.

Table 15: Rank of the portfolios with IRA tax credits applied

Portfolio #	Portfolio name	Rank
1	Preliminary PCA	4
2	ET least-cost plan	9
3	STAKE Base plan	7
4	REF 9A phase	6
5	REF least-cost plan	5
6	EP least-cost plan	1
7	BAU least-cost plan	8
8	REFRESH 6B phase	2
9	Final PCA	3

Figure 16. Economic stochastic risk analysis box and whisker plots with IRA tax credits



Portfolio 6, the EP least-cost plan, performs well in the stochastic risk assessment. It should be noted that this portfolio was completed before the renewables constraints were added to the REFRESH scenario, as discussed by Witness Manning in her testimony. The EP portfolio has 3,000 MW of new wind, added 1,000 MW each in years 2028 to 2030, which is very economic. Therefore, this portfolio is not directly comparable to the PCA, which had a constraint of 200 MW wind maximum applied in years before 2035, but it offers a good data point on what the economics would be without the 200 MW wind constraint. Notwithstanding this stochastic risk assessment focused on economics, there are relevant factors that may affect the viability of this higher level of wind development during this timeframe as discussed in Witness Hernandez's testimony. The least volatile portfolios are 3, 6, 8, and 9, which all have larger amounts of renewables (above

17,000 MW wind and solar as seen in Figure 12), which help to mitigate fuel and market volatility.

Risk Assessment 2: Resource adequacy

Q104. Why is the resource adequacy analysis considered a risk assessment?

A104. The resource adequacy analysis used 6,150 draws to thoroughly test the resource adequacy of the PCA under a variety of weather, load and resource availability combinations of two key portfolio mixes (2028 and 2035 as discussed in section III). It is a form of stochastic risk analysis focused on the reliability planning objective instead of the affordability planning objective as is the case in the other stochastic risk assessment described above. Refer to Section III of my testimony for additional details on the Resource Adequacy modeling.

Q105. Did you consider climate impacts and extreme weather in the reliability stochastic risk assessment (resource adequacy study)?

A105. Yes. We ran an extreme weather scenario on the resource adequacy study. This scenario involved changing the weighting of the 41 weather years to achieve 34 "hot days" per year instead of the historical average of 28 used in the other modeling performed by Astrapé with the resource adequacy model. A hot day is defined as being 86 degrees or above in the DTE Electric service area. The results of this extreme weather scenario were that the LOLE observed on the preliminary 2028 PCA was 0.05 instead of 0.04 (1 day in 20 years instead of 1 day in 25 years). This showed that including the risk of extreme hot weather in the risk assessment increased the amount of UCAP resources needed by 40 MW in 2028 and 43 MW in 2035 to achieve the same reliability as historical weather.

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Risk Assessment 3: Impact of Known Changes

Q106. Can you describe the evaluation of the impact of known changes to the input assumptions used in the IRP?

A106. Yes. The IRP input assumptions were determined between November 2021 and February 2022 before the optimization models were built. Before the filing, in August 2022, we reviewed the inputs to determine if any of them had changed materially since the initial modeling. We also considered the impacts of a few emerging industry trends, such as the IRA tax credits on renewable technologies, batteries, and CCS. (Table 15.12.1 in Exhibit A-3.1 shows inputs considered for changes and whether the change was made.) We based the decision whether to update an input on how materially different the input was, whether the scenarios and sensitivities that had been run could address the identified change, and if there were any known challenges to updating the IRP modeling. After considering 11 different inputs for potential revision, the Company decided that four had changed enough to warrant further consideration. They were:

- Natural gas prices
- Energy markets associated with the updated natural gas prices
- The recently approved IRA tax credits
- The cost estimate for the Belle River conversion

We developed a Refresh scenario (REFRESH) with the updated natural gas prices, electricity market prices based on the updated gas prices, the changes in revenue requirement of alternative technologies impacted by the IRA, and the updated Belle River conversion costs, as discussed by Witness Morren in his testimony. The alternative technologies that were impacted by the IRA tax credits include: wind, solar, storage, SMR, and CCGT w/ CCS. See the testimony of Witness Cejas

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Goyanes for more detail on the tax credit inputs and the testimony of Witness Manning for more detail on the results of the REFRESH scenario and its sensitivities including the update to the Belle River conversion costs.

Q107. Were there any inputs that changed materially that were not updated in the model?

A107. Yes. The recently approved MISO seasonal resource accreditation method, discussed by Witness Burgdorf in his testimony, was considered a material change, however, the needed detail to implement the new capacity accreditations on a seasonal basis is not yet available. Even if the data were available, implementing this change would add complexity and run-time increases to the EnCompass model. To address this update, we performed a capacity position comparison under the portfolio metric evaluation risk assessment.

The Company also considered updating the technology costs based on the latest July 2022 NREL forecast for wind, solar, and storage and the March 2022 EIA forecast, for other resources including gas resources. However, both of these forecasts were issued prior to the IRA legislation in August. The renewables and storage capital equipment markets are likely to change again as a result of the IRA incentives, so the latest NREL and EIA forecasts won't reflect the evolving dynamics of the industry. Therefore, the cost updates to the new resource alternatives focused on the impact of the tax credits to test the preliminary PCA without additional confounding variables.

Q108. Was the preliminary PCA changed as a result of the REFRESH Scenario?

A108. Yes. The IRA tax credits were very impactful to the EnCompass optimization performed on the REFRESH scenario. We found additional amounts of solar, storage, and wind technologies to be more economic with the tax credits applied. The final PCA reflects these additional resources incorporated into the plan as early as feasibly possible to capture the value of the IRA tax credits for our customers.

Risk Assessment 4: Portfolio Metric Evaluation

Q109. What is the portfolio metric evaluation?

A109. The portfolio metric evaluation is a quantitative evaluation of several alternative portfolios that were evaluated for consideration as the PCA, using four different quantitative measures. In our analysis, nine plans were analyzed in the areas of:

1. Capacity position with and without a 500 MW uncertainty band
2. Diversity
3. Economic stochastic box and whisker plots with and without the IRA tax credits
4. Total CO_2 reduction

The nine plans selected for analysis consisted of the same plans evaluated in the economic stochastic risk analysis. The portfolio metric evaluations can each be mapped to four of the five Planning Objectives as shown in Table 16.

Table 16: Portfolio metric evaluation

Portfolio Metric	Planning Objective
Capacity position	Reliable and Resilient, Safe
Diversity	Reliable and Resilient, Safe
Economic Stochastic Risk	Affordable
Total CO_2 reduction	Clean

The planning objective of Customer Accessibility and Community Focus applies to all of the portfolio metrics, because our diverse customer base has differing priorities, which include reliable and resilient, affordable and clean.

Q110. How was the capacity position evaluation performed?

A110. The capacity position evaluation was performed by reviewing each portfolio capacity position in each year and determining how far at or above zero capacity each portfolio was in each year. In addition, there are multiple sources of existing uncertainty that drive the PRMR, which is used to determine the capacity position. These include future thermal accreditation uncertainties detailed in Section III, the recent MISO implemented seasonal capacity construct including a seasonal accreditation, and future changes to the DR accreditation, as discussed by Witness Burgdorf in his testimony. Due to this higher level of uncertainty, a greater long position will reduce the risk of not meeting the PRMR. The Company desires at least 500 MW surplus capacity due to uncertainty from the new MISO seasonal construct and other factors listed above. We selected 500 MW because it is approximately 5% of the PRMR.

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Q111. What are the results of the capacity position evaluation?

A111. The results are shown in Table 17.

Table 17: Capacity Position evaluation

(1)	(2)	(3)	(4)	(5)
Portfolio #	Portfolio name	2023-2042 average above PRMR (UCAP MW)	Number of years 2023-2042 with less than 500 MW UCAP Surplus (Years)	Rank
1	Preliminary PCA	392	13	7
2	ET least-cost plan	1015	7	1
3	STAKE Base plan	167	17	9
4	REF 9A phase	324	14	8
5	REF least-cost plan	465	9	5
6	EP least-cost plan	952	7	1
7	BAU least-cost plan	448	10	6
8	REFRESH 6B phase	751	7	1
9	Final PCA	835	7	1

For each portfolio, the average capacity position above the PRMR is shown in column 3, followed by the number of years that the capacity position is below 500 MW long shown in column 4. The current accreditation method (non-seasonal) was used in the IRP modeling. The lowest risk portfolios therefore have a long capacity position greater than 500 MW UCAP in future years. There are four portfolios that have at least 500 MW of surplus capacity. Those same four portfolios each have seven years that are below 500 MW. Those four portfolios were all given a rank of

1. The remaining portfolios were then ranked in order of closest to 500 MW in decreasing order. Column 5 shows that rank. The four portfolios ranked 1, with an average long position greater than 500 MW are the PCA (portfolio 9), and portfolios 2, 6, and 8.

Q112. What is portfolio diversity and how is it measured?

A112. Diversity is important for an electric generating portfolio to minimize impacts of weather variability, commodity price spikes, and fuel supply interruptions to help ensure grid resiliency. Components of energy resource portfolio diversity that can be quantified include:

1. Variety, or the number of different categories
2. Balance, or how evenly spread are the category populations
3. Disparity, or how different are the different categories from each other

Q113. How was the Diversity Calculation performed?

A113. The Company evaluated three methods of calculating diversity of the nine portfolios: The Shannon-Wiener index, which considers variety and balance, and emphasizes variety over balance; the Simpson Index, which also considers variety and balance, and emphasizes balance over variety; and finally, the Stirling index, which also considers variety and balance, but in addition also considers disparity. The Company chose the Stirling index because of its consideration of three parameters – variety, balance, and disparity. The Stirling Diversity Index is calculated by the equation shown in Figure 17.

Figure 17. Stirling Diversity index

$$\text{Stirling Index Diversity} = \left(\sum_{i,j=1,i\neq j}^{n}\left(d_{ij}p_i p_j\right)\right) * 30$$

Where n is the number of categories (variety), p is the proportion of option i among all options (balance), and d is the disparity between options i and j, first, the energy mix percentage is calculated for each category. The categories considered in the DTE Electric analysis were: coal, gas, nuclear, pumped hydro, oil, solar, wind, and other. Other includes DR, CVR/VVO, EWR, landfill gas and biomass PPAs, PURPA, and contracts under Public Act 2 of 1989 (PA2). Then the product of the energy mix percent for each pair of categories and the disparity score is determined. Finally, products are summed to determine the portfolio diversity by year then multiplied by 30. The disparity scores[25] used are shown in Table 18.

Table 18: Disparity scores

	Coal	NG	Petro	Nuclear	Hydro	Geo	Solar	Wind	Bio	Muni	Other	Battery
Coal	NA	0.17	0.17	0.13	0.27	0.27	0.27	0.27	0.09	0.27	0.14	0.27
NG	0.17	NA	0.06	0.17	0.27	0.27	0.27	0.27	0.17	0.27	0.14	0.27
Petro	0.17	0.06	NA	0.17	0.27	0.27	0.27	0.27	0.17	0.27	0.14	0.27
Nuclear	0.13	0.17	0.17	NA	0.27	0.27	0.27	0.27	0.13	0.27	0.14	0.27

[25] Wu, Tiffany, and Varun Rai. "Quantifying Diversity of Electricity Generation in the U.S.", 7. The University of Texas at Austin Energy Institute, July, 2017. https://energy.utexas.edu/sites/default/files/UTAustin_FCe_Quantifying_Diversity_2018_Feb.pdf.

Hydro	0.27	0.27	0.27	0.27	NA	0.20	0.20	0.08	0.27	0.13	0.14	0.27
Geothermal	0.27	0.27	0.27	0.27	0.20	NA	0.12	0.20	0.27	0.20	0.14	0.27
Solar/PV	0.27	0.27	0.27	0.27	0.20	0.12	NA	0.20	0.27	0.20	0.14	0.27
Wind	0.27	0.27	0.27	0.27	0.08	0.20	0.20	NA	0.27	0.13	0.14	0.27
Biomass	0.09	0.17	0.17	0.13	0.27	0.27	0.27	0.27	NA	0.27	0.14	0.27
Muni/Ind Waste	0.27	0.27	0.27	0.27	0.13	0.20	0.20	0.13	0.27	NA	0.14	0.27
Other	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	NA	0.27
Battery	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	NA

Q114. What were the results of the diversity comparison across the nine portfolios?

A114. The results are shown in Table 19.

Table 19: Diversity Comparison

Portfolio #	Portfolio name	Stirling diversity index average 2023-2042	Rank
1	Preliminary PCA	2.448	3
2	ET least-cost plan	2.427	7
3	STAKE Base plan	2.341	9
4	REF 9A phase	2.433	5
5	REF least-cost plan	2.429	6
6	EP least-cost plan	2.449	2
7	BAU least-cost plan	2.347	8
8	REFRESH 6B phase	2.440	4
9	Final PCA	2.451	1

The top seven portfolios are tightly grouped between 2.427 and 2.451 scores, the higher score being more diverse. The PCA has the highest score indicating the highest diversity of the nine portfolios.

Q115. What is the Comparison of CO_2 tons emitted across the various plans?

A115. The total forecasted amount of CO_2 in the study period of 2023-2042 is compiled below in Table 20 for the nine portfolios. CO_2 tons is presented in both total fleet tons forecasted and total tons on a net short basis. The scenarios that the portfolios were run on are listed under Portfolio.

Table 20: CO_2 Comparison

Portfolio	CO_2 Tons fleet (Million tons)	CO_2 tons net short (Million tons)	Reduction from highest portfolio (net short)	Rank (net short)
Portfolio 1: preliminary PCA (REF)	238	245	37%	4
Portfolio 2: ET least-cost plan	375	360	7%	8
Portfolio 3: STAKE Base	264	226	42%	2
Portfolio 4: REF 9A phase	268	271	30%	5
Portfolio 5: REF least-cost plan	254	270	30%	5
Portfolio 6: EP least-cost plan	362	321	17%	7
Portfolio 7: BAU least-cost plan	387	388	highest	9
Portfolio 8: REFRESH 6B phase	214	211	46%	1
Portfolio 9: Final PCA (REFRESH)	231	230	41%	3

The comparison of forecasted CO_2 tons shows that the Monroe retirement date plays the biggest role in reducing the amount of CO_2 released. The portfolios with the Base retirements of Belle River in 2028 and Monroe in 2039 (ET, EP, and BAU) all have the highest CO_2 tons. The lowest CO_2 tons is in portfolio 8 with two Monroe units retiring in 2028 and the second two units retiring in 2032. The STAKE base portfolio with staggered Monroe retirement dates of 2028 and 2034 is followed closely by the PCA with two units at Monroe retiring in 2028 and the second two in 2035 for the second and third least CO_2 emissions.

Q116. What are the conclusions of the portfolio metric evaluation?

A116. A summary of results is shown in Table 21. The rankings for each of the four evaluations are shown with 1 being the best and 9 being the worst.

Table 21: Portfolio Metric evaluation summary

Portfolio	Capacity position	Diversity	Stochastic risk with tax credits	CO_2 tons reduced
Portfolio 1: Prelim PCA	7	3	4	4
Portfolio 2: ET least-cost plan	1	7	9	8
Portfolio 3: STAKE Base	9	9	7	2
Portfolio 4: REF 9A phase	8	5	6	5
Portfolio 5: REF least cost plan	5	6	5	5
Portfolio 6: EP least cost plan	1	2	1	7
Portfolio 7: BAU least cost plan	6	8	8	9

Portfolio 8: REFRESH 6B phase	1	4	2	1
Portfolio 9: Final PCA	1	1	3	3

The PCA (portfolio 9) ranks high across all of the portfolio metrics. This means that it is a robust portfolio: reliable in terms of capacity position, diverse, low cost in an uncertain future with low economic risk and is in the top third in terms of CO_2 tons reduction. The other strong portfolio is portfolio 8, a portfolio based on the least-cost plan optimized on the REFRESH scenario. Portfolio 8 includes Monroe unit retirements in 2028 and 2032. While a 2032 Monroe retirement is desirable in terms of reducing CO_2 faster and the least-cost REFRESH portfolio, when compared to the PCA, it has much greater execution risk in terms of the timelines to build the large amounts of replacement resources, including renewables and the CCGT with CCS, as well as necessary grid upgrades. With respect to generation development, transmission upgrades, and the recent and ongoing difficulties we have seen across the industry with siting and interconnection, as discussed by Witnesses Roy and Hernandez in their testimonies, it is unrealistic to presume that all the required builds will be timely and there will be no siting or interconnection delays. Portfolio 8's retirement schedule for Monroe assumes no such delays. The PCA takes a more measured approach in terms of build of replacement resources to maintain reliability and required grid upgrades. The PCA balances decarbonization with affordability and maintains higher reliability by keeping approximately 1,500 MW of firm dispatchable resources on the system for three extra years, allowing time to fully work through the complex interconnection processes and new resource bid, design, build, and start up processes as well as allowing additional time for emerging technology advancement. These three years

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could be significant in terms of the commercialization of emerging technologies, whether that is CCS or other alternatives for low-emission, dispatchable generation. For example, the DOE Hydrogen Shot seeks to "reduce the cost of clean hydrogen by 80% to $1 per 1 kilogram in 1 decade."[26] I presume this to mean that by approximately 2030, the R&D, pilots, demonstration projects, scale up, and commercialization for a hydrogen generation project are expected to be complete. If successful, utilities at that point could start proposing utility scale hydrogen generation/firm dispatchable electricity generation technology projects in their IRPs in the 2030 timeframe; which if approved would take multiple years to engineer and construct. This brings the potential timing of a promising firm dispatchable zero carbon resource closer to 2035 than 2032.

Q117. What do the results of the risk analysis say about the proposed IRP plan?

A117. The five types of risk assessment that we performed support that the PCA is economic under a variety of situations, is robust and prudent, and is extremely flexible to incorporate emerging technologies. The PCA was ranked 4th in the initial economic stochastic analysis and 3rd in the economic stochastic analysis with the IRA tax credits included. The PCA also meets the desired resource adequacy target as discussed in Section III. The portfolio metric evaluation showed excellent to moderate performance of the PCA across all four metrics (diversity, capacity position, economic stochastic risk, and CO_2 emissions). Given the pace of change in the energy industry and market conditions, the Company completed an assessment of the data assumptions used in the IRP starting point against current

[26] Hydrogen Shot | Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-shot, accessed October 19, 2022.

information. This resulted in the development of the REFRESH scenario, which incorporated the results of the IRA tax credits, passed in August 2022, into the IRP capacity expansion optimization. The Company updated the PCA as a result of this REFRESH scenario. The final PCA is more affordable (see section VIII and Witness Manning's testimony), more reliable (see section III, Table 6), and decarbonizes faster than the preliminary PCA (see Table 20 earlier in this section). Finally, the PCA was considered across multiple diverse futures with the scenario analysis discussed by Witness Manning in her testimony (see Table 18 in Witness Manning's testimony).

SECTION VIII: OVERVIEW OF THE RESULTS OF THE IRP ANALYSIS AND SYNTHESIS OF RESULTS INTO THE PCA

Q118. Can you describe the process of synthesizing the results into the PCA?

A118. Yes. We considered the Company's planning objectives along with the many modeling results and other considerations including stakeholder feedback, economics, electric reliability, environmental impacts, industry trends, and details on the alternative resources. I will review all these factors in turn and describe the how we balanced them together to determine the PCA.

Q119. How were the planning objectives considered in the development of the PCA?

A119. The Company used the planning objectives as guidance in the determination of the PCA as explained below.

Reliability from the Reliable and Resilient planning objective is an important IRP requirement. Each plan analyzed was required to meet the reliability planning requirements established by MISO (these requirements are described in more detail by Witness Burgdorf in his testimony). Additionally, we explicitly modeled resource adequacy, or the ability of the plan to serve load every hour of every day. When selecting a plan, the Company looked at the potential reliability impact of hours when energy supply is less than energy demand (potential loss of load hours). As renewable penetration increases in MISO LRZ 7, the Company expects the effects on grid reliability (new stability risk and shifting periods of grid stress)[27] will increase over time. MISO has acknowledged increased power plant retirements[28] and other changes with the shift to increased renewable energy across its footprint, issuing its Renewable Integration Impact Assessment (RIIA) that "demonstrates that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks."[29] Furthermore, MISO has stated, "As the net-load peak shifts, driven by an increasing amount of installed renewable capacity, the value of the capacity, measured by the average Effective Load Carrying Capability metric, declines."[30] Witness Roy discusses the MISO RIIA study in more detail in his testimony. ELCC is further described in my testimony in section III and by Witness Carden from Astrapé Consulting in his testimony.

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[27] "MISO's Renewable Integration Impact Assessment (RIIA)", 3. MISO, February, 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, accessed October 19, 2022.
[28] MISO, 2022 Regional Resource Assessment, Presentation to the Resource Adequacy Subcommittee, August 24, 2022, available at https://cdn.misoenergy.org/20220824%20RASC%20Item%2006%20Regional%20Resource%20Assessment%20Presentation626035.pdf, accessed October 19, 2022.
[29] MISO. "MISO's Renewable Integration Impact Assessment (RIIA)", 2. MISO, February, 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, accessed October 19, 2022.
[30] MISO. "MISO's Renewable Integration Impact Assessment (RIIA)", 26. MISO, February, 2021. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, accessed October 19, 2022.

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Resiliency was considered by the Company by ensuring that we have a diverse portfolio of resources. Portfolio diversity is discussed in section VII of my testimony. The Company desires a portfolio that minimizes energy-market risk by having enough owned or contracted generation at the right times, and by not being overly reliant on one particular type of generation resource or the potentially volatile and uncertain energy and capacity markets. We also considered resiliency by ensuring that the PCA reduces fuel supply risk by planning for firm gas deliverability from multiple sources as discussed by Witness Pratt in his testimony. In addition, the Company considered the staging of new resources to be prepared for the phased retirements of existing coal generation and the overall supply adequacy conditions in LRZ 7, including the impact of expected new generation and retirements outside the Company's footprint. The Company took a holistic approach to resource adequacy and grid reliability modeling to prudently plan for its customers while recognizing the broader changes taking place in the energy industry.

Affordability was considered in part with the economic selection of the resource portfolios as described above. Affordability was also measured by the yearly impacts to the revenue requirement. While a potential resource plan may be economic by the end of the approximately 20-year study period, that economic value may not be realized until the distant future; the Company also considered near-term customer impacts. We also considered impacts to customer rates, including limiting exposure to commodity and energy price volatility.

The IRP planning objective **<u>Clean</u>** refers to environmental sustainability and the Company's clean energy and carbon reduction goals as discussed by Witness Leslie in her testimony, as well as State and Federal carbon reduction goals, which we considered in the determination of the PCA. The team designed each portfolio to meet all current environmental regulations. The Company considered the emissions generated to supply its customers, including those in power purchased for resale from the hourly MISO spot market and PPAs, in the quantification of CO_2 emissions of each portfolio under consideration, using carbon accounting as detailed in Section VI. In this IRP, the Company also completed an EJ screening and analysis of the portfolios' potential impacts to vulnerable communities (referred to as an EJ assessment). Refer to Witness Marietta's testimony for additional details on the EJ assessment.

The next planning objective the Company considered in the IRP process was **<u>Customer accessibility and community focus</u>**. The Company desires a plan that increases the adoption of renewables and storage resources and continues demand-side management programs that support access to clean energy and energy management programs for customers. As Witness Leslie describes in her testimony, participants in the Voice of the Customer research expressed a desire for a diverse and balanced mix of energy sources, with renewable energy leading the way and natural gas playing a role to support reliability. The Company assumes these new resources will be developed in Michigan, driving investments in the state to support local businesses and grow clean energy jobs. We also considered the impact on local communities with existing power plants in developing the PCA. As discussed by Witness Marietta in his testimony, the EJ analysis evaluates the environmental and health impacts of certain portfolios thereby informing the development of the PCA by providing a comparative view of the potential environmental and public health impacts on certain communities under various alternatives studied. In addition, Company representatives initiated outreach to Belle River and Monroe power plant community representatives in advance of the IRP to collaborate on socioeconomic impact studies given potential changes that may occur due to various scenarios being assessed in the IRP.

The last planning objective the Company considered in determining the recommended plan was **<u>Safe</u>**. Safe was considered in the selection of the PCA in several ways. This included ensuring that ongoing resource O&M budgets are adequate to support safety related maintenance for the entire study period, selecting a plan that reduces the risk of impacts to customers related to power outages from loss of load events, and ensuring that the capital cost estimates of new resources included the options for needed safety related equipment.

Q120. What factors other than the planning principles did the Company consider when analyzing the IRP modeling results in the development of the PCA?

A120. The Company considered several factors when analyzing the modeling results in the development of the PCA. These include stakeholder feedback, economics, reliability, environmental impacts, industry trends, and resources. These are detailed below.

Line No.

Stakeholder Feedback

Q121. How was stakeholder and customer feedback considered when developing the PCA?

A121. As discussed by Witness Leslie in her testimony, the Company conducted a robust stakeholder engagement process. Several key themes that resulted from stakeholder engagement included:

- Customers' perspectives relative to the generation transition, including the expectation to continue to adopt wind and solar technologies and diversify DTE Electric's energy mix while staying reliable and affordable.
- Interest in the Company progressing its decarbonization goals and accelerating the retirement of the Company's coal-fired power plants.
- Interest in further adoption of renewables, storage and EWR in the generation plan.

When developing the PCA, the Company considered these to ensure the plan was meeting the general themes shared by customers and stakeholders. More detail on stakeholder outreach is provided in Exhibit A-1.4, DTE Electric Stakeholder Report

Economics

Q122. How were the economic results of the IRP modeling used to develop the PCA?

A122. We examined the NPVRR results as well as the associated coal-fired power plant retirement dates and the selected resources for the various portfolios and identified the least-cost portfolios across the scenarios. Refer to Witness Manning for additional detail on the modeling results. In the BAU, EP, and ET scenarios, the base retirement schedule of 2039 for all four Monroe units was the least-cost. In the REF scenario, the phased 2028 (Units 3 and 4) and 2039 (Units 1 and 2) retirement schedule was least-cost. In the REFRESH scenario a two-unit retirement in 2028 with the second two units in 2032 was least-cost (accelerating the retirement of the second two Monroe units to capture the anticipated CCS IRA credit earlier). In addition, when a staggered Monroe retirement was paired with the Belle River natural gas conversion, the resulting NPVRR proved even more economic.[31] The natural gas conversion of Belle River, as a dispatchable resource, is economic to replace the early retirements of Belle River on coal in 2025-2026 and Monroe Units 3 and 4 by the end of 2028. Based on this, the Company identified that staggering the retirement of Monroe and pairing that with a Belle River conversion should be incorporated in the PCA. The PCA saves over $500 Million NPV over the Base plan (starting point) with the 2028 Belle River and 2039 Monroe retirements.[32]

Q123. Were impacts from the IRA that was signed into law August 16, 2022 incorporated into the PCA?

A123. Yes. The IRP team added a REFRESH scenario, described in Section VII of my testimony, that applied the tax credits in the EnCompass model. The tax credits are detailed by Witness Cejas Goyanes in his testimony. The results of this EnCompass optimization showed that the IRA tax credits provided significant value. We updated the preliminary PCA after we ran the REFRESH scenario to take advantage of the tax credits with renewables and storage being added earlier in the study

[31] Refer to the testimony of Witness Manning, Table 3: When case 8B is compared to case 8A, there is a $202 M NPV benefit for case 8B with the BR conversion, similarly comparing cases 7B vs. 7A show a $245 M NPV benefit for case 7B with the BR conversion. See also Table 16 in the testimony of Witness Manning for similar results on the REFRESH scenario: 7B is $85 M NPV less than 7A.

[32] Refer to the testimony of Witness Manning, Table 18. The REFRESH 2022 PCA FINAL is $539 M NPV less than the REFRESH_BASE.

period as compared to the preliminary PCA. As Witness Manning describes in her testimony, the final PCA is $429 million[33] NPV less costly than the Preliminary PCA.

Q124. Were any other insights gained when looking at the IRP modeling results related to economics?

A124. Yes. The EnCompass model run results show the optimal portfolio in terms of economics based on the inputs and assumptions. This includes building new resources in the year that is least-cost. In many cases, this is the last possible year before or when the resource is needed to replace a plant retirement. In other cases, like the REFRESH scenario with the tax credits, it is economic to build earlier to capture value. Even though last minute replacement or immediate build is the lowest cost way to complete the builds, it is not feasible, practical, or even desirable to build resources all in one year for many reasons, several of which are described below.

1. There could be delays in the timing of new resources or the required interconnections;
2. Having extra capacity available may reduce the LOLE for LRZ 7 (i.e., improve resource adequacy). From a pure economic sense, ideally new generation would come online at the exact same time as other generation is retired, however, this poses a risk to reliability as there is no longer the large "excess generation" (generation in excess of requirements) available across MISO; moreover, uncertainty in load forecasts due to

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[33] Refer to the testimony of Witness Manning, Table 16: The difference between sensitivity REFRESH_2022_PRELIMINARY_PCA and REFRESH_2022_PRELIMINARY_PCA_OPT.

electrification, weather, and economic conditions as well as changes to capacity accreditation protocols reinforce the value of maintaining adequate capacity reserves through this dynamic time in the industry;

3. It provides the operators of the new resources time to adjust and address any operational issues;
4. It could help mitigate supply chain constraints or other market factors that affect the competitiveness of new resource prices; and
5. It is more manageable from a workflow perspective to phase modular projects in over a number of years than build them all in one year.

For those reasons, while we used the EnCompass results to inform the optimal retirement schedules of Monroe and Belle River Power Plants in the PCA, we did not necessarily use the exact years of the economically optimal replacements. Instead, we phased in some of the replacement builds when considering possible PCA plans. Phasing in these resources mitigates the issues addressed above, however it could increase the revenue requirement compared to building new resources in the year economically selected by the model. This increased cost is a nominal cost to reduce execution risk and ensure reliability if the replacement resources are not in place prior to the plant retirements.

<u>Electric Reliability</u>

Q125. How was reliability considered when reviewing the results of the IRP modeling and development of the PCA?

A125. The timing of retirements and resource additions is critically important to ensure there is sufficient time to allow for advance planning, especially given the size of

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the Monroe Power Plant. Monroe is one of the largest power plants in the country and provides benefits to both LRZ 7 and the broader MISO region. The converted Belle River units, which maintain their full capacity, in addition to the solar and storage identified, will be key resources supporting electric reliability by facilitating the retirement of the first two units at Monroe Power Plant. Due to the economic approach to resource selection in EnCompass described in the previous questions and industry factors described later in my testimony, the Company deemed it prudent to phase in 800 MW of solar and 240 MW of storage resources to ensure they were operational and in-service prior to the retirement of the first two units of Monroe.

The retirement of the last two Monroe units (1,500 MW) presents additional complexity to maintain resource adequacy and will require substantial transmission upgrades as discussed previously in my testimony and by Witness Roy in his testimony. Our customers deserve a seamless transition on the grid when Monroe retires, and the Company, in partnership with ITC and MISO, is responsible for managing and planning that transition safely, reliably and cost effectively. To do this, thoughtful due diligence is required in the areas of resource adequacy and transmission modeling and planning. Thus, we included a placeholder low or zero carbon dispatchable unit (CCGT with CCS) coincident with the second two Monroe units' retirement in almost all modeling runs. Refer to Witness Manning for additional details on the scenarios and sensitivities.

Selecting a conversion of Belle River to gas with a staggered retirement of Monroe complements the large renewable build expected over the study period by being available 24/7 when customers may need it. It also allows reasonable time for installation of new resources as well as emerging technology to develop prior to the second two Monroe unit retirements. The phased approach also allows upgrades on the grid systems to be identified and addressed and in future IRPs to fully consider and analyze the best replacement of 1,500 MW coal baseload units when Monroe fully retires. Resource adequacy is further discussed in Section III.

Environmental Impacts

Q126. How were the emissions results of the IRP modeling used to develop the PCA?

A126. We started with our current emissions goals as our baseline. The baseline included retirement dates of 2028 for Belle River and 2039 for Monroe, and 50% and 80% CO_2 interim reduction goals respectively. The Company modeled alternative retirement dates for its coal-fired power plants. Accelerating the retirements dates could further advance the Company's CO_2 emissions reductions over the study period resulting in the opportunity to update the Company's interim CO_2 reduction goals supporting its decarbonization journey. After considering economics and reliability, the IRP team looked at the emissions outputs from the portfolios that included a Belle River conversion and staggered Monroe retirement dates as well as various renewable and storage additions. The EnCompass modeling results confirmed that the CO_2 reductions were accelerated from the current goals of 50% in 2028 and 80% by 2040 in these portfolios along with several other significant emissions reductions.

In addition to accelerating the Company's CO_2 emissions goals, it was important to ensure that the Company's CO_2 reductions supported the state and federal GHG goals, which are described by Witness Leslie in her testimony. The Company did confirm that the PCA would support the GHG emissions reduction goals defined in both the MI Healthy Climate Plan[34] (MIHCP), as well as by the Biden Administration.[35] See Table 22, below.

Table 22: DTE Electric CO_2 reduction compared to State/Federal Goals

	2025	2030	2050
MIHCP goals (economy-wide, from 2005)	28%	52%	Carbon neutrality
Federal goals (economy-wide, from 2005)		52%	Net zero
DTE Electric (from 2005)	32% (projected by 2023)	65% (projected in 2028)	

In addition, the Company ran a scenario (STAKE), which follows parameters defined in the draft MIHCP and which is detailed in Witness Manning's testimony. This scenario included early retirement of both Belle River (2025/2026) and Monroe (2028/2035) and a 50% renewable portfolio standard by 2030 among other assumptions.[36] The modeling runs resulted in portfolios that included high levels of renewable builds, lowering CO_2 emissions quickly. See Figures 11, 12 and Table 20. However, unlike the PCA, which includes the proposed Belle River conversion, this portfolio does not include a dispatchable resource in 2028 tied to the first two

[34] MI Healthy Climate Plan available at https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed October 17, 2022.
[35] White House National Climate Task Force: https://www.whitehouse.gov/climate/#:~:text=Reducing%20U.S.%20greenhouse%20gas%20emissions,clean%20energy%20to%20disadvantaged%20communities, accessed October 17, 2022.

[36] See Witness Manning's testimony for additional sensitivities including alternative retirement dates:

units retiring at Monroe. Demand response, wind, solar, and storage are the replacement resources selected to replace Monroe's capacity, which replace the first two units at Monroe and the full Belle River retirement, as shown in Table 23. The capacity position is reduced to 0 MW long in 2029, following the Monroe 2-unit retirement. This portfolio ranks last on the capacity position metric evaluation (see Table 17). A capacity position this tight is considered high risk in terms of reliability with increased potential to have loss of load (see section VII). While the STAKE portfolio is forecasted to decarbonize slightly quicker than the PCA by a total of four Million tons over the 20 year study period as shown in Table 20, the added reliability risk in the late 2020s is not a desired outcome or an acceptable tradeoff for increased decarbonization.

Table 23: STAKE Base results

STAKE Base	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
MW Additions											
Solar				*496*			*400*				*700*
Wind					*1000*	*1000*	*600*	*1000*	*1000*	*1000*	*300*
Storage							*420*				
Demand Response			*1*	*26*	*74*	*117*	*204*	*16*			
CVR/VVO							8				8

Q127. How were Environmental Justice (EJ) screening results considered in the PCA?

A127. The environmental justice analysis looks at both emissions projections as well as an EJ screening and analysis using the EPA Environmental Justice Screening and Mapping Tool (EJSCREEN) tool. All fossil fuel-fired generating facilities were included in the screening. The goal of the screening was to identify vulnerable communities located within a 3-mile radius of each facility. As discussed by Witness Marietta in his testimony, although Belle River and Monroe are not located in areas identified as vulnerable by the EJSCREEN tool, the accelerated retirements cause a reduction in associated emissions, water impacts, and waste generation, which has a positive outcome and reduces the overall impact in the area. In addition to the CO_2 emissions reductions stated above, the PCA drives additional emissions reductions including nearly a 100% reduction in sulfur dioxide and mercury, 92% reduction in carbon monoxide, 95% reduction in nitrogen oxides, greater than 70% reduction in particulate matter, and 66% reduction in volatile organic compounds by 2042.

There are several peakers identified in the EJSCREEN tool located in vulnerable communities that are being evaluated for potential retirements. Peakers are discussed in more detail below.

Industry Trends

Q128. How were the current renewables market trends considered in the PCA?

A128. Company experience has shown that delays in the MISO interconnection queue, recent RFP results, supply chain and labor market constraints, and local opposition can limit the amount of renewable energy that can be built at any given time. To help mitigate this execution risk of installing renewable resources according to a specific timeline, the Company desired flexibility in the PCA with respect to installation dates on the renewables. The Company deemed it was prudent to phase in renewable installations in a measured approach starting earlier in the time period

(2026) to prepare for the retirement of the first two units of Monroe rather than installing all renewables in the year deemed to be most economic by the EnCompass model. This action to phase in the renewable builds allows time to mitigate some of the challenges the industry has been facing as described in more detail by Witness Hernandez in her testimony.

Resources

Q129. How were battery storage resources considered in the PCA?

A129. The IRP team included battery flexibility benefits and optimistic battery prices in the ET scenario. While the battery prices are somewhat uncertain in this high inflationary time, inclusion of the battery benefits into the EnCompass optimization showed that the batteries were economic in the ET scenario. Batteries were weighted heavier when deciding to include 240 MW of batteries in the PCA phased in between 2025 and 2028. In addition, in the REFRESH scenario, with the IRA tax credits, batteries have more value. The Company desires to gain experience with batteries in the near term to capture synergies with the added intermittent renewable resources and help replace the dispatchable capacity lost with the retirement of the first 1,500 MW at Monroe.

Q130. How was CVR/VVO considered in the PCA?

A130. The Company implemented a CVR/VVO pilot, as discussed by Witness Musonera in her testimony. As the Company scales up CVR/VVO beyond the pilot it will evaluate CVR/VVO as an offset to peak generation, and the potential benefits provided to the distribution grid. It was economically selected in a few runs that have higher load forecasts.[37] Therefore, the PCA includes a nominal amount of CVR/VVO deployed in the years 2026 to 2030.

Q131. How was EWR considered in the PCA?

A131. In the IRP modeling, different levels of EWR programs were available to the EnCompass model for economic selection. In the vast majority of portfolios, the model economically selected the EWR level determined by the Statewide Potential Study. Therefore, the EWR Statewide Potential Study level was selected in the PCA.

Q132. How was DR considered in the PCA?

A132. Although the preliminary PCA had 125 MW of DR in 2040, the final PCA does not include any additional DR, as the model did not economically select it over the renewables and storage with lower costs benefiting from the IRA tax credits. The Company expects, by the 2026-2027 planning year, demand response to be 949 MW, which is 9% of the Company's PRMR. We would like to complete the already-planned expansion of the current programs to ensure that their expected UCAP capacity is available as well as to ensure that the legacy DR programs are maintaining their expected UCAP. In addition, there is uncertainty with future MISO accreditation of demand response programs, as discussed by Witness Farrell in his testimony. These factors make further expansion of DR programs not as desirable as some other resources.

[37] MIRPP High Load sensitivity is in NDA WP SDM 48-MIRPP_BAU_High_Load

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Q133. How were the peakers that were identified for potential retirement considered in the PCA?

A133. The Company undertook a peaker analysis as described by Witness Morren in his testimony. That analysis identified three peaker sites for potential future retirement. Witness Morren describes the Company's plans to continue the peaker analysis including retain or retire strategies in the future. In her testimony, Witness Musonera describes the importance and complexity of the distribution system analyses in this study process due to the role of peakers in supporting distribution system reliability. Several peakers are being evaluated by MISO for potential future retirement but the Company did not include them in the PCA since the evaluation is on-going at the time of this filing. Additional analyses by the Company of the peaking generation and replacement options will inform a more comprehensive strategy going forward.

Results

Q134. After the above factors were considered, did you identify a preliminary PCA?

A134. Yes. Incorporating the above considerations, we identified the optimized, least-cost plan from the EnCompass modeling runs with staggered 2028 and 2035 Monroe retirements that included the Belle River Power Plant conversion as the preferred retirement sensitivity to design the preliminary PCA around. This was the "7B" sensitivity. The optimized 7B portfolio also contained the proxy CCGT w/CCS, solar, wind, and storage by 2035, as seen in Table 24. Then, we phased in the solar, battery, and wind resources as discussed above. This approach also aligned with stakeholder feedback and the earlier renewables resources that were selected in the STAKE scenario. The Company also added the CVR/VVO program to continue to take advantage of waste reduction opportunities on the distribution system. The specific adjustments made to the Case 7B were:

1. 1580 MW of Solar from 2031 to 2034 was phased in between 2026 to 2030;
2. Approximately 150 MW of Wind from 2035 was phased in between 2028 and 2029;
3. Battery was phased in from 2025 through 2028, instead of installing it all in one year (2028);
4. The CVR/VVO program was added in years 2026 through 2030;

After these adjustments were made, the model was rerun on the REF scenario to optimize the plan. Table 24 depicts the results of 7B before and after the rerun. The bottom table is the resulting Preliminary PCA through 2035. The optimization eliminated the DR program that had previously been selected in 2028.

In Table 24, bold font indicates movement (wind, solar, battery) or addition (CVR/VVO) of resources.

Table 24: Evolution of the Preliminary PCA

REF_ CASE_7B	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
MW Additions													
Solar						*420*	*2*		***1000***	***1000***	***1000***	***1000***	
Wind								*254*					***1000***
Storage						***360***							
Belle River Conversion			*517*	*517*									
Proxy CCGT w/CCS													*946*
Demand Response						*123*							
CVR/VVO													
REF_ Prelim PCA	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
MW Additions													
Solar				***400***	***400***	***400***	***400***	***400***		*1000*	*1000*	*541*	
Wind						***100***	***100***	***200***					*693*
Storage			***60***	***60***	***120***	***120***							
Belle River Conversion			*517*	*517*									
Proxy CCGT w/CCS													*946*
Demand Response													
CVR/VVO				***8***	***8***	*7*	***8***	*7*					

Q135. What changes were made on the Preliminary PCA to determine the Final PCA?

A135. After we identified the Preliminary PCA, we started the five verification analyses that are part of step 6 of the IRP process from Figure 1 (e.g., resource adequacy, risk assessment, etc.). Around the same time, the IRA was enacted into law. The Company modeled a new scenario – REFRESH – to assess the impacts of the tax credit provisions for renewable energy, energy storage, nuclear, and CCGT with CCS. The results of this scenario and its associated sensitivities are discussed in more detail by Witness Manning in her testimony. The modeling results demonstrated that with the new tax credits it was more economic to include additional renewables in the plan and to add them earlier in the study period. Based on these results, the Company decided to incorporate the REFRESH modeling results into the final PCA. The process for designing the Final PCA was similar to the process for designing the preliminary PCA as discussed above. The considerations used in selecting the 7B sensitivity remained the same. The optimized 7B portfolio contains the Belle River conversion, the Monroe retirements in 2028 and 2035, the proxy CCGT w/CCS, solar, wind, and storage as seen in Table 25. Then, we phased in the solar and battery builds and constrained the wind build as discussed by Witnesses Hernandez and Manning in their testimonies. The CVR/VVO program was also added to continue to take advantage of waste reduction opportunities on the distribution system. In Table 25, the top box shows the build plan from the 7B retirement sensitivity run on the REFRESH scenario. Then, we made three adjustments to the 7B retirement schedule optimized build portfolio:

1. The solar build in 2026 was increased to 400 MW, in alignment with years 2027 and 2028;
2. 180 MW of additional battery was added; phased in from 2025 through 2028, instead of installing it all in one year; and
3. The CVR/VVO program was added in the years 2026 through 2030.

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After we made these adjustments, we reran the model on the REFRESH scenario to optimize the plan and the resulting optimization eliminated the DR program that had previously been selected in 2028. The bottom box shows the results, which is the first 10 years of the Company's Final PCA. The last 10 years were also determined in the EnCompass optimization.

Refer to Witness Leslie's testimony for additional details on the PCA.

Table 25: Evolution of the PCA

REFRESH_CASE_7B	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Additions										
Solar				*119*	*400*	*400*	*800*	*800*	*800*	*800*
Wind						*200*	*200*	*200*	*200*	*200*
Storage						***180***				*400*
Belle River Conversion			*517*	*517*						
Demand Response						*98*				
CVR/VVO										

REFRESH_ Final PCA	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Additions										
Solar				*400*	*400*	*400*	*800*	*800*	*800*	*800*
Wind						*200*	*200*	*200*	*200*	*200*
Storage			***60***	***60***	***120***	***120***				*400*
Belle River Conversion			*517*	*517*						
Demand Response										
CVR/VVO				***8***	***8***	*7*	***8***	*7*		

The final PCA was then verified with the five assessments described in Section 1.

Q136. Is the Company's proposed course of action the most reasonable and prudent plan that ensures resource adequacy, optimizes affordability, and makes progress towards further CO_2 reductions?

A136. Yes. The PCA is the most reasonable and prudent plan for meeting the Company's energy and capacity needs. The Company synthesized the results of comprehensive modeling and the assessments (resource adequacy, risk, environmental justice) discussed throughout my testimony to develop the most reasonable and prudent PCA that ensures resource adequacy, optimizes affordability, and progresses the DTE Electric CO_2 reduction goals.

Reliability is paramount when considering plans to retire large 24/7 coal fired generation resources. The PCA is a diverse portfolio and is economically robust under varying commodity prices as demonstrated by the risk analysis. The PCA will meet the resource adequacy standard of 1 day in 10 LOLE as verified by the SERVM model. The PCA reduces CO_2 and the other pollutants (e.g., NOx, SO_2, PM2.5, Hg) as quickly as possible while maintaining reliability.

The Belle River Power Plant conversion is a low-cost economical alternative that directly reduces and enables earlier fleet CO_2 reductions. DTE Electric's PCA utilizes the existing infrastructure at Belle River to facilitate an aggressive retirement of coal. Converting the Belle River coal-fired units to gas-fueled cycling operation (peaking resource) allows approximately 1,500 MW at Monroe to retire nearly 12 years earlier than planned. This would result in the accelerated retirement of approximately 2,500 MW of coal from Belle River and Monroe power plants by mid-2028 and drive subsequent accelerated CO_2 emissions reductions. This plan decarbonizes quicker when compared to the 2019 plan and the starting point, is less costly and maintains the high reliability needed to serve our customers.

The PCA also includes renewable and storage resources to further advance CO_2 reduction achievements. These renewable and storage resources will be added in a way that ensures reliability and supports further CO_2 reductions. Increased amounts of renewables also help to mitigate fuel and market volatility, as shown in the stochastic risk assessment.

In 2035, the PCA includes the full exit of coal for DTE Electric by retiring the last two units of the Monroe Power Plant, totaling about 1,500 MW. The PCA calls for a replacement with a very low CO_2 emitting resource (CCGT with 98.5% carbon capture and sequestration), as well as incremental 10,000 MW of renewables and 1,050 MW of storage from 2033-2042, leading to the retirement of the Belle River Power Plant peaking resource by 2040. Thus by 2040, DTE Electric would achieve its goal of 90% CO_2 emissions reductions while maintaining a balanced mix of resources.

Therefore, based on the above factors, the PCA is the most reasonable and prudent plan.

Q137. Does this complete your direct testimony?

A137. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAYLA D. MANNING

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

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Q1. What is your name, business address and who are you testifying on behalf of?

A1. My name is Shayla D. Manning (she/her/hers). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q2. What is your present position with the Company?

A2. I am a Manager in the Integrated Resource Planning business unit.

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 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 work experience do you have?

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 the cost impact to the system. 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 Report. In 2018, I accepted a role as Supervisor within the Corporate Energy Forecasting group, focusing on Long-Term forecasting. 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 a position as Supervisor within the Integrated Resource Planning group and was promoted to my current position of Manager in 2021.

Q5. What are your duties as Manager, Integrated Resource Planning?

A5. I am responsible for leading the modeling team that conducts production cost and capacity expansion modeling to support integrated resource planning, economic analyses, and long-term strategy.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission?

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

U-20373 2020-2021 DTE Electric EWR Plan

U-20527 2020 PSCR Plan

Line No.		
1	U-20373	Amended 2020-2021 DTE Electric EWR Plan
2	U-20826	2021 PSCR Plan

Line No.

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 2022 Integrated Resource Plan (IRP). My testimony is organized into the following sections:

I. Foundational overview and definitions
II. IRP model improvements
III. Resource planning and modeling process
IV. DTE Electric capacity position determination
V. Modeling inputs
VI. Scenarios and sensitivities
VII. IRP modeling tools (Aurora and EnCompass)
VIII. Belle River and Monroe retirement analysis
IX. Overview of the IRP analysis results

Q8. Are you sponsoring any exhibits?

A8. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-3.1	2022 IRP Report
A-3.2	2022 IRP Report Appendices
A-3.3	Starting Point Projected Capacity Position
A-3.4	PCA Projected Capacity Position
A-3.5	PCA Projected Revenue Requirement

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

A9. Yes, they were.

SECTION I: Foundational Overview and Definitions

Q10. Please describe the IRP resource planning and modeling team.

A10. DTE Electric's IRP team includes a modeling team that conducts the capacity expansion and production cost modeling for the Company's IRP and long-term generation planning, economic analyses, and strategy. I am responsible for managing this modeling team. Company Witness Cejas Goyanes is responsible for the planning and strategy team. Throughout my testimony when I refer to "the team" or "we", I am referring to the modeling team unless otherwise specified.

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.

Q12. What is a portfolio?

A12. A portfolio represents the resource plan the model determines to be the optimal plan based on market assumptions, resource alternatives, and other model inputs and constraints.

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

A13. Primarily, the team used EnCompass. The Company also hired a third-party consultant, Siemens (see Exhibit A-3.2, 2022 IRP Report Appendix E, for more information on Siemens), to develop long-term commodity prices. Siemens used the modeling tool, Aurora. Additionally, Witness Mikulan describes other supplemental modeling tools that were either ran by the team, other Company subject matter experts (SMEs) or other third-party consultants. The additional models include, DER-VET^{TM}, SERVM, transmission, and environmental justice models.

Q14. What is EnCompass?

A14. EnCompass is a power planning software by Anchor Power Solutions. DTE Electric 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 as it runs on a more granular level, representing the hourly dispatch and energy 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 then automatically 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 with 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 IRP team used as direct inputs into the EnCompass model.

Q18. How are scenarios and sensitivities defined?

[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.

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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 one specific uncertainty or variable. Modelers apply sensitivities to the scenarios.

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

A19. Yes. The Michigan Integrated Resource Planning Parameters (MIRPP) require that scenarios and sensitivities demonstrate multiple diverse scenarios and sensitivities (the high fuel sensitivity and the high load sensitivity) and are run "globally" across all three MIRPP scenarios. I discuss the scenarios and sensitivities the team modeled in Section VI 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 Section IV of my testimony.

Q21. What is Resource Adequacy in the context of this IRP?

A21. Resource adequacy is ensuring that DTE Electric has enough resources to serve its customers in all hours of the year with the Company's resources specified in a portfolio. Resource adequacy is related to reliability; if the DTE Electric fleet was not "resource adequate" to a target reliability standard, there would be a higher probability of customer interruptions i.e., load shed, due to lack of supply.

Q22. What is the 2022 IRP Report?

A22. The 2022 IRP Report, Exhibit A-3.1, is a comprehensive and consolidated report 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 modeling including scenarios and sensitivities, the outreach process, the development of the preliminary proposed course of action (PCA), the risk assessments, the final PCA, implementation plans for the PCA, rate impacts and financial information regarding the PCA, and environmental impacts of the PCA. The IRP report brings together in one place much of information included in the testimony of the witnesses in this case. Additionally, 2022 IRP Report Appendices can be found in Exhibit A-3.2.

Q23. What is the planning period examined in the IRP analysis?

A23. The planning period examined in the IRP analysis is 2023 through 2042.

SECTION II: IRP Model Improvements

Q24. Witness Mikulan discussed several improvements to the modeling process, including the use of a new IRP model and refinements to modeling assumptions. How was the new IRP model selected?

A24. The Company performed market research to determine the top capacity expansion modeling software tools available in the industry. The IRP team evaluated a total of nine modeling software programs to replace the Company's capacity expansion and production models, Strategist® and PROMOD®, respectively. After detailed exploration of each program, the Company selected four of the nine programs for further evaluation and analysis. The remaining four programs were Aurora and

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Plexos by Energy Exemplar, Capacity Expansion by ABB, and EnCompass by Anchor Power Solutions. The Company hosted a modeling software collaborative with stakeholders on May 11 and May 12, 2020. The collaborative included presentations and discussions from the three software vendors (Energy Exemplar, ABB and Anchor Power Solutions), the Electric Power Research Institute (EPRI), and four utilities including DTE Electric. The collaborative concluded with a stakeholder roundtable that included discussion and feedback around prioritization of criteria when selecting the next IRP modeling software.

The Company then evaluated each modeling software based on five main categories including model capabilities, transparency, functionality, value, and IRP process efficiency, as well as nice-to-haves. Each category had individual criterion for a total of 33. The criteria were determined both internally and based on external stakeholder feedback from the modeling software collaborative. A multiple-week software trial was performed on each model. A team of five modelers participated in each software trial and determined a consensus weighting and score for each criterion. The Company then used these scores in the weighted-sum decision making model to determine a final score for each category and each software overall. The Company selected the software with the highest score, which was EnCompass.

EnCompass had the highest score in every category, except functionality, where the second place Plexos had a higher score. EnCompass had higher scores in the categories of transparency, value and IRP process efficiency. Overall, the selection was driven by the criteria including best value for cost, intuitive interface, availability of a manual, and increased transparency.

Q25. Were there other process improvements made since the last IRP?

A25. Yes. With the team's transition to the EnCompass software, the team implemented several improvements to the modeling process that included the data assumptions input process, the modeling of existing resources, the modeling of solar-storage hybrid units, and emissions modeling. As explained by Witness Mikulan, the team also incorporated storage benefits and tiered effective load carrying capabilities (ELCCs) for solar and storage into the IRP model.

Q26. How was the data assumptions input process improved?

A26. In the last IRP, for modeling data assumptions, the IRP team created input templates, performed all calculations external to the model, and manually input the data into the Strategist® model. With EnCompass, the modeling team created input templates, which streamlined the process and created efficiencies, and imported them into the model directly, avoiding potential errors associated with manual data input. Additionally, the new input process provides increased transparency, as the data input into the model is identifiable. EnCompass also has the functionality to perform calculations within the program and the modeling team fully utilized this capability, where possible.

Q27. How was the modeling of existing resources improved?

A27. In the previous IRP, the Company modeled its existing coal, oil and natural gas fired resources as "must run" due to Strategist's limitations. Must run means that a resource is always on, between the minimum and maximum capacity of the resource (economic loading level). Additionally, under must run the model does not determine start up and shutdown decisions but decides upon the most economic loading level. Because Strategist® could not accurately capture start-up parameters, it was not possible to model resources through economic dispatch in a non-must-run state. The model would optimize the dispatch of the resources based on the start-up parameters and costs. The Company's current modeling program EnCompass, on the other hand, can accommodate numerous start-up parameter inputs allowing the model to better reflect a resource's dispatch throughout the study period. Through using EnCompass, the team made a concerted effort to model the start-up parameters and costs of the resources as accurately as possible. The team used these more detailed start-up parameters and costs in both capacity expansion and production cost modeling. Additionally, to fully implement this improvement, we separated the peaker fleet into individual peaking resources, in contrast to the last IRP, where several peakers were grouped into a single resource.

Q28. How was the solar-storage hybrid resource modeling improved?

A28. In the previous IRP using the Strategist® and PROMOD® models, a solar-storage hybrid resource could not be modeled easily or very accurately with respect to the source of charging power. With EnCompass, resources can be tied together and modeled with greater detail.

Q29. How has emission modeling improved?

A29. Previously with Strategist® and PROMOD®, both system and individual unit emission limits were manually enforced by having modelers review run results and adjust model parameters to reduce emissions, iterating until the emission limits were met. With the introduction of EnCompass, emission limits were adhered to automatically within the program, by setting the emission limit as a constraint.

DTE Electric also improved the modeling of carbon dioxide (CO_2) specifically by transitioning from post-simulation calculations of the annual net short method to the use of the hourly net short method within the simulation itself. Please refer to Witness Mikulan's testimony Section VI for more detail on the net short CO_2 accounting method.

Another improvement regarding emissions is the modeling of plant chemical usage. Previously, chemical usage for limestone and urea, for instance, was calculated on a spreadsheet after a model run was completed. In contrast, EnCompass automatically tracks the chemical usage within the model and includes it in the output of each portfolio. With this new capability, the team modeled several additional effluents such as carbon monoxide (CO), lead (Pb), mercury (Hg), and volatile organic compound (VOC).

SECTION III: Resource Planning and Modeling Process

IRP Process

Q30. What are the resource planning and modeling steps associated with conducting DTE Electric's 2022 IRP process?

A30. As mentioned by Witnesses Leslie and Mikulan in their testimonies, 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 2a, 2b, 4, and 5:

Line
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1. Review planning objectives
2. Develop inputs
    a. Determine scenarios and sensitivities
    b. Determine capacity position
    c. Develop supplemental modeling inputs
3. Develop resource alternatives
4. Conduct and iterate modeling
5. Analyze results
6. Initial synthesis of results and determine preliminary PCA
    a. Validate resource adequacy
    b. Conduct risk assessment
    c. Conduct environmental justice analysis
    d. Conduct financial analysis
    e. Verify grid reliability analysis
7. Synthesis results into final proposed course of action
8. File the IRP, and take part in the contested case

Witness Mikulan will discuss in more detail parts of steps 1, 2c, 3, 4, 6 and 7, and Witness Cejas Goyanes will discuss parts of steps 2c and 3 in their respective testimonies.

Q31. What inputs were developed under planning step two, "develop inputs"?

A31. The key inputs that the modeling team developed under planning step two include scenarios and sensitivities (step 2a) and capacity position (step 2b), which I explain in more detail later in my testimony. Other supplemental modeling assumptions (step 2c) are described in the testimony of Witnesses Mikulan and of Cejas Goyanes.

Q32. How was the modeling analysis conducted in step four, "conduct and iterate modeling"?

A32. 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. In 2021 the IRP team provided inputs and data to Astrapé to complete initial resource adequacy modeling. As explained in more detail by Witness Mikulan, Astrapé's modeling resulted in Effective Load Carrying Capabilities (ELCC) for solar and storage resources that the team incorporated into the IRP modeling process. Grid Reliability modeling was performed by ITC and is explained by Witness Roy in his testimony. From the modeling ITC performed, ITC provided transmission enhancement costs and the team incorporated them into the IRP modeling process. The Grid Reliability modeling also providing insights into potential impacts to the transmission systems.

The modeling team conducted the IRP optimization modeling using the software tool, EnCompass, explained in additional detail in Section VII 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 running 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. The median modeling time of the team's EnCompass run was approximately 5-6 hours. However, depending on the problem size and particular inputs of the modeling run, the solve time could be in excess of a day.

Q33. How were the results analyzed in step five, "analyzing results"?

A33. As mentioned, each EnCompass run resulted in a portfolio. Additionally, the model calculated the annual and net present value revenue requirements (NPVRR) for each portfolio. Under each scenario, the Company developed a "base" portfolio, which was comprised of the starting point and was the basis for comparison. All sensitivities under the appropriate scenarios were compared to that respective base portfolio.

There were three main aspects of a given portfolio that were assessed in the comparison, as discussed below:

1. **Completing a "delta" (change) analysis of the annual and net present value revenue requirement between the sensitivity and the base portfolio.** When we completed the delta analyses for each of the sensitivities under a scenario, the sensitivities were ordered from the highest revenue requirement savings to the lowest savings. As a result, we identified the least-cost portfolio through this ranking of sensitivities.

2. **Reviewing the resources that the model selected in the sensitivity's optimized portfolio.** By reviewing the selected resources, the team recognized commonalities, anomalies and trends between different portfolios.
3. **Reviewing the sensitivity's CO_2 tons emitted to ensure the Company's target of 80% carbon reduction was met by 2040.**

Reviewing the comparisons not only derives the least-cost plans across each scenario, it also provides a quality check of the results on 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, further analysis was needed such as risk assessment, environmental justice and resource adequacy modeling. We used these supplemental analyses as well as the results of this comprehensive modeling in the synthesis of results (step 6) that determined a preliminary PCA as described by Witness Mikulan.

SECTION IV: DTE Electric Capacity Position Determination

Starting Point

Q34. How was DTE Electric's starting point capacity position assessed in this IRP analysis?

A34. When IRP modeling began in December 2021, the team completed an assessment of the current state of the Company's capacity position, building off the Company's 2021 capacity demonstration filing. That assessment became the starting point of the IRP optimization modeling.

Q35. How is the capacity position determined?

A35. The capacity position is determined by totaling the existing and approved resources' unforced capacity,[2] including 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 MISO Planning Reserve Margin Requirement (PRMR).[4] The resultant difference would either be a projected capacity surplus or shortfall.

Q36. What resources are included in the starting point?

A36. The starting point is comprised of the following:

- Belle River Power Plant (Belle River) retirement on May 31, 2028
- Monroe Power Plant (Monroe) retirement on December 31, 2039
- 1,611 MW of approved renewables to meet the renewable portfolio standard (RPS) including 59 MW of approved RPS projects to be completed by 2024
- 1,432 MW of approved voluntary green pricing (VGP) renewables including 897 MW of approved VGP projects to be completed by 2025
- 2% Energy Waste Reduction (EWR) in 2023, then the maximum amount of achievable EWR potential identified in the 2021 Michigan Energy Waste Reduction Statewide Potential Study or "EWR Statewide Potential Study"

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[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.
[4] See MISO Tariff, Module E-1, Section 68A.7.

- 920 MW of Demand Response (DR) in 2023 increasing to 949 MW in 2026 (Unforced Capacity)
- 29 MW of approved conservation voltage reduction/volt-var optimization (CVR/VVO)
- Existing Purchase Power Agreements (PPAs), peaking facilities, Ludington, and Fermi continue to be operational throughout the study period

These starting point resources comprise the Planning Resources, used in assessing the capacity position.

Q37. Was a starting point capacity shortfall identified in the first five years, 2023 - 2027, of the study period?

A37. No, a capacity shortfall was not identified in the first five years of the study period from 2023 to 2027. 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 detail on the determination of the PRMR. Refer to Exhibit A-3.3 Starting Point Projected Capacity Position for the annual detail.

Q38. Was a starting point capacity shortfall identified in the second five years, 2028 - 2032, of the study period?

A38. Yes, the capacity assessment we conducted forecasted a starting point capacity shortfall beginning in the 2028-2029 planning year. In Planning Year 2028-2029, as shown in Exhibit A-3.3, the PRMR forecast is 10,572 MW and the projected planning resources total is 10,307 MW, thereby resulting in the projected capacity shortfall of 265 MW. The forecasted capacity shortfall is driven by the starting point planned retirement of the Belle River Power Plant on May 31, 2028.

Q39. Why is the capacity position calculated using the PRMR?

A39. The Midcontinent Independent System Operator, Inc. (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.

Q40. Can you describe Exhibit A-3.3 Starting Point Projected Capacity Position for the years 2023 through 2042 in more detail?

A40. Exhibit A-3.3 identifies the capacity position that the team used to begin the Company's IRP optimization modeling. The exhibit is similar to the Capacity Demonstration format developed by the MPSC Staff for presenting utility capacity positions. The PRMR and Unforced Capacity (UCAP) of resources are consistent with the most recent, 2021 Capacity Demonstration filing. Column (a) lists the capacity categories. Column (b) through (l) contain the annual values for each planning year, which runs from June 1 through May 31. Lines 1-6 detail the calculations to derive the adjusted peak demand, which applies the MISO coincident factor[6] to system peak. Lines 7-11 detail the calculations that derive the PRMR, or the peak demand plus planning reserve margin. Lines 12-22 detail the

[5] MISO Tariff Module E-1 Section 68A, 69A-1 https://www.misoenergy.org/legal/tariff/, accessed October 15, 2022.

[6] MISO coincident factor is the ratio of coincident peak of MISO connected loads to the sum of peaks of the individual connected loads.

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Company's planning resources. Finally, line 23 identifies the capacity position by subtracting the Total MISO Planning Requirement (line 11) from the Total DTE Electric Planning Resources (line 22) to determine the surplus, if positive, or the shortfall, if negative.

PCA

Q41. Can you describe Exhibit A-3.4 2022 IRP PCA Projected Capacity Position?

A41. Exhibit A-3.4 reflects the capacity information from the Starting Point Capacity Position (Exhibit A-3.3) along with the added and retired resources from the PCA as described in Section VIII. Exhibit A-3.4 is in the same format as Exhibit A-3.3 as described above. In this exhibit, a line has been added to include the retired resources and another line was added to include the new resources from the PCA.

SECTION V: Modeling Inputs

Q42. What technologies and/or resource alternatives were considered in the EnCompass model?

A42. As Witnesses Mikulan and Cejas Goyanes discuss in their testimonies, the Company conducted a review of alternatives. The resource alternatives included in EnCompass are:

- Natural gas
  - Combustion Turbine (CT)
  - Combined Cycle (CCGT) with and without carbon capture and sequestration (CCS)
  - Aeroderivative CT
  - Reciprocal Industrial Combustion Engine (RICE)
  - Coal to natural gas conversion

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- Renewable[7]
  - Wind
  - Solar (utility scale and customer owned distributed)
  - Solar-storage hybrid
  - Municipal waste
  - Wood and Biomass
- Lithium-ion battery
  - 4-hour duration (utility scaled and customer owned distributed)
  - 8-hour duration
  - 10-hour duration
- Nuclear
  - Small modular nuclear reactor (SMR)
  - Extended power uprate (EPU) at Fermi Power Plant
- Combined Heat and Power (CHP)
- EWR (levels described by Witness Bilyeu)
- DR (programs described by Witness Farrell)
- CVR/VVO (described by Witness Musonera)
- Market capacity purchases (modeled in select sensitivities)

Q43. How were the resource alternatives evaluated in EnCompass?

A43. The team modeled the alternatives as supply side resources in the EnCompass model with associated capacities, operating parameters, capital expense, and ongoing costs. The natural gas, lithium-ion battery, nuclear, CHP, distributed generation (DG), and renewable resources were all modeled as projects that the

[7] 2008-PA-0295.pdf (mi.gov) , accessed October 15, 2022.

model could select in any given year between 2024 and 2042 (actual year is dependent on construction time and commercial availability, see Table 1 for specifics). EWR, DR, CVR/VVO, and market capacity purchases were modeled using different approaches to appropriately capture the assumptions, which are described in more detail below.

Q44. How were EWR alternatives evaluated in EnCompass?

A44. As described by Witness Bilyeu, the Company evaluated six levels of EWR in the IRP: reference (based on maximum achievable potential of the EWR Statewide Potential Study), 1.5%, 2.0%, 2.5% until 2033 then to EWR Statewide Potential Study, 2.5%, and 3.0%. The six different levels of EWR consist of different mixes of specific EWR end-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 Musonera's testimony while the remaining EWR inputs are described in more detail by Witness Bilyeu 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 we modeled the EWR alternatives as resources 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). We 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. We calculated the net present value (NPV) of end effects for each level of EWR and incorporated that data into EnCompass as a negative cost adder to reflect the benefit.

In each EnCompass run, the model could select from the six levels of EWR as a resource in 2023 (first year) and remain at the level for the entire study period. 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 Bilyeu in his testimony, but also limits the amount of resources included in EnCompass. Although EnCompass does not have a theoretical limit on the number of resources 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 does as well. To allow the model to vary between the six different levels of EWR, over the 20-year study period, would have added 120 different resources, which would have significantly increased modeling time.

Q45. How was DR evaluated in EnCompass?

A45. For this IRP, Witness Farrell provided various DR programs from the 2021 Demand Response Statewide Potential Study (DR Statewide Potential Study), along with those programs' respective annual capacities and costs. The Company modeled each DR program as an individual supply-side resource and modeled the cost for each program. The model had the option to select each program between 2023 and

2025 (depending on the program) until the end of the study period in 2042. Additionally, we modeled the Company's existing DR portfolio on an individual program basis. These programs could dispatch to reduce capacity needs according to constraints provided by Witness Farrell. See Witness Farrell's testimony for further discussion of DR and its role in this IRP.

Q46. What is CVR/VVO and how was it evaluated in EnCompass?

A46. CVR 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 represented one circuit of CVR/VVO at 0.15 MW, with a maximum of 50 incremental circuits per year and cumulative maximum of 315 circuits over the study period. CVR is further explained by Witness Musonera.

Q47. How were market energy purchases and sales evaluated in the IRP?

A47. The model was set up to allow hourly energy spot purchases and sales between DTE Electric and MISO based on economics. The energy sales limit was 2,000 MW per hour and the energy purchase limit was 2,400 MW per hour. The limits were based on historical energy market purchases and sales.

Q48. How were market capacity purchases evaluated in EnCompass?

A48. Market capacity purchases represent potential capacity that could be purchased in the annual capacity auction; however, market capacity purchases were not available in most 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. Refer to Section VI of my testimony for additional details on capacity purchase sensitivities. Witnesses Leslie and Burgdorf, in their respective testimonies, provide additional context on the regional capacity outlook relevant to market capacity purchase assumptions.

Q49. How were DG resources modeled in the IRP?

A49. 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, as described in more detail by Witness Leuker in his testimony. The team also ran two aggressive DG adoption sensitivities based on alternative load forecasts provided by Witness Leuker. See Section VI for more information on the sensitivities. Additionally, the IRP team modeled customer-owned residential and commercial distributed solar and batteries as supply side resources and offered these resources to the model as capacity expansion resource alternatives. The cost and operating characteristics of these resources came from NREL Annual Technology Baseline as discussed by Witness Cejas Goyanes in his testimony.

Q50. What was the starting year the resources could be selected in the model?

A50. The starting year is based upon how soon the resource could come online either due to the assumed construction period or technology maturity. The starting years for the resources in the optimization model are shown in Table 1.

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Table 1: Starting Year of Resources in Capacity Expansion Modeling

Technology	**Starting Year**		**Technology**	**Starting Year**
CT	2025		Wood and biomass	2027
CCGT	N/A		Utility-scaled lithium-ion battery	2024
CCGT w/CCS	2028		Lithium-ion battery DG	2023
Aeroderivative CT	2025		SMR	2035
RICE	2025		EPU	2035
Wind	2026		CHP	2025
Utility-scaled solar	2025		EWR	2023
Solar DG	2023		DR	2023
Solar-storage hybrid	2025		CVR	2026
Municipal waste	2026			

Q51. Why is there no starting year for the CCGT?

A51. CCGT resources were constrained from selection in the model (except for select sensitivities) to ensure that the portfolios would be on a trajectory to achieve net zero carbon reduction by 2050. CCGT resources are very economic as shown in the levelized cost of energy (LCOE) analysis presented by Witness Cejas Goyanes in this testimony. Based on this, CCGTs would likely be selected in the optimization and potentially included in the least-cost portfolios. Therefore, only CCGTs with CCS were available as alternatives to ensure the least-cost portfolios would include resources that support the Company's efforts to reach its net zero carbon reduction goal.

Q52. Were any constraints modeled limiting the number of resources that could be selected in the optimization?

A52. Yes, the team modeled different constraints for the various resources included in the optimization, as shown in Table 2.

Table 2: Resource Constraints

Resource Type	Constraint throughout the study period
CCGT w/ CCS, CT, Aeroderivative CT, RICE, SMR	2 of each resource type available to be selected
Municipal waste	1 resource available to be selected
CHP	Up to 27 MW to be selected
Utility-scaled wind, utility-scaled solar	Up to 500 MW per year (combined) prior to 2026; in 2026 and beyond up to 1,000 MW per year (combined) to be selected
Utility-scaled lithium-ion battery	Up to 500 MW per year prior to 2027; 800 MW per year between 2027 and 2039; up to 1,200 MW per year between 2031 and 2035; and up to 2,000 MW per year after 2035 to be selected

Q53. What is the basis for the constraints listed in Table 2?

A53. As mentioned previously, EnCompass does not have a theoretical limit on the number of resources that can be included in its optimization, but 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 does as well. To reduce this issue, certain constraints or limits were introduced. Natural gas fueled resources were constrained to ensure the Company would be on the path to its carbon neutral goals. Offering the model an abundance of natural gas resources could present challenges to achieving carbon reductions. The constraint regarding the SMR was determined by its technology maturity level as explained by Witness Mikulan in her testimony. It is a maturing technology that is not available to be selected in the model until 2035, therefore offering the model two units within the years left in the study period was appropriate. The municipal waste constraint was based on a 2019 US Department of Energy (DOE) study[8] that provided information on current market saturations. The MW constraint on the CHP was based on a potential study conducted by ICF. Lastly, the constraints for renewables and storage were based on guidance from the Company's SMEs. Witness Hernandez explains the constraints for wind and solar in her testimony and Witness Morren describes the constraints regarding storage in his testimony.

SECTION VI: Scenarios and Sensitivities

Q54. What scenarios were developed for this IRP?

A54. The DTE Electric 2022 IRP utilized eight scenarios; three that were required under the Michigan Integrated Resource Planning Parameters (MIRPP), pursuant to the Commission's order implementing section 6t of 2016 PA 341; a fourth required under the Executive Directive 2020-10, pursuant to the Commission's order in Case No. U-20633; scenarios five and six, specifically developed on Company assumptions (Reference (REF) and High Electrification (HE)); scenario seven was developed through collaboration of our stakeholders (STAKE), and finally an eighth, a refresh of the REF incorporating updated natural gas prices, wholesale electricity prices and the Inflation Reduction Act (IRA) tax credit impacts (REFRESH). The required scenarios included Business as Usual (BAU), Emerging Technologies (ET), Environmental Policy (EP), and Carbon Reduction (CR). For

[8] https://www.energy.gov/sites/prod/files/2019/08/f66/BETO--Waste-to-Energy-Report-August--2019.pdf, accessed October 15, 2022.

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each of the eight 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.

Q55. What are underlining assumptions of the required scenarios?

A55. The required scenario assumptions:

1) ***Business as Usual (BAU):*** This scenario assumes that thermal and nuclear generation retirements in the modeling footprint were driven by a maximum age assumption, public announcements, or economics. The demand and energy remain at low growth rates. The BAU gas forecast was based on the 2021 Annual Energy Outlook from the U.S. Energy Information Administration "Natural Gas: Henry Hub Spot Price: Refence Case" (2021 EIA gas forecast[9]). This scenario does not include a CO_2 emission cost adder.

2) ***Emerging Technologies (ET):*** This scenario assumes that technological advancements and economies of scale resulted in an assumed 35% reduction in technology costs for EWR, DR, battery storage, and solar. Retirements of all coal units were considered. The 2021 EIA gas forecast was used for this scenario as well as no CO_2 emission cost adder.

3) ***Environmental Policy (EP):*** This scenario assumed tighter carbon regulation by targeting a 30% CO_2 reduction by 2030. Coal units primarily retired based on the amount of carbon emissions, then economics. The wind and solar capital costs were

[9] https://www.eia.gov/naturalgas/reports, accessed October 15, 2022.

assumed to be reduced by 35%. All other technologies' costs were unchanged from the BAU scenario. The 2021 EIA gas forecast was used for this scenario, as well as no CO_2 price to achieve the 30% specified CO_2 reduction.

4) ***Carbon Reduction (CR):*** This scenario is required under the CO_2 Executive order, pursuant to the Commission's order in Case No. U-20633. Per the requirements, this scenario was based on the EP scenario with the high load growth forecast and considers two distinct carbon reduction goals: 28% and 32% carbon reduction by 2025.

Q56. What do the three scenarios based on DTE Electric assumptions consist of?

A56. The three scenarios based on DTE Electric assumptions are the Reference, High Electrification, and Reference Refresh:

1) ***Reference (REF):*** This scenario most closely aligns the Company's internal planning assumptions, forecasts, and goals. The Reference scenario utilizes DTE's gas forecast and incorporates DTE Electric's CO_2 goals. A CO_2 price was included in 2027 at $5 per ton continuing up to $11 per ton in 2040 (real 2020 dollars). All technology costs for this scenario came from publicly available sources, consistent with the four required scenarios identified prior.

2) ***High Electrification (HE):*** The HE case includes an electric vehicle adoption assumption of 50% of light-duty sales, 30% of medium duty sales, and 100% of bus sales are electric by 2030 in Michigan, consistent with the draft MI Healthy Climate Plan.

3) ***Reference Refresh (REFRESH):*** In light of the recent trends in natural gas and wholesale electricity prices and the Inflation Reduction Act introduced in August 2022, this scenario is an update to the Reference scenario to capture these impacts.

Q57. What does the Stakeholder scenario consist of?

A57. As discussed by Witness Mikulan in her testimony, the Company collaborated with technical stakeholders to develop a scenario based on input received. The STAKE scenario reflects the *draft* Michigan Healthy Climate Plan[10] that was released in April 2022 as well as various other assumptions including:

- 2% EWR annually through 2042
- 100% Carbon neutrality by 2050 and approximately 80% CO_2 reduction by 2030 in Michigan
- 50% Michigan Renewable Portfolio Standard (RPS) by 2030
- All coal retired by 2035 for the entire Eastern Interconnect (based on President Biden's Plan)
    - Retirement of Belle River Units 1 and 2 in 2025 and 2026, respectively
    - Retirement of Monroe by 2035 (Units 3 and 4 in December 2028 and Units 1 and 2 in December 2034)
- DTE Electric resources (and rest of Zone 7): No new gas units, including RICE, CTs and CCGTs w/ CCS; green[11] Hydrogen (H_2) fueled peakers were available in the optimization for selection
- NREL advanced costs for renewables and batteries

[10] https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan, accessed October 15, 2022.
[11] A carbon-free hydrogen fuel produced by renewable energy

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- Electrification: High electric vehicle demand including 50% of light-duty sales, 30% of medium duty sales, and 100% of bus sales are electric by 2030 in Michigan

Q58. What specific sensitivities are reflected in the IRP?

A58. The MIRPP provides several required sensitivities, and the Company developed several on its own. Each sensitivity was applied to one or more scenarios. Most sensitivities were performed on the REF scenario, as the Company considers it the most probable and it provides a common base under which to compare each sensitivity against the others. See details regarding which sensitivities the Company modeled on each scenario in Section IX. An overview of the sensitivities is described below:

Energy Waste Reduction (supported by Witness Bilyeu): Several levels of EWR were modeled including 1.5%, 2.0%, 2.5% to 2033, 2.5%, and 3.0%.

Load (supported by Witness Leuker):

1. High load growth
2. Return of 50% Retail Choice load
3. Aggressive customer owned distributed generation
4. High electrification (starting point of the HE scenario)
5. Stakeholder with high adoption of electric vehicles (starting point of the STAKE scenario)
6. Stakeholder scenario with 25% distributed generation growth through 2030
7. Stakeholder scenario with high fuel switching

8. Electric Choice Cap increases to 15%
9. Climate change

Resource Alternatives: A MIRPP required sensitivity applied on the BAU where we restricted the model to only allow combustion turbines to be selected as a replacement technology.

Retirements: In the REF scenario, the team ran 19 different sensitivities with various retirement dates of Belle River and Monroe Power Plants. The team also ran six coal retirement sensitivities on the ET scenario. Additionally, a sensitivity was conducted to determine the optimal replacement(s) for the peakers that were identified for potential retirement through the peaker analysis process. See Witness Morren for additional details on the peaker analysis.

Renewables & Storage: The team modeled various sensitivities involving different levels of renewables and storage. Sensitivities regarding renewables **(**supported by Witness Hernandez**)** include the 2022 Request for Proposal (RFP) results and potential increases in the VGP Program. The storage sensitivity was driven by feedback from external stakeholders requested on the STAKE scenario and is detailed later in this section.

Transmission / Capacity Purchases: There were two sensitivities conducted, each on the REF and BAU scenarios, where capacity purchases were allowed up to 650 MW per year starting in 2030, after all projects are expected to be completed. The 650 MW is an assumption that represents DTE Electric's allocation of the approximately 1,300 MW of additional import capability described in the MISO Long Range Transmission Planning (LRTP) Tranche 1 Portfolio Report[12] explained in more detail by Witnesses Roy in his testimony. As Witness Roy mentions, the Capacity Import Limit (CIL) is not allocated to any particular utility. To model the value of the capacity purchases available, the team used the fundamental capacity price forecast provided by Siemens, explained in Section VII.

Gas Prices: The team ran sensitivities on each of the BAU, ET and EP scenarios, which increased the gas price by 200% to determine the impact of higher gas prices due to current market uncertainty.

Demand Response (supported by Witness Farrell): The team modeled three levels of potential for demand response programs as sensitivities. The 2021 DR Statewide Potential Study determined the three levels as Reference, Aggressive and Carbon Price.

Carbon Reduction Targets: For the CR scenario, the team completed two sensitivities based on specific carbon reduction targets of 28% and 32% by 2025.

Ancillary Service: Two sensitivities were completed to understand the impact of allowing existing and new resources to participate in the frequency regulation and spinning reserve markets in addition to the energy and capacity markets the other runs are based on. Including the additional ancillary service markets increased the problem size and modeling time of the EnCompass runs, therefore allowing the

[12] MTEP21 Addendum-LRTP Tranche 1 Report with Executive Summary625790.pdf (misoenergy.org) , accessed October 15, 2022.

resources to participate in the ancillary service market was only performed as a sensitivity.

Q59. Were there any sensitivities submitted by stakeholders?

A59. Yes. The sensitivities submitted by stakeholders included:

1. Retail Choice cap raised from 10% to 15% by June 1, 2024
2. Different levels of capacity prices
3. CO_2 prices of $2.50/ton in 2025 increasing by $2.50/ton each year
4. 50% decrease in gas prices

The team modeled sensitivity 1 on the BAU scenario because there was a required sensitivity involving different Retail Choice caps, therefore the two could be compared against the other. Sensitivity 3 was modeled on the STAKE scenario to understand the impacts of this scenario, since it did not have a carbon price associated with it originally. Sensitivities 2 and 4 were not modeled. As mentioned previously, market capacity purchases were not available in the modeling, with the exception of two sensitivities, therefore adding different levels of capacity prices would not impact the results. Additionally, the Company did not run sensitivity 4 because the model would have selected gas-fueled units as being economic. Decreasing gas prices further would not have changed the outcome of the model runs.

Q60. Were there sensitivities requested by stakeholders to be modeled specifically on the STAKE scenario?

A60. Yes, there were twelve sensitivities requested by stakeholders for the STAKE scenario:

1. Retire two Monroe units by December 31, 2028, and the remaining two units by December 31, 2030
2. Offer all gas technologies to the model (EIA assumptions)
3. Update RICE technology capital costs to approximately $890/kW and offer all gas technologies to the model
4. Constrain to 80% CO_2 reduction by 2030
5. 3% EWR annually through 2042
6. 3% EWR annually through 2042 and additional building heat fuel switching from natural gas end-uses to electric at a rate of 50% saturation by 2042
7. 25% annual growth of solar DG from 2023-2030; 15% annual growth 2031-2042
8. Double VGP resources (from 465 MW wind and 335 MW solar by 2025)
9. Battery installation standard of 482 MW by 2025; 1,205 MW by 2030; and 1,928 MW by 2040
10. Combine sensitivities 1 and 9 and 10% DG solar by 2030
11. Retire two Monroe units by December 31, 2028 and the remaining two units by December 31, 2030, and include four hydrogen-fueled CTs in 2031
12. Retire two Monroe units by December 31, 2028, and the remaining two units by December 31, 2030, convert Belle River to natural gas and include two hydrogen-fueled CTs in 2040

Sensitivity 11 was based on stakeholder feedback from the third technical conference in August 2022. At the conference, the IRP team discussed the need for

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approximately 1,000 MW of dispatchable resources due to reliability concerns after the full retirement of the Monroe Power Plant. Sensitivity 12 was also added after the third technical conference based on a stakeholder request.

Section VII: IRP Modeling Tools (Aurora and EnCompass)

Q61. As previously mentioned, the modeling conducted in the IRP analysis is an iterative process between the main IRP optimization modeling, Resource Adequacy modeling and Grid Reliability modeling. What models were used directly by the IRP team in the IRP analysis?

A61. The EnCompass model was the main resource planning tool used by the IRP team for the IRP analysis and Siemens used Aurora to perform the modeling to derive the fundamental forecasts used in EnCompass. The team also ran an EPRI model called DER-VET™ to model storage benefits, as described further by Witness Mikulan in her testimony. The output of DER-VET™ was used as an input into the EnCompass model. Additionally, there were other models used to develop modeling inputs, not performed by the Company. Refer to testimonies of Witnesses Mikulan and Roy for additional information on modeling tools used for Resource Adequacy and Grid Reliability modeling.

Aurora

Q62. What is a fundamental forecast?

A62. 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 accurate projections for long-term analysis when compared to an extrapolation of a forward price curve for 20 years.

Q63. How were the energy market prices used in the IRP models determined?

A63. The energy market prices used in the IRP model were determined by blending the energy market forward pricing with the fundamental forecast in years 2023-2025 to smoothly shift to the fundamental energy price forecast in 2026. The blending methodology applied a ratable adjustment between the forward prices and the fundamental forecast. The team used this methodology until the end of 2025. For years 2026 to 2042, 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 with the exception of the REFRESH scenario as we wanted to understand the full impact of the forward market from 2023 to 2027 as opposed to applying the blending methodology.

Q64. Did Siemens run the fundamental forecast model for all eight scenarios?

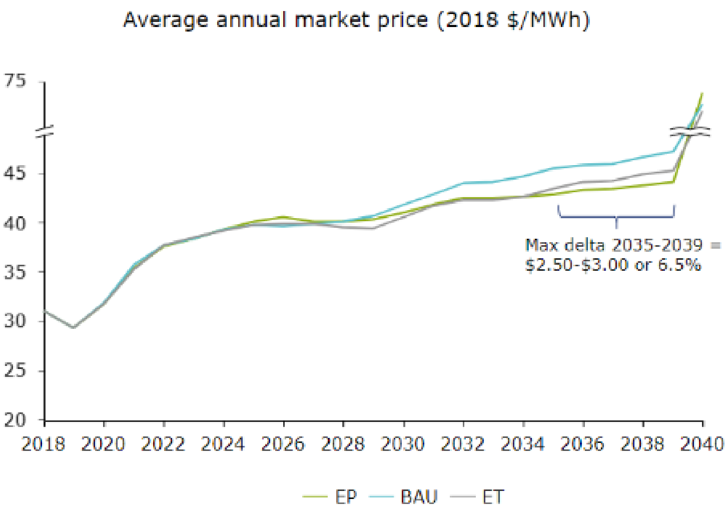
A64. No. The fundamental market forecast model was run seven times for the following scenarios and sensitivities:

- Reference scenario
- High Electrification scenario
- Stakeholder scenario
- MIRPP scenarios (BAU, EP, ET, and CR)
- High CO_2 Price sensitivity

- High Gas sensitivity
- Reference Refresh scenario

For the REF scenario, the fundamental supply-and-demand model generated the forecasts for gas prices, other fuel prices, and energy prices based on input assumptions including loads, capacity costs for new technologies, and CO_2 assumptions. The HE scenario kept the same assumptions as the REF scenario with the exception of the load forecast. The REFRESH scenario used current forward natural gas prices along with the 2022 EIA natural gas price forecast as inputs into the fundamental model to derive correlated market prices, however, all other assumptions remained the same as the REF scenario. For the other scenarios (BAU, ET EP, CR and STAKE) where a specific gas price was required, the gas prices at Henry Hub were input into the fundamental model rather than output, and the energy prices were the output. The Eastern Interconnect fundamental model was run once for all of the required scenarios (BAU, EP, ET, and CR) and the same energy prices were used in all four scenarios. The decision to use one market price forecast for all four scenarios was based on the minimal differences in market prices observed when running the BAU, EP, and ET for the 2019 IRP as shown in Figure 1.

Figure 1. Average Market prices from the 2019 IRP



Using the relevant information from the 2019 IRP, the market prices for the MIRPP scenarios were in-line with each other for the majority of the study period. Differences were noted in the last five years of the study period, 2035-2039, with maximum market price differentials of only 6.5% noted during that timeframe. Based on this, the Company determined that it would use one representative market price for the MIRPP scenarios in this IRP. This allowed additional flexibility to run the additional scenario and sensitivities including the Stakeholder scenario.

Q65. How was the gas price forecast determined for the IRP analysis?

A65. 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 Pratt in all scenarios (except for the REFRESH and high gas sensitivities) with the fundamental forecast from Siemens in years 2023-2025. For the years 2026-2042, the team used the fundamental prices for the Reference and High Electrification scenarios. Aligning with the market price forecast for the REFRESH scenario, forward natural gas prices were used from

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2023 to 2027. The 2022 EIA natural gas price forecast was used for the period 2028 to 2042 in the REFRESH scenario. For the remaining scenarios, the 2021 EIA forecast was used as described in Section VI. 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 Pratt's testimony.

Q66. How was the capacity price forecast used in the IRP modeling determined?

A66. The capacity price forecast was part of the market forecasts derived from Siemens. The use of the Siemens' forecast is consistent with the Company's recent 2023 PSCR filing, Case No. U-21259. For more details regarding the capacity price forecast, see Exhibit A-3.2 2022 DTE Electric Integrated Resource Plan Report Appendix F. As mentioned previously in Section VI, capacity purchases were not available for the model to select in model runs with the exception of two sensitivities.

Q67. How were the coal price forecasts determined for the IRP models?

A67. Coal prices were the same across all scenarios. The team added coal commodity costs to the applicable transportation rate (including railcar costs, if applicable) to determine the delivered cost of coal, by route, to each generating facility. We used a methodology that started with forward prices provided by Witness Pratt from 2023-2026. For 2027 and beyond, the Siemens' fundamental forecast inflation associated with coal prices was applied to the last year of the forward pricing.

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Q68. How were the environmental allowance adders used in modeling determined?

A68. The team established Nitrogen Oxide (NO_X) and Sulfur Dioxide (SO_2) adders to meet the constraints imposed by the Cross State Air Pollution Rule (CSAPR); the same prices were used in all scenarios since we assumed no change in NO_X and SO_2 policy across scenarios. For Carbon Dioxide (CO_2), there is no CO_2 adder in the BAU and ET scenarios, as the MIRPP did not define a constraint in those scenarios. In the EP scenario, which specified a 30% CO_2 reduction, we determined through fundamental modeling that the model output met the 30% CO_2 reduction target without using a CO_2 adder. Therefore, there is no CO_2 adder in the EP scenario.

The REF, HE, and REFRESH scenarios incorporated an allowance price adder for CO_2. The team set the first year of CO_2 prices in 2027 due to potential aggressive climate change policy from the Biden Administration, assuming a phase-in period would occur prior to implementation. The price level was set to represent a risk-weighted average, between zero prices and moderate prices (real $20-30/ton), from 2027 to 2042. The level was enough to change the dispatch, although not high enough to increase customer rates excessively, as could happen with moderate or higher price levels.

Q69. What is the purpose of a CO_2 emission cost adder?

A69. A CO_2 emission cost adder, in terms of ($/ton) emitted, was applied to the dispatch price of each generation resource in the dispatch model as an incremental cost and assumes that potential future environmental regulation will potentially apply a cost to emitting CO_2. Resources that emit more CO_2 are penalized by having a higher dispatch price due to the application of the CO_2 adder. These resources are therefore less economical, would be dispatched less and would run less than resources that emit less or no CO_2. CO_2 emissions and carbon accounting are further discussed by Witness Mikulan in her testimony.

EnCompass

Q70. How does the EnCompass capacity expansion model function?

A70. 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. EnCompass uses the typical day of the week construct during the capacity expansion runs to reduce the problem size to one that can be solved. This construct reduces the number of days per month to seven.

Q71. How were storage benefits incorporated into the EnCompass model?

A71. Storage benefits modeling was conducted by the modeling team in a supplemental modeling tool called DER-VET™ and explained in detail by Witness Mikulan in her testimony. The results of the tool were included in the EnCompass modeling for storage as a negative cost adder for up to 180 MW of stand-alone storage resources.

Q72. How were the seasonal and operational characteristics of the resource types handled?

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A72. The team modeled coal, gas, storage, and landfill gas resources in EnCompass to be economically dispatched. For other resources such as solar, wind, EWR, and renewable contracts such as landfill gas (LFG), 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 created a monthly maximum capacity time series instead of a 'Net Dispatch Limit %.' This methodology was used because the team assumed the resource will operate at a constant capacity throughout each month to hit an energy target. Fermi cannot be turned on and off quickly or easily and is incapable of ramping.

Q73. How does the model consider forced outages?

A73. Within both the capacity expansion and production cost runs, the model takes the random outage rate percentage (ROR %)[13] of that percent across all hours of the simulation period.

Q74. How were derates modeled within Encompass?

A74. 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 derate14, the percentage specified was (Max Cap-Derate)/Max Cap*100.

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[13] Random outage rate percentage, https://www.eia.gov/tools/glossary , accessed October 15, 2022.- "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."

[14] https://www.eia.gov/tools/glossary , accessed October 15, 2022 defines a derate as "A decrease in the available capacity of an electric generating unit" and "commonly due to: A system or equipment modification or Environmental, operational, or reliability considerations."

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Q75. How was seasonal or limited availability of a resource handled in Encompass?

A75. We handled seasonal or limited availability 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 Cejas Goyanes in his testimony.

Q76. How does the EnCompass production cost modeling function?

A76. After the team performs a capacity expansion run, we then use 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.

Q77. Does EnCompass produce revenue requirements for the modeled portfolios?

A77. Yes, EnCompass produces revenue requirements on an annual basis for each modeled portfolio. The model bases the revenue requirements on the inputted financial assumptions and technology costs described by Witness Cejas Goyanes in his testimony, as well as operating costs of both existing and new resources that the team input into the model. The EnCompass revenue requirement component accounts for 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 pass through costs and were included in the overall revenue requirement of the portfolio.

Q78. Was the existing generation fleet modeled in EnCompass?

A78. 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 PSCR forecasts. The Company obtained the operating units' input for the IRP scenarios in December 2021, as explained further by Witness Burgdorf in his testimony. 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 Hernandez's testimony.

Q79. What level of Public Utility Regulatory Policies Act (PURPA) purchases were assumed?

A79. The Company included unchanged existing PURPA contracts (50 MW) throughout the study period (2023-2042) in the starting point for all scenarios, representing expected renewal of all existing PURPA contracts.

Q80. How can interested parties obtain copies of the EnCompass model?

A80. 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. EnCompass is a complex tool and highly dependent on the input data and assumptions to derive reasonable results.

Section VIII: Belle River and Monroe Retirement Analysis

Q81. What are the IRP filing requirements with respect to the coal unit retirement analysis?

A81. The filing requirements include coal retirement analysis specifications. The December 20, 2017 MPSC order in Case No. U-18461, Michigan Integrated Resource Planning Parameters under Scenario 2, Emerging Technologies states that:

> Company-owned resource retirements may be defined by the utility, however, a meaningful analysis of whether coal units should retire ahead of business as usual dates should be performed. Retirements of all coal units except the most efficient in the utility's fleet should be considered, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics. [P. 18]

Q82. Was a coal unit retirement analysis performed on other scenarios in addition to the Emerging Technology scenario?

A82. Yes, the Company performed an extensive coal unit retirement analysis on its remaining coal resources in the Company's fleet, the Belle River and Monroe Power Plants, under the Reference scenario. The team further analyzed six portfolios with varying retirement dates from the Reference scenario under the Emerging Technology scenario.

Q83. What are the starting point assumptions for the retirement analysis?

A83. The starting point for the retirement analysis and the starting point retirement dates (Belle River in 2028 and Monroe in 2039) are consistent with the starting point of the capacity position determination described in Section IV.

Q84. What retirement years were modeled in EnCompass for the coal unit retirement analysis sensitivities?

A84. For Belle River, the team modeled both a staggered retirement (Unit 1 retired in a given year and Unit 2 retired in a separate year) and full retirement. This included the staggered retirement of Belle River Units 1 and 2 in 2024/2025 and 2025/2026, respectively, and modeled a full retirement for 2027 and 2028. For Monroe, both a staggered (Units 3 and 4 retired in a given year and Units 1 and 2 retired together in a different year) and full retirements were modeled. This included the staggered retirement of the Monroe units in 2028/2032, 2028/2035, 2028/2039, 2030/2035, 2032/2035, 2032/2039 and 2035/2039 as well as retiring all units, or the full plant, in 2032, 2035, and 2039.

Q85. Why was the early retirement of Belle River in 2024/2025 modeled?

A85. Per the Case No. U-20471 IRP Interim Order, dated 02/20/2020, the Commission stated regarding Belle River:

> This information shall also include NPVRR analyses, with and without the environmental capital expense and operations and maintenance (O&M) costs discussed in this proceeding and in several rate cases, in order to provide the Commission with additional information on the reasonableness and prudence of planned investments, in several different proposed retirement years including 2024/2025. [P. 37]

Q86. What type of retirement analysis was completed for Belle River and Monroe?

A86. The Company compared the starting point retirement dates to several sensitivities representing different early alternative retirement dates. The team modeled the starting point and sensitivities in EnCompass. We incorporated costs associated with both continued operation of the units and earlier retirement dates, including

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ongoing O&M and capital expenditures provided by Witness Morren. In the model, if there was a capacity shortfall driven by the retirement of the units, the model optimized to fill the loss of capacity with the various resource options mentioned in Section V of my testimony, which resulted in an optimized portfolio. The team calculated the revenue requirement differences between the REF scenario starting point and all the sensitivities to rank the retirement options from most economic to least.

Q87. What resources were available to be selected in the retirement analysis?

A87. All resources described in Section V of my testimony were available in the retirement analysis optimization modeling. Based on grid reliability and transmission considerations (described in more detail by Witness Roy in his testimony) and to maintain prudent resource adequacy (described in more detail by Witness Mikulan in her testimony), when Monroe fully retires, we included a dispatchable proxy resource, approximately 1,000 MW. Therefore, in the retirement analysis, whenever Monroe was fully retired, the Company included a CCGT with CCS in the portfolio to represent a generic low or zero carbon dispatchable resource. This combined cycle resource is merely a placeholder for some future dispatchable resource that the Company will identify in future IRPs.

Q88. Were any conversion options considered in the coal unit retirement analysis?

A88. Yes, the Company evaluated converting the Belle River Power Plant from a baseload coal plant to a natural gas-fueled peaking resource.

Q89. What years were modeled in EnCompass for the Belle River gas conversion?

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A89. The Company modeled the Belle River gas conversion with a staggered approach in years 2025 and 2026. The team selected these years because the dates were in line with the Company's existing periodic maintenance schedule. In addition, the conversion accelerates the CO_2 reduction compared to the starting point of a 2028 retirement and ensures compliance with the Bottom Ash US Environmental Protection Agency Effluent Limitation Guideline (ELG) Rule, as explained further by Witnesses Morren and Marietta in their testimonies.

Q90. What inputs were used to model the Belle River gas conversion?

A90. Similar to the Belle River coal units' retirement analysis, Witness Morren also provided inputs for the gas conversion. The inputs included heat rate curves, maintenance schedules, startup parameters, and capital and O&M expenses. Witness Pratt provided inputs related to natural gas supply costs.

Q91. What were the results of the coal unit retirement and Belle River gas peaker conversion analyses?

A91. The team completed 23 runs on the REF scenario testing alternative Monroe and Belle River retirement dates and the Belle River gas conversion. See Table 3 for the results of the coal unit retirement and Belle River gas conversion analyses. We compared all cases to the starting point (REF_BASE as shown in Table 3) to derive the NPVRR variance or deltas. Table 3 displays the cases in order of economic benefit to the customer; a negative (red) value indicates the case is less expensive than the REF_BASE and a positive (black) value indicates the case is more expensive.

Table 3: IRP Retirement Analysis Results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REF_CASE_8B_BRGAS_MN28_39	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) December 31, 2039	($143)
REF_CASE_3_BLR27_MNR39	Belle River retire May 31, 2027 Monroe retire December 31, 2039	($91)
REF_CASE_10_BLR28_MNR32_39	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2032/ (1-2) December 31, 2039	($86)
REF_CASE_2A_BLR25_26_MNR39	Belle River retire May 31, 2025/26 Monroe retire December 31, 2039	($7)
REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REF_CASE_8A_BLR28_MNR28_39	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) December 31, 2039	$59
REF_CASE_7B_BLR25_26GAS_MNR28_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$88
REF_CASE_1_BLR24_25_MNR39	Belle River retire May 31, 2024/25 Monroe retire December 31, 2039	$138
REF_CASE_9A_BLR28_MNR32_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2032/ (1-2) 2035	$176
REF_CASE_9B_BLR25_26GAS_MNR32_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2032/ (1-2) 2035	$210
REF_CASE_2B_BLR25_26_GAS_MNR39	Belle River convert to gas May 31, 2025/2026 Monroe retire December 31, 2039	$246
REF_CASE_6B_BLR25_26GAS_MNR28_32	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$285
REF_CASE_5A_BLR28_MNR35	Belle River retire May 31, 2028 Monroe retire May 31, 2035	$285
REF_CASE_12_BLR25_26GAS_MNR30_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2030/ (1-2) 2035	$291

REF_CASE_7A_BLR28_MNR28_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$333
REF_CASE_11_BR28_MN30_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2030/ (1-2) 2035	$347
REF_CASE_5B_BLR25_26GAS_MNR35	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2035	$351
REF_CASE_4_BLR28_MNR32	Belle River retire May 31, 2028 Monroe retire May 31, 2032	$510
REF_CASE_6A_BLR28_MNR28_32	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$587

Q92. What was the least-cost portfolio of the coal retirement analysis?

A92. The least-cost portfolio was the REF_CASE_8B sensitivity, which included the gas conversion of Belle River in 2025/2026, Monroe units 3 and 4 retirement in 2028 and Monroe units 1 and 2 retirement in 2039. This least-cost plan had a NPVRR delta of $143 million lower cost than the REF _BASE.

Q93. Is there a retirement portfolio that is used in other scenarios and sensitivities to represent a preferred retirement plan that is not the least-cost portfolio?

A93. Yes, the Company prefers the retirement plan in the REF_CASE_7B_BLR25_26_MNR_28_35 portfolio. This portfolio includes the staggered retirement of the Monroe Power plant in 2028 and 2035. This plan also includes a Belle River conversion to a natural gas peaking resource in 2025/2026. As determined through the retirement analysis, the Belle River conversion is worth $245 million NPV (the difference between REF_CASE_7B and REF_CASE_7A shown in Table 4) and is further supported by the transmission studies as discussed by Witness Roy in his testimony and further discussed by Witness Leslie in her testimony.

Additionally, there are various reasons why the Monroe staggered retirement is preferred including:

- The Company desires to exit coal prior to 2039/2040 and the 2028 and 2035 staggered retirement with the Belle River gas conversion has the best economics comparatively with that aspiration considered
- The Biden Administration supports the exit of coal by 2035
- The 2028 and 2035 staggered Monroe Power plant retirement is similar to the retirement assumption stakeholders recommended for the STAKE scenario's starting point or base EnCompass run (described in Section VI of my testimony)
- The Belle River gas conversion helps with economics of the staggered Monroe retirement
- As explained by Witnesses Leslie and Mikulan in their testimonies, this retirement schedule is a gradual phase out of coal that maintains reliability, ensures there is enough time to build the renewable and storage resources in advance of when they are required to meet the Company's PRMR, and provides time for larger dispatchable clean resources to mature and be introduced into the market

Q94. Were there any sensitivities completed that tested the economics of the Belle River conversion?

A94. Yes, under the REF Scenario, the capital cost of the conversion was analyzed using varying costs. The preliminary estimate for the conversion was $100 million ($81 million for DTE Electric's share of the project) and three sensitivities were conducted increasing the conversion cost 30%, 50%, and 100%. The sensitivities were compared to REF_CASE_7B since it contained the preferred retirement plan. The results of the sensitivities are shown below. Even at the higher costs, the Belle River conversion remains economic when paired with a staggered Monroe retirement.

Table 4: Retirement Analysis Belle River Gas Conversion Cost Sensitivities

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REF_CASE_7B_BLR 25_26GAS_ MNR28_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$0
REF_CASE_7B_+30 BLR	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$24
REF_CASE_7B_BLR _+50	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$39
REF_CASE_7B_BLR _+100	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$79
REF_CASE_7A_BLR 28_MNR28_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$245

This table demonstrates that even with higher costs of Belle River conversion assumed, the conversion with the staggered retirement is still less expensive for customers. The NPVRR delta for the sensitivity that retires Belle River in 2028 (REF_CASE_7A_BLR28_MNR28_35) is $333M more expensive than the base and all sensitivities shown in Table 4 result in lower NPVRR deltas.

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<u>Section IX: Overview of the IRP Analysis Results</u>

<u>Pre-Inflation Reduction Act</u>

Q95. How were the various portfolios compared across each scenario?

A95. Each scenario contained several sensitivities, of which the majority resulted in differing portfolios. The NPVRR 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 ET scenario is compared against the ET scenario sensitivity portfolio with alternative retirement dates for Monroe. We ran the scenarios using a set of assumptions as the starting point. Refer to Section IV for the resources included in the starting point. The STAKE and HE scenarios were the only scenarios that assumed a different starting point as explained later in my testimony. Additionally, for any capacity shortfalls, the model optimized the remaining portfolio with the available resources discussed in Section V.

Q96. Can you describe the differences between the REF scenario and the STAKE scenario starting points?

A96. Yes. Most of the STAKE scenario starting point assumptions are the same as the REF scenario except for:

- Belle River unit 1 retirement on May 31, 2025, and unit 2 retirement on May 31, 2026
- Monroe units 3 and 4 retirement on May 31, 2028, and units 1 and 2 retirement on December 31, 2034
- 2% EWR in 2024 -2042 (refer to Witness Bilyeu on the details of this EWR level)

- Stakeholder sales and demand forecast (refer to Witness Leuker on more detail about this forecast)

Q97. Can you describe the differences between the REF scenario and the HE scenario starting points?

A97. Yes. The sales forecast is the only difference between the two scenario's starting points. The HE scenario uses the High Electrification forecast, provided by Witness Leuker, in the starting point.

Q98. What were the results of the Reference scenario sensitivities?

A98. The results are shown in Table 5. The EnCompass run results are grouped by the common sensitivity category.

Table 5: Reference Scenario Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	REF_ EWR 1.5% (2024)	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$335
	REF_ EWR 2.0%	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$947
	REF_ EWR 2.5% (2033)	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,061
	REF_ EWR 2.5%	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,623
Load & DG	REF_AGGRESSIVE_DG	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($20)
	REF_DG_FIRM_CAPACITY	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$88
Retirement	REF_CASE_7B_Peaker_Sensitivity	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$72
Renewables	REF_2022VGP_CONTRACT	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($632)

	REF_CASE_AA_PROJECT	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($429)
	REF_2022_RFP	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$84
	REF_2022_RFP_CASE_1	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$193
Transmission/ Market Purchases	REF_650MW_Cap_Purchase	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$36
DR	REF_AGGRESSIVE_DR	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$69
	REF_CARBON_DR	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$77
CO_2	REF_HIGH_CO2_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,670
	REF_HIGH_CO2_CASE_6B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$1,709
	REF_HIGH_CO2_CASE_7A	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,885
	REF_HIGH_CO2_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$2,067
Ancillary Service	REF_BASE_FULL_ANC	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$94
	REF_FULL_ANC_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$103

Q99. Are there any key observations taken from the Reference scenario sensitivities?

A99. Yes, in general the model selects a high volume of renewables and storage ranging from 4,000 to 7,000 MW of solar, 5,000 to 9,000 MW of wind, and 500 to 2,000 MW of storage over the study period. Additionally, the team noted several observations from the REF scenario sensitivities, explained below:

- EWR – When there is incremental EWR to the EWR Statewide Potential Study, the additional EWR displaces the need for solar and storage in most cases. However, the higher the energy savings level target, the more expensive the portfolio is.

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- Load & DG – The model does not select DG in the optimization, unlike utility scale solar and utility scale storage. However, when there is an assumed increase in the adoption of DG in the load forecast, there is an apparent benefit. The higher levels of DG indirectly reduce the energy and capacity demands of customers, which in turn displaces the utility-scale solar build.
- Retirement – In this sensitivity, the peakers that were identified for potential retirement through the peaker analysis process were replaced by additional DR and solar.
- Renewables – Two sensitivities focus on the potential increase in VGP demand. The added capacity in turn reduces the amount of resources needed to meet the load demand, resulting in lower costs. The other two sensitivities offer in projects based on the costs from the 2022 VGP RFP, between 2023 and 2025 into the optimization. However, the resources were not selected in the optimization.
- Transmission / Capacity Purchases – When capacity purchases were available to be selected, the purchases did offset some amounts of wind, solar and storage builds. The purchases mostly occurred in the last few years of the study period when it was most economic. When compared to REF_CASE_7B that has the same coal plant retirement schedule, the benefit is over $50 million. However, as discussed in Witness Burgdorf's testimony, there is risk relying on the capacity market due to market uncertainty and potential increases in capacity costs. While this sensitivity results in lower costs, it is based on a capacity price forecast developed by

Siemens as explained in Section VII. If capacity prices increase the benefit will diminish and could result in higher costs.

- DR – The aggressive and carbon price levels of DR from the 2021 DR Statewide Potential Study reduces the cost of the portfolios due to the lower cost of the DR programs.
- CO_2 – Higher CO_2 allowance prices increase the overall portfolio costs of the EnCompass runs completed for this sensitivity. REF_CASE_7B is the most economic when analyzing higher CO_2 costs.
- Ancillary service – As shown in Table 5, the Base and REF_CASE_7B were modeled with the ability for resources to participate in the ancillary market. The resources changed in the portfolios to slightly more solar and DR and slightly less wind, which results in portfolios around $100 million more expensive than the REF_BASE. Witness Mikulan also discusses this set of sensitivities in more detail in her testimony.

Q100. What is the least-cost portfolio of the REF scenario?

A100. The least-cost portfolio is REF_2022VGP_CONTRACT, which is $632 million less than the base, as less resources are selected in the optimization due to the increased VGP assumed in this sensitivity.

Q101. Were there any sensitivities conducted that tested different discount rates?

A101. Yes. However, solely changing the discount rate does not change the optimization as it is not a variable that impacts the model's optimization. The discount rate is used to report the stream of annual revenue requirements over the study period into its net present value. There are other financial variables such as the cost of debt and equity that impact the discount rate but also impacts the capital structure of the resources selected in the optimization. Two sensitivities were conducted, one with a lower cost of debt and equity, 3.0% and 8.0% respectively, and the other included higher assumptions 6.0% and 12.0%. Witness Cejas Goyanes's testimony describes how he derived the cost of debt and equity rates, used them in the sensitivity, and how the portfolios changed with the rate adjustments. Since the sensitivities all have different discount rates, the delta NPVRR cannot be compared. Therefore, shown in Table 6 are the total revenue requirement costs through the entire study period.

Table 6: Discount Rate Sensitivities

Theme	Sensitivity Name	Retirement Assumption	Total Rev Req (M$)
Starting Point	REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$42,346
Low Rates	REF_DISCOUNT_LOW	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$40,841
High Rates	REF_DISCOUNT_HIGH	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$42,769

Q102. What were the results of the MIRPP BAU scenario?

A102. The results of the MIRPP BAU scenario are shown below:

Table 7: MIRPP Business As Usual Scenario Sensitivity Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_BAU_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	MIRPP_BAU_EWR_OPT	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$269
	MIRPP_BAU_EWR_2.5	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,982

Load	MIRPP_BAU_CHOICE_15_2024	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($1,067)
	MIRPP_BAU_CLIMATE_CHANGE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$524
	MIRPP_BAU_50_CHOICE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,924
	MIRPP_BAU_Port4_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$7,405
Resources	MIRPP_BAU_ONLY_CTS	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,206
Retirements	MIRPP_BAU_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$563
	MIRPP_BAU_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$922
Transmission/ Market Purchases	MIRPP_BAU_CAPACITY_PURCHASE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$188
High Gas	MIRPP_BAU_HIGH_GAS_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$2,082
	MIRPP_BAU_HIGH_GAS_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$3,602
	MIRPP_BAU_HIGH_GAS_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$3,695
	MIRPP_BAU_HIGH_GAS_CASE_7B_W_SMNR	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$5,749
2019 PCA	MIRPP_BAU_2019_PCA	Belle River retire May 31, 2028/2029 Monroe retire December 31, 2039	$811

Q103. Are there any key observations taken from the MIRPP BAU scenario sensitivities?

A103. Yes, in general the model selects a high volume of renewables and storage ranging from 5,000 to 14,500 MW of solar, 0 to 9,000 MW of wind, and 1,000 to 6,000 MW of storage over the study period. Additionally, the team noted several observations from the MIRPP BAU scenario sensitivities, explained below:

- EWR – The EWR Statewide Potential Study is the most economic program as it was optimal in the sensitivity that allowed any EWR level (various levels were identified in section VI) to be selected.
- Load – In the sensitivities where the load increases, there are more resources selected to meet demand, which causes those sensitivities to be more expensive. On the other hand, in the sensitivity where the choice cap increases to 15%, the projected load forecast decreases, thus requiring fewer resources.
- Resources – The required sensitivity that only allows CTs to be selected in the capacity expansion does not result in a viable portfolio. The model selects up to 4,400 MW of CTs, however, is unable to provide energy in all hours as the EnCompass run results in unserved energy in the last years of the study period. This sensitivity also deploys existing DR programs in all hours in several years of the study period, which is unrealistic and infeasible.
- Retirement – When comparing the two retirement sensitivities, it is evident that the Belle River plant conversion from coal to natural gas provides a cost benefit. The conversion is more economic by approximately $360 million.
- Transmission/Market Purchases – Allowing market capacity purchases in the capacity expansion reduces amount of resources selected in the optimization, thus reducing the cost of this portfolio when compared to its counterpart (MIRPP_BAU_CASE_7B). As mentioned previously, reliance on the capacity market could introduce uncertainty. Capacity price increases could make the portfolio more expensive.

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- High Gas Costs - There were four sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs in all the portfolios that were evaluated under this sensitivity.

Q104. What is the least-cost portfolio of the MIRPP BAU scenario?

A104. The least-cost portfolio when compared to the base is the MIRPP_BAU_CHOICE_15_2024. This portfolio results in over $1 billion of savings, however, it assumes that the retail choice cap increases from 10% to 15%. Although, the lower demand results in fewer resources selected and reduces the overall revenue requirement for the Company, there would still be the need for additional resources given the declining reserve margins and need to maintain resource adequacy standards in Zone 7 as discussed by Witness Burgdorf in his testimony. Moreover, this portfolio assumes the choice cap would increase in 2024, but such a policy change would require an amendment to Michigan law. Because such a change in Michigan law is highly speculative, the risks associated with this portfolio are high and for purposes of the risk assessment, this sensitivity was screened out. Therefore, the MIRPP_BAU_BASE was used as the least-cost portfolio in the risk assessment as explained by Witness Mikulan in her testimony.

Q105. What were the results of the MIRPP ET scenario?

A105. The results of the MIRPP ET scenario are shown below:

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Table 8: MIRPP Emerging Tech Scenario Sensitivity Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_ET_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	MIRPP_ET_EWR_2.5	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,622
Load	MIRPP_ET_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$6,380
Retirement	MIRPP_ET_REF_CASE_8B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2039	$52
	MIRPP_ET_REF_CASE_9A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$214
	MIRPP_ET_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$341
	MIRPP_ET_CASE_11	Belle River retire May 31, 2028 Monroe retire May 31, 2030/2035	$397
	MIRPP_ET_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$399
	MIRPP_ET_CASE_6B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	$665
	MIRPP_ET_CASE_7B_SMNR	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,708
Renewables	MIRPP_ET_RENEW_25%_2030	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$406
High Gas	MIRPP_ET_HIGH_GAS_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$1,722
	MIRPP_ET_HIGH_GAS_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$2,632
	MIRPP_ET_HIGH_GAS_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$3,036

Q106. Are there any key observations taken from the MIRPP ET scenario sensitivities?

A106. Yes, in general the model selects a high volume of renewables and storage ranging from 9,000 to 17,000 MW of solar, 0 to 7,000 MW of wind, and 2,000 to 6,500 MW of storage over the study period. Additionally, the team noted several observations from the MIRPP ET scenario sensitivities, explained below:

- EWR – The 2.5% EWR program resulted in a portfolio over $1.6 billion more expensive than the base.
- Load – The load demand significantly increased in the high load sensitivity. To meet the demand, the model selected a plethora of resources including solar, storage, natural gas, demand response, CVR, wood and biomass, and municipal waste. This portfolio also included the 2.5% to 2033 EWR level.
- Retirement – Based on the results of the retirement analysis performed on the REF scenario, six of those sensitivities were included in this ET scenario. The MIRPP_ET_BASE or starting point that included the Belle River retirement in 2028 and Monroe retirement in 2039 is the least-cost portfolio of the retirement sensitivities. The SMR resource was also evaluated to understand impacts of a different clean dispatchable resource as a replacement once the Monroe Power Plant is fully retired. Including the SMR adds over $1.3 billion to the portfolio.
- Renewables – This sensitivity is very similar to the MIRPP_ET_CASE_7B as it has the same retirement plan for Monroe (2028 and 2035) along with the Belle River conversion. Both plans get to the 25 percent renewables by 2030, but this sensitivity has a slightly different portfolio towards the end of the study period that switches the timing of the solar and storage builds and because of that makes it $7 million more expensive than MIRPP_ET_CASE_7B.

- High Gas - There were three sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs in all the portfolios that were evaluated.

Q107. What is the least-cost portfolio of the MIRPP ET scenario?

A107. The least-cost portfolio is the Base. All sensitivities that were completed on the ET scenario were more expensive on a NPVRR basis.

Q108. What were the results of the MIRPP EP scenario?

A108. The results of the MIRPP EP scenario are shown below:

Table 9: MIRPP Environmental Policy Scenario Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_EP_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	MIRPP_EP_EWR_OPT	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$80
	MIRPP_EP__EWR_2.5	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$2,091
Load	MIRPP_EP_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$5,634
Retirement	MIRPP_EP_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$351
	MIRPP_EP_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$374
High Gas	MIRPP_EP_HIGH_GAS	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$408
	MIRPP_EP_HIGH_GAS_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$1,344
	MIRPP_EP_HIGH_GAS_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,610

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Q109. Are there any key observations taken from the MIRPP EP scenario sensitivities?

A109. Yes, in general the model selects a high volume of renewables and storage including 6,000 to 14,000 MW of solar, 3,000 to 9,000 MW of wind, and 2,000 to 7,000 MW of storage over the study period. Additionally, the team noted several observations from the MIRPP EP scenario sensitivities, explained below:

- EWR – The EWR Statewide Potential Study is the most economic program as it was selected in the sensitivity that allowed any EWR level (various levels were identified in section VI) to be selected.
- Load – The required sensitivity increased the load forecast substantially over the study period, driving the need for additional resources. This portfolio selected the highest amounts of solar, storage and DR amongst the other sensitivities of this scenario. In order to meet demand, the model also selected additional natural gas resources including CHP.
- Retirement – The two retirement sensitivities resulted in higher costs than the base as it required more resources to compensate for the loss in capacity and generation due to the early retirement assumption of the Monroe Power Plant.
- High Gas Costs – There were three sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs in all the portfolios that were evaluated.

Q110. What is the least-cost portfolio of the MIRPP EP scenario?

A110. The least-cost portfolio is the Base. All sensitivities that were completed on the EP scenario were more expensive on a NPVRR basis.

Q111. What were the results of the Carbon Reduction scenario?

A111. The results of the CR scenario are shown below:

Table 10: CR Scenario Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_EP_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$0
CO_2	MIRPP_CR_CO2_28%_HIGH_LOAD	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$0
	MIRPP_CR_CO2_32%_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$0

Q112. Are there any key observations taken from the CR scenario sensitivities?

A112. Yes. The CR scenario was based on the EP scenario high load sensitivity, which resulted in a 2025 carbon reduction greater than 32%. Therefore, when applying the two constraints (28% carbon reduction and 32% carbon reduction) to the EnCompass runs, the constraint did not impact the run. Therefore, the two sensitivities resulted in the same portfolios and costs remained unchanged.

Q113. What were the results of the Stakeholder scenario?

A113. The results of the Stakeholder scenario are shown in Table 11.

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Table 11: Stakeholder Scenario Results

Theme	Request	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	Starting Point	STAKE_BASE	Belle River retire May 31, 2025/2026 Monroe retire Dec 31, 2028/2034	$0
EWR	#5	STAKE_3.0_EWR	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$1,910
Load	#6	STAKE_FUEL_SWITCH	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$3,699
	#7	STAKE_25%_DG	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($149)
Resources	#2	STAKE_INC_GAS_TECH	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($517)
	#3	STAKE_LOW_RICE	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$224
Retirements	#12	STAKE_RET_BRGAS_MR28_35_CT40	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($411)
	#11	STAKE_RET_BLR25_26_MNR_28_30_H2CT	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$223
	#1	STAKE_RET_BLR25_26_MNR_28_30	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$389
CO_2	#4	STAKE_CO2_80_2030	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$223
Renewables & Storage	#8	STAKE_VGP_X2	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($787)

	#10	STAKE_COMB	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$579
	#9	STAKE_BATT_STANDARD	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$889

Q114. Are there any key observations taken from the STAKE scenario sensitivities?

A114. Yes, in general, the model selects a high volume of renewables and storage including 4,000 to 6,500 MW of solar, 8,000 to 9,500 MW of wind, and 2,500 to 5,000 MW of storage over the study period. Additionally, the team noted several observations from the STAKE scenario requested sensitivities, explained below:

- EWR – The 3% EWR level is very costly and results in the second most expensive sensitivity under the STAKE scenario.
- Load – This sensitivity is the most expensive compared to the base which is attributed to the increase in load due to the fuel switching and incorporation of the costly 3% EWR level.
- DG – With the DG growth increased to 25% by 2030 embedded in the load forecast, this reduces the volume of resources selected, resulting in lower costs than the base.
- Resources – When natural gas resources were offered into the optimization, a combined cycle was economically selected and resulted in the second least-cost portfolio. Additionally, these sets of sensitivities displayed that the RICE resource is not economic; when the capital cost of this resource was lowered, it was not selected in the optimization.
- Retirements – Sensitivities #1 and #11 are very similar, however, due to reliability concerns, Sensitivity #11 includes four hydrogen-fueled CTs as

the dispatchable replacement when Monroe Power Plant is fully retired. Including the four CTs has over $160 million in value compared to the Sensitivity #1 that does not include the four CTs. Sensitivity #12 displays both the value of the four CTs and the Belle River gas conversion; when compared to the base (which does not include the four CTs and conversion) this provides over $400 million in cost savings.

- CO_2 – When the CO_2 emissions are constrained to a minimum 80% reduction in 2030, the portfolio becomes more expensive due to the change in dispatch required to meet the reduction.
- Renewables & Storage – The battery standard this sensitivity required is costly, as the delta NPVRR results show. Additionally, Sensitivity #8 increased the amount of VGP. VGP does not impact the revenue requirement (cost to customers) although provides capacity, which reduces the amount of new resources required resulting in lower costs.

Q115. Were there other sensitivities completed on the Stakeholder scenario in addition to the ones requested?

A115. Yes. The team modeled three additional sensitivities to understand the impact of the Belle River gas conversion with earlier and later Monroe retirement dates and the impact of a carbon price on the STAKE scenario. The results of the other sensitivities are included in Table 12.

Table 12: Additional Stakeholder Scenario Results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
STAKE_RET_BLR25_26 GAS_MNR28_30	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2030	($200)
STAKE_BASE	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2035	$0
STAKE_RET_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$264
STAKE_CO2_2.50	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$1,581

Q116. Are there any key observations taken from the STAKE scenario sensitivities?

A116. Yes. There were three other sensitivities modeled on the STAKE scenario. The STAKE_RET_BLR25_26GAS_MNR28_30 is a sensitivity that results in lower costs than the Base. This sensitivity is similar to the Request #1 sensitivity as shown in Table 11, but includes the Belle River gas conversion and the CCGT w/CCS in 2030 after the retirement of Monroe which results in a benefit of $200M as shown in Table 12. In contrast, the Request #1 sensitivity results in a portfolio that is $389M more expensive than the base. When comparing these two sensitivities, the value of the firm dispatchable resource and Belle River conversion is $589M.

Next, the STAKE_RET_CASE_7B includes the dispatchable resource to replace the full Monroe Power Plant retirement. In this sensitivity, the generic low or zero carbon dispatchable resource is a CCGT with CCS. Then the last sensitivity shown in Table 12 is based on a stakeholder request. The team thought it would be appropriate to include the increased cost of CO_2 in the STAKE scenario since there was not a CO_2 price assumed. Including a carbon price forecast causes the sensitivity to be significantly more expensive due to the existing gas resources running throughout the study period.

Q117. What is the least-cost portfolio of the STAKE scenario?

A117. The least-cost portfolio when compared to the base is the STAKE_VGP_X2 sensitivity at $787 million less than the base. The added capacity in turn reduces the amount of resources needed to meet the load demand, resulting in lower costs.

Q118. What were the results of the HE scenario?

A118. The results of the HE scenario are shown below:

Table 13: High Electrification Scenario Results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	HE_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
Retirement	HE_DR	Belle River retire May 31, 2028 Monroe retire December 31, 2039	($4)
Resource	HE_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$192
	HE_CASE_7A	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$443

Q119. Are there any key observations taken from the HE scenario sensitivities?

A119. Yes. The HE scenario includes a higher level of customer demand driven by potential growth in electric vehicle sales. With the increased projected load growth, additional resources are required. In general, the model selects a high volume of renewables and storage including 6,000 to 7,000 MW of solar, 7,000 to 8,000 MW of wind, and 2,000 to 3,000 MW of storage over the study period. In addition to renewables, the model selects additional gas-fueled resources such CCGTs with CCS and CTs.

Q120. What is the least-cost portfolio of the HE scenario?

A120. The least-cost portfolio when compared to the base is the HE_DR sensitivity at $4 million less than the base due to the lower demand response costs.

Q121. Can you summarize the least-cost portfolios across the scenarios and sensitivities?

A121. Yes, the least-cost portfolios from each scenario are shown in Table 14. The CR scenario is not included as it was based on the EP scenario and did not result in different portfolio results.

Table 14: Least-cost Portfolios Per Scenario

Scenario	Sensitivity Name	Retirement Assumption
REF	REF_2022VGP_CONTRACT	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035
MIRPP BAU	MIRPP_BAU_CHOICE_15_2024	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035
MIRPP ET	MIRPP_ET_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039
MIRPP EP	MIRPP_EP_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039
HE	HE_DR	Belle River retire May 31, 2028 Monroe retire December 31, 2039
STAKE	STAKE_VGP_X2	Belle River retire May 31, 2028 Monroe retire May 31, 2028/ 2030

Q122. After the least-cost portfolios are determined, what is the next step in the IRP process?

A122. After we analyzed the EnCompass model results and identified the least-cost portfolios, the Company performed several other assessments and considered several other factors, including the planning objectives, to determine the preliminary proposed course of action. Witness Mikulan describes step 6 of the IRP process, which includes the initial synthesis of results, the other assessments considered and how the Company developed the preliminary PCA.

Q123. Was the preliminary PCA modeled through EnCompass?

A123. Yes, as described in Witness Mikulan's testimony, we modeled the preliminary PCA in EnCompass on the Reference scenario. The results of the preliminary PCA are shown in Table 15. After modeling the preliminary PCA in EnCompass, major changes in the industry led the Company to develop a new scenario, called the REFRESH.

Table 15: Results of the preliminary PCA

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REF_2022_PRELIMINARY_PCA	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$381

Post- Inflation Reduction Act

Q124. What is the purpose of the REFRESH scenario?

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A124. As explained, the Company modeled eight scenarios for this IRP and the REFRESH scenario was the last scenario that we developed. The IRP is an extensive process, spanning over many months. The team developed the initial IRP assumptions in late 2021 and then considered and evolved them through a technical stakeholder process during early 2022. To account for the known changes impacting the natural gas prices and changes to legislation, specifically, the Inflation Reduction Act of 2022 (IRA), we created the Refresh scenario and modeled it in August - September 2022.

Q125. What are the changes incorporated into the REFRESH scenario in relation to the natural gas prices and IRA?

A125. The natural gas price forecast used in the REFRESH scenario is based on forward pricing from August 2022 for years 2023 through 2027 and then transitions to the 2022 EIA natural gas price forecast for 2028 through 2042. Siemens incorporated this fuel price change into its Eastern Interconnect modeling to derive the relative impacts to the wholesale energy market price forecast. Additionally, we included aspects of the IRA relevant to the IRP to the extent the Company could appropriately account for known changes within the limited timeframe prior to filing the IRP. Given the many months of work that had already gone into the modeling for the IRP, it was not possible for the IRP team to update the inputs into the starting point and re-run all of the 100+ runs already completed in time to file this case in the fall of 2022, as DTE Electric had committed to do.[15] Thus, adding

[15] DTE October 13, 2021 Press Release https://energynow.com/2021/10/dte-energy-announces-it-will-cease-the-use-of-coal-at-belle-river-power-plant-by-december-2028-two-years-earlier-than-originally-planned/#:~:text=Detroit%2C%20Oct.%2013%2C%202021%20%28GLOBE%20NEWSWIRE%29%20%E2%80%94%20DETROIT%2C,its%20goal%20of%20achieving%20net%20zero%20carbon%20emissions accessed October 15, 2022.

a scenario including the new IRA tax credits was the best option available to the Company to study the impact of the new law, and determine what, if any, impact it would have on the PCA. More specifically, we incorporated IRA tax credit provisions impacting new solar, wind, storage, nuclear, and carbon capture and sequestration technologies into the EnCompass model. Witness Cejas Goyanes discusses the specifics of the tax credits that we accounted for in his testimony, and Witness Mikulan explains in her testimony how including this REFRESH scenario is an effective method to assess the risk of the PCA.

Q126. Were there any other changes to the modeling in the REFRESH scenario?

A126. Yes. The Company updated Belle River conversion costs to reflect the most recent estimate described in Witness Morren's testimony. Additionally, we revised the renewable constraints. For wind resources, we changed the starting year to 2028 and the maximum capacity available for the model to select to 200 MW per year. We limited solar to 400 MW per year through 2028, then increased to 800 MW between 2029 and 2034. In 2035 and beyond, the constraints are the same as all the other scenarios, up to 1,000 MW per year of either wind or solar resources. Refer to the testimony of Witness Hernandez for additional details on the renewable constraints.

Q127. Can you discuss further the rationale for including renewable energy constraints in the IRP modeling?

A127. Yes, as explained by Witness Cejas Goyanes in his testimony, the IRA tax credits provide production tax credits (PTC) for both wind and solar. With PTCs, there is an annual benefit that makes these resources more economic in the optimization and thus selected over other resources. While the optimization may produce a least-cost portfolio, results can be infeasible and unrealistic in terms of the amount and resource type of renewable energy that can actually be developed and constructed. There are various factors that led to the revision of the renewable constraints. I will address one factor as it relates directly to the capabilities in the EnCompass modeling tool. That is, the need to manage system overbuild that the model selects, also known as "superfluous build."

Q128. What is a "superfluous" build?

A128. As mentioned previously, with renewables, wind resources especially, the extended tax credits make the economics of these resources increasingly beneficial. The PTC is based on generation, and with wind resources' capacity factor exceeding 30%, the benefit of the tax credit on wind outweighs the benefit on solar. Additionally, the tax credit reduces the revenue requirement meaningfully, therefore in order for the EnCompass model to derive the least-cost portfolio, the optimization will build superfluously, meaning it will select as much of the most economic resource the model allows even when there is not a capacity shortfall. Because EnCompass does not have an option to directly limit such superfluous build, the constraints on renewable energy in the modeling optimization can help manage the selection of new resources to avoid new build driven by revenues from off-system sales in the market. A regulated utility must build and arrange adequate resources to meet the needs of its customers. This objective is fundamental to the IRP process. And given development cycles and system changes such as plant retirements, there are times when a utility may have some excess capacity and opportunities to sell that capacity into wholesale electricity markets. However, it is not appropriate to build significant amounts of new resources for the primary purpose of selling excess energy and capacity into the market based on the IRP optimization model's algorithms.

Q129. What were the results of the REFRESH scenario?

A129. The results of the REFRESH scenario are shown below:

Table 16: REFRESH Scenario Results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REFRESH_2019_PCA	Belle River retire May 31, 2029/2030 Monroe retire December 31, 2039	$4,154
REFRESH_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REFRESH_2022_PRELIMINARY_PCA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($110)
REFRESH_2022_PRELIMINARY_PCA_OPT	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($539)
REFRESH_CASE_7A_BLR28_MNR28_35	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	($620)
REFRESH_CASE_7B_BLR25_26GAS_ MNR28_35	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($705)
REFRESH_CASE_6B_PHASE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	($849)
REFRESH_CASE_6A_BLR28_MNR28_32	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2032	($941)
REFRESH_CASE_6B_BLR25_26GAS_ MNR28_32	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	($1,018)

Q130. Are there any key observations taken from the REFRESH scenario sensitivities?

A130. Yes. Overall, with the new tax provisions, all the portfolios except for the REFRESH_2019_PCA, are more economic than the base. The various sensitivities included increased levels of renewables and storage, which benefits the portfolios due to the revenue requirement savings caused by the tax credits. In general, the model selects a higher volume of renewables and storage including 6,000 to 7,000 MW of solar, 5,500 to 9,500 MW of wind, and 1,000 to 2,000 MW of storage over the study period.

The sensitivities that are shaded in gray in Table 16 include a phase in of the renewable and storage builds as explained by Witness Mikulan in her testimony. The REFRESH_2022_PRELIMINARY_PCA_OPT and REFRESH_CASE7B sensitivities are similar, but the REFRESH_CASE7B does not include the phase in. When these sensitivities are compared, there is a $166 million difference. Similarly, REFRESH_CASE6B_PHASE and REFRESH_CASE6B are alike but REFRESH_CASE6B does not include the renewables and storage phase in approach and there is a $169 million difference. Although, the phase in results in lower benefits or NPVRR deltas, also explained in Witness Mikulan's testimony, the phase in approach decreases the execution risk and increases reliability.

Additionally, as shown in REFRESH_CASE_7B_BLR25_26GAS_ MNR28_35 and REFRESH_CASE_7B_BLR25_26GAS_MNR28_35 (when compared to the CASE A counterparts), the Belle River conversion remains economic under the REFRESH scenario.

Q131. Were there any EnCompass runs completed on the REFRESH scenario that did not include renewable constraints?

A131. Yes. We completed another base sensitivity that did not include constraints on the renewables available for the model to select in the optimization. Additionally, we modeled another sensitivity similar to the REFRESH_CASE_7B_BLR25_26GAS_MNR28_35 as shown above in Table 16. The results of the two unconstrained sensitivities are shown in Table 17. The unconstrained sensitivities selected 9,100 MW of wind all in 2030, which is not feasible. Additionally, the portfolios included over 7,600 MW of solar and nearly 4,000 MW of storage. The overabundance of resources resulted in both sensitivities having significant levels of excess capacity in most years. The REFRESH_FULL_UNCON_CASE_7B is more economic than the base (unconstrained) by $455 million. However, as shown in Table 16 above, when we compared the REFRESH_CASE_7B_BLR25_26GAS_MNR28_35 to the base, it is more economic by $705 million. Consequently, constraining the renewables saved $250 million by reducing the superfluous builds.

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Table 17: REFRESH Scenario Unconstrained Results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REFRESH_FULL_UNCON_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REFRESH_FULL_UNCON_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($455)

Q132. Did the results of the REFRESH scenario change the PCA?

A132. Yes. The results of the REFRESH did change the PCA. Explained in more detail by Witness Mikulan in her testimony, the results of the REFRESH scenario were considered in the synthesis of results into the final PCA.

Q133. Was the final PCA modeled through EnCompass?

A133. Yes, we modeled the final PCA through EnCompass under all scenarios. Additionally, we included the IRA tax credits on the scenarios to understand the financial impacts. The results are displayed in Table 18. Additionally, the annual revenue requirement impact of the final PCA is detailed in Exhibit A-3.5.

Table 18 – Final PCA per Scenario

Scenario	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REF	REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	REF_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$1,264
	Results with IRA tax credits		

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	REF_BASE_IRA	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	REF_2022_PCA_FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($577)
BAU	MIRPP_BAU_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_BAU_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$2,191
	Results with IRA tax credits		
	MIRPP_BAU_BASE_IRA	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_BAU_2022_PCA_ FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($152)
ET	MIRPP_ET_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_ET_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$2,265
	Results with IRA tax credits		
	MIRPP_ET_BASE_IRA	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_ET_2022_PCA_ FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$212
EP	MIRPP_EP_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_EP_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$566
	Results with IRA tax credits		
	MIRPP_EP_BASE_IRA	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	MIRPP_EP_PCA_FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($492)
HE	HE_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	HE_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$540
	Results with IRA tax credits		
	HE_BASE_IRA	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	HE_2022_PCA_FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($977)

STAKE	STAKE_BASE	Belle River retire May 31, 2025/2026 Monroe retire May 31,2035	$0
	STAKE_2022_PCA_FINAL	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	$64
	Results with IRA tax credits		
	STAKE_BASE_IRA	Belle River retire May 31, 2025/2026 Monroe retire May 31,2035	$0
	STAKE_2022_PCA_FINAL_IRA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($1,057)
REFRESH	REFRESH_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
	REFRESH_2022_PCA_FINAL[16]	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/ 2035	($539)

Q134. What is the key takeaway from modeling the PCA across all the scenarios?

A134. The key takeaway is that the PCA is a cost-effective plan and provides costs savings to customers. Table 18 above displays the PCA with and without the tax credits. By incorporating the IRA tax credits for clean energy resources, the model was able to take advantage of the tax benefits resulting in lower costs across the portfolios.

Q135. Does this complete your direct testimony?

A135. Yes, it does

[16] Same as REFRESH_2022_PRELIMINARY_PCA_OPT included in Table 16

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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RODRIGO CEJAS GOYANES

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF RODRIGO CEJAS GOYANES

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

A1. My name is Rodrigo Cejas Goyanes (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") with the position of Supervisor – Program Management in the Integrated Resource Planning group, part of the Business Planning and Development department.

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 Buenos Aires, City of Buenos Aires, Argentina, with a degree as a Certified Public Accountant in 1992. Concurrently, I graduated with a Specialization in Taxes. In 2003, I received a Master of Business Administration with a Major in Finance and Management and Strategy from the Kellogg School of Management, Northwestern University, Evanston, Illinois.

Q4. What work experience do you have?

A4. In 2003, I joined DTE Electric as a financial consultant in the graduate development program where I was responsible for evaluating and reporting electric sales and economic forecasts, implementing the systematization of tax credit requests, and assisting in the completion of bond offerings led by the treasury department. In 2007, I accepted an internal position as Associate, and later Senior Associate, in DTE Energy's Power and Industrial group. In this role, I evaluated multiple investment opportunities in the competitive energy landscape from a financial and strategic point of view and performed budgeting and financial performance evaluation of the landfill gas and coal mine methane business units. In 2014, I accepted a Senior Associate position on the Strategy team, focusing primarily on supporting the Business Planning and Development department's testimonies in the Company's general rate cases before the Michigan Public Service Commission (MPSC or Commission). In addition, I performed long term financial feasibility of some of the Company's generation units under potential plant retirement scenarios, and concurrently, compiled and presented internal metrics and scorecard reports to senior management. In 2018, I accepted a position as Strategy and Project Specialist in the Demand Response (DR) and Energy Waste Reduction (EWR) Strategy group. With respect to DR, my responsibility centered around the strategic and financial evaluation and planning of DR programs and pilots within DTE Electric. Specifically, my role focused on evaluating the market and regulatory framework for DR and providing development, operational and financial analysis support of the existing demand response programs and future pilots. I sponsored the Company's DR programs and pilots in various regulatory proceedings.

Q5. What was your work experience before DTE Energy?

A5. I held a position as manager in the Tax Department of PricewaterhouseCoopers (PwC) from 1993 to 1998, focusing on advising businesses and individuals on tax planning, and tax matters in merger and acquisition transactions. Afterwards, I owned and managed an independent accounting service practice, advising individual clients on tax matters until 2001. I performed both roles in Buenos Aires, Argentina.

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Q6. What are your current duties and responsibilities?

A6. Since 2021, I have been working as Supervisor – Program Management in the Integrated Resource Planning group. In my current role, I lead the financial analysis and evaluation of potential resources for further consideration in IRP analysis. I work closely with the Company's internal subject matter experts to obtain and validate IRP inputs for the IRP team to use in the modeling. In addition, I interact with external stakeholders involved in ongoing and future regulatory proceedings.

Q7. Have you been involved in any prior regulatory proceedings?

A7. Yes. I have sponsored testimony and exhibits before the MPSC in the following DTE Electric cases:

Case No.	Description
U-20521	DTE Electric 2017-2018 Demand Response Reconciliation Case
U-20561	DTE Electric 2019 General Rate Case
U-20793	DTE Electric 2019 Demand Response Reconciliation Case
U-21044	DTE Electric 2020 Demand Response Reconciliation Case

In addition, I supported testimony and discovery in the following cases:

Case No.	Description
U-17767	DTE Electric 2014 General Rate Case
U-18014	DTE Electric 2016 General Rate Case
U-18255	DTE Electric 2017 General Rate Case
U-20162	DTE Electric 2018 General Rate Case

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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 2022 Integrated Resource Planning (IRP) modeling, including assumptions on the recently enacted Inflation Reduction Act
- Support the levelized cost of energy (LCOE) calculation analysis for select resources resulting in screened technologies to be considered in the IRP optimization modeling
- Support the economic analysis of selected peaker units as part of a broader analysis in which those units are considered for potential retirement, and
- Demonstrate the impact in revenue requirement calculation of the discount rate sensitivity analysis

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-4.1	Model Data Assumptions – General Detail and References
A-4.2	LCOE – Master Technology Inputs
A-4.3	LCOE – Results
A-4.4	Technologies for Consideration in EnCompass
A-4.5	Peaker Units – Economic Analysis – LCOC Results

Q10. Were these exhibits created by you or at your direction?

A10. Yes.

SECTION I: MODEL ASSUMPTIONS

Q11. The Company's IRP optimization modeling includes inputs for several different financial, cost, and operating parameter assumptions. Are you sponsoring any of the inputs used in this IRP?

A11. 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 Witnesses Mikulan and Manning, there are various steps associated with conducting the Company's IRP process. Among the eight steps listed and expanded in their testimonies, the development of the modeling inputs sponsored in this section is included as part of the step 2c.

Q12. Would you describe the financial data assumptions included in EnCompass?

A12. Yes. The financial assumptions embedded in the modeling process are detailed in Table 1 below.

Table 1. Financial Assumptions

Financial Assumptions	Case No. U-20561
Long-Term Debt	50.01%
Common Equity	49.99%
Cost of Debt (Pre-Tax)	4.22%
Cost of Equity (After-Tax)	9.90%
Marginal Cost of Capital (After-Tax)	7.06%
Marginal Cost of Capital (Pre-Tax)	8.79%

Cost of Capital for AFUDC	5.46%
Discount Rate	6.79%
Tax Rate	25.91%

The Company used the financial information and debt/equity ratios as approved in the Michigan Public Service Commission (MPSC)'s Order in DTE Electric's most recent general rate Case No. U-20561.[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).

Q13. In addition to the financial data assumptions described above, what is the general rate of inflation assumed in the IRP modeling?

A13. The IRP modeling uses a deflator series based on the Unadjusted Consumer Price Index (CPI) as publicized on October 12, 2021. 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 2023-2042 period yields 2.35%.

Q14. What are the cost and operational assumptions utilized for resources included as alternatives in the EnCompass model?

A14. Exhibit A-4.1 provides the capital and O&M cost estimates, and operating performance characteristics utilized for the various technology resources included

[1] MPSC Case No. U-20561, May 8, 2020 Order, p 177.

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in the modeling. Witness Manning further describes in her testimony how those assumptions are incorporated into the modeling.

Q15. What sources did the Company utilize as the basis for determining cost and operating parameter inputs for the various technology resources?

A15. The Company utilized three sources as primary sources to determine inputs for the various technology resources incorporated into the modeling. Two of those sources are publicly available. The first source is the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook 2021,[2] which was used as a basis for determining inputs for mostly gas-fueled and nuclear technologies. For instance, the technologies considered included combined cycle, simple cycle, combustion turbines, and small modular nuclear reactors. The second source is the National Renewable Energy Laboratory's ("NREL") 2021 Annual Technology Baseline ("ATB") report.[3] On an annual basis, NREL publishes a report of several new resource technology projected operating parameters and cost forecasts. This report includes a full narrative discussion 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. For further detail on the assumptions from the respective sources of information, EIA and NREL, refer to Exhibit A-4.1. The Company started the IRP modeling process in 2021 incorporating the latest available information in the period ranging from November 2021 through February 2022 from the NREL and EIA sources. The third source, used specifically for the new

[2] The general publicly available source EIA can be found at https://www.eia.gov/outlooks/archive/aeo21/, accessed October 21, 2022.
[3] The report is publicly available on NREL's website at https://atb.nrel.gov/electricity/2021/index, accessed October 21, 2022.

combined cycle gas turbines (CCGT) with carbon capture and sequestration (CCS), was provided by the Electric Power Research Institute (EPRI). EPRI assisted the Company to identify input assumptions for new CCGT with CCS technologies at 90% and 98.5% levels.

<u>Tax Credit Considerations Prior to the Inflation Reduction Act (IRA)</u>

Q16. What assumptions did the Company consider incorporating related to the effects of tax credits in the inputs for certain technologies?

A16. 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. The PTC is set forth in Section 45 of the Internal Revenue Code (IRC), 26 USC 45, and the ITC is set forth at Section 48 of the IRC, 26 USC 48. From late 2021 through early 2022 (i.e., prior to the passage of the Inflation Reduction Act), modeling assumptions regarding tax credits were based on the existing federal policy at the time of the modeling starting point. Under this assumption, for purposes of the EnCompass modeling, a wind resource is considered a qualified energy resource for the PTC and not for the ITC. Equipment from solar and solar plus storage resources are considered qualified energy property for the ITC.

Q17. What resource types were assumed to qualify for the PTC in the modeling prior to enactment of the IRA?

A17. The Company assumed that land based wind projects qualified for the PTC. Under the law prior to the IRA, the PTC for a taxable year was an amount equal to 1.5¢

(adjusted for inflation, approximately 2.6¢ as of 2021) multiplied by the kilowatt hours of electricity produced from qualified energy resources. The PTC was accounted for the 10-year period beginning on the date the facility is originally placed in service. As an assumption in the modeling, wind projects with in-service dates in 2023 and 2024 qualified for a reduced PTC rate, (60% of 1.5 cents), as those projects were assumed to commence construction in 2020 and/or 2021. Wind projects that start construction on or after 2021 did not qualify for any PTC.

Q18. What resource types were assumed to qualify for the ITC in the modeling prior to enactment of the IRA?

A18. The Company assumed that utility solar and solar plus storage projects, as well as commercial and residential solar projects qualified for the ITC. The ITC was equal to a certain percentage of the basis of the energy property of those projects in the year such a property is placed in service. Specifically for commercial projects, based on prior law, the ITC was assumed to be: 26% for projects commencing construction in 2020, 2021 and 2022, but placed in service before 2026; 22% for projects commencing construction in 2023, but placed in service before 2026; and 10% for projects commencing construction in 2024 or placed in service after 2025. Specifically for residential projects in the modeling, the ITC was assumed to be 22% for projects only installed in 2023. The modeling also assumed that the residential tax credit expires for projects installed after 2023.

Tax Credit Considerations After IRA

Q19. Did DTE Electric consider the recent passage of the IRA and the potential impact on the tax credits assumptions incorporated into the IRP described above?

A19. Yes. After the IRA was passed in August 2022, as discussed further below and by Witness Manning in her testimony, the Company developed a new scenario to support additional modeling runs based on the changes to the tax credits, including but not limited to the availability of a PTC for solar projects and an ITC for standalone storage, under the IRA. Until the IRA was passed, the Company's modeling assumptions were based on the existing federal policy from late 2021 through early 2022.

Q20. Can you describe the IRA and how it may differ from the prior regime of clean energy tax credit programs?

A20. Yes. As described by Witness Leslie in her testimony, the IRA was enacted into law in August 2022. It includes approximately $370 billion in funding and tax incentives for clean energy investments and climate change mitigation and adaptation. The IRA includes incentives for energy storage, renewable energy, domestic clean energy manufacturing and minerals extraction and processing, electric vehicles and charging infrastructure, building electrification, energy efficiency, hydrogen, carbon capture and sequestration, nuclear, and other clean energy investments. The IRA is expected to reduce the cost of renewable energy and other technologies that reduce greenhouse gas (GHG) emissions.

The pre-IRA regime of clean energy tax credit programs was limited to specific technologies and had been subject to continuous short-term phase outs and extensions over the last 20 years. The IRA modifies, expands, and extends the existing credits for renewable energy facilities. It allows solar generation facilities to qualify for the PTC and for standalone energy storage to qualify for the ITC. It also expands credits for carbon capture and sequestration and creates credits for nuclear production, and advanced manufacturing, among others.

Specifically, the technology-neutral IRA credits, referred to as the Clean Electricity Production Credit and the Clean Electricity Investment Credit, will apply to eligible projects placed in service after December 31, 2024, will replace the current tax credit structure for renewable energy facilities, and will only be available for renewable energy facilities with lifecycle GHG emission rates not greater than zero.

There are many open questions regarding implementation that will ultimately depend on the regulations and guidance to be issued by the Treasury department. On October 5, 2022, the IRS issued notices[4] soliciting stakeholder comment and input with respect to certain provisions of the IRA. Additional notices and guidance from the IRS are likely to follow.

Q21. Has the Company evaluated the applicability of provisions of the IRA with respect to the modeling assumptions you support?

[4] IRA implementation, See, e.g., U.S. Department of Treasury October 5, 2022 notices seeking comments on the implementation of certain provisions, such as the domestic content, energy community and low-income community designations, and transferability of credits. Available at: https://www.irs.gov/newsroom/irs-asks-for-comments-on-upcoming-energy-guidance , accessed October 21, 2022

A21. Yes. While the IRA was enacted well after the inputs, assumptions, and IRP modeling were largely completed, several energy tax credit provisions of the IRA influence the IRP modelling inputs and assumptions. Since the IRA was recently enacted, the interpretation and implementation under the federal tax code are still being defined. However, the Company has made reasonably diligent efforts to determine the extent of the applicability of the IRA to the Company's IRP modeling. From an overall perspective, Witness Leslie expands on the applicability of the provisions of the IRA supporting the Company's IRP in her testimony.

Q22. Has the Company incorporated specific tax credit provisions of the IRA?

A22. Yes. Notwithstanding timing of the IRP and considering the Company's IRP modeling process and further interpretation and implementation of the law needed and pending, the Company incorporated the extended and new tax credits (detailed below) supporting clean energy resources. These provisions are fairly clear-cut in the IRA and the Company is confident that their application in the manner applied in this IRP is reasonably reflective of future application to new projects. The Company did not however model all potential credits, as there are many provisions the application of which remain unclear or that are tied to the specific siting of projects, which is not known at this time.

Q23. How has the Company incorporated these new assumptions in the overall IRP planning process?

A23. The Company incorporated the new assumptions associated with the respective tax credits into a new scenario named Refresh (REFRESH) and its sensitivity cases. Witnesses Mikulan and Manning, in their testimonies, expand on how the Company added the updated tax credit assumptions, and on the results of the REFRESH scenario and sensitivities. By incorporating the new set of assumptions, the Company intends to include customer benefits of the additional tax credits.

Q24. What are the IRA-related tax credit assumptions considered to the Company's updated IRP modeling work?

A24. The Company followed a simplified approach in which:

1. Only one type of tax credit (either production tax credit or investment tax credit) was chosen when there are different alternatives for the same resource, for instance, selecting PTC credits for utility solar projects as they are generally more advantageous than ITC credits;
2. Only one structure (either a limited extension or new expansion) of tax credit is chosen when there are different alternatives. For instance, selecting the technology-neutral tax credits for the full modeled period of analysis versus the option of extending the existing PTC and ITC for a limited time with the applicability of the technology-neutral provision once this provision comes into effect; and
3. The most favorable timeline for tax credits is applied when there is uncertainty about the time periods for which the tax credits are applicable.

Following this approach, the Company used the following selected set of assumptions:

1. Wind Projects: Production Tax Credit (PTC) equivalent to $26/MWh from 2023 and then adjusted for inflation, for a period of 10 years from in-service date;

2. Utility Solar Projects: PTC equivalent to $26/MWh from 2023, and then adjusted for inflation, for a period of 10 years from in-service date;
3. Utility Storage Projects: Investment Tax Credit (ITC) equivalent to 30% of capital costs;
4. Distributed Generation Solar (Commercial): ITC equivalent to 30% of capital costs;
5. Distributed Generation Storage (Commercial): ITC equivalent to 30% of capital costs;
6. Distributed Generation Solar and Storage (Residential): ITC equivalent to 30% of capital costs for projects starting construction in or before 2032, and a declining percentage for projects starting construction after 2032 until 2035, after which no ITC is applicable;
7. Utility Solar Plus Storage Projects: PTC equivalent to $26/MWh from 2023 and then adjusted for inflation for solar generation equipment for a period of 10 years from in-service date, and ITC equivalent to 30% of capital costs of the storage equipment only;
8. CCGT with CCS: Specific CCS tax credit equivalent to $85 per reduced CO_2 ton in the 2023-2026 period, and then adjusted for inflation, for projects placed in service in or before 2035, for a period of 12 years from the in-service date;
9. Small Modular Nuclear Reactor: ITC equivalent to 30% of eligible capital costs; and

10. Combined Heat and Power Projects: ITC equivalent to 30% of capital costs for projects in service in or before 2025.

Q25. What additional assumptions did the Company make in assessing the overall applicability of IRA tax provisions?

A25. To assess the overall applicability of the specific tax credits, the Company assumed the following:

1. The wage and apprenticeship requirements will be met and therefore integrated into assumptions;
2. The domestic content bonus will not be available given the current uncertainty around the availability of domestically sourced components and materials and associated implementation guidance;
3. The energy community bonus credit will not be available because it is site-specific, and siting considerations are not addressed in the IRP;
4. The Company assumes that the tax credits earned under the IRA can be either used to offset DTE Electric's own tax obligations or transferred to unrelated third parties. Such transfers may not occur on a dollar-for-dollar basis, which would slightly reduce the realized benefit of the credit for the transferring tax credit owner, potentially by as much as 7%. The Company did not assume a reduction in tax credit value since 1) the Company might use the credits to offset its own tax obligations (in the future) and not transfer them, and 2) today, there is uncertainty associated with the undeveloped future tax credit markets and with the characteristics of the actual transfer arrangements. Additional guidance from the Department of Treasury will be issued on these and other provisions of the tax credits.

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The actual amount of the tax credits earned will likely vary from the modeling results, as any number of factors may differ from the assumptions used in the modeling, which will affect the final amount of the tax credits earned.

Q26. For the tax credit assumptions incorporated into the modeling, what did the Company assume for a time limit or phase out in the applicability of the tax credits created or extended by the IRA?

A26. For the projects listed in the points 1, 2, 3, 4, 5, 7, and 9 in the response to Question 24 above, the tax credits were incorporated into the modeling work under the assumption that those projects fall fully into the provisions of the Clean Electricity Production Credit and/or Investment Credit, or mostly known as the technology-neutral tax credits. For these projects under these provisions, the IRA establishes that the respective credit phases out over four years beginning on the later of either: 1) The United States Department of Energy determining that the annual GHG emission from the production of electricity in the United States is equal to less than 25% of the annual GHG emissions from the production of electricity in the United States for 2022, or 2) 2032.

Using public information[5] issued by EIA measuring CO_2 emissions, the Company estimated that the forecasted reduction in annual GHG emissions for the Electric Power Sector would not reach the 75% (100%-25%) level of year 2022 within the 20-year (2023-2042) study period of the Company's IRP. Based on this estimate, it

[5] Power sector CO_2 emissions reductions, U.S. Energy Information Administration - EIA - Independent Statistics and Analysis https://www.eia.gov/outlooks/aeo/data/browser/#/?id=17-AEO2022&region=1-0&cases=ref2022&start=2020&end=2050&f=A&linechart=ref2022-d011222a.3-17-AEO2022.1-0~ref2022-d011222a.33-17-AEO2022.1-0&map=ref2022-d011222a.4-17-AEO2022.1-0&ctype=linechart&sourcekey=0, accessed October 21, 2022.

is reasonable to assume that the phase out provision would not materialize before 2042. Therefore, due to that limited data point and the uncertainty surrounding the effective impact of the IRA in the future reduction of greenhouse gas emissions in the United States, the Company assumed that there is no phase out of the respective tax credits associated with the projects subject to the technology-neutral tax credits during the study period. The tax credit assumptions regarding the phase out provision will be revisited in future IRPs after national forecasts have been updated to reflect the implications of the IRA on the electric sector.

SECTION II: LEVELIZED COST OF ENERGY TECHNOLOGY SCREENING.

Q27. What is levelized cost of energy?

A27. The LCOE is a metric or measure expressed in $/MWh of the average net present cost of electricity generation for a generation resource over a defined time period of 15, 20, 30 or 40 years. The LCOE is calculated by forecasting the annual costs to operate a particular technology or resource over its useful life (including capital, fuel, and operations and maintenance costs), and then dividing it by that technology's forecasted generation, and then levelizing the result. The LCOE is a measure used industry-wide to compare different technologies on a consistent basis.

Q28. Are you sponsoring a LCOE calculation?

A28. Yes. I am sponsoring the calculation of the LCOE for select technologies as listed in Exhibit A-4.3.

Q29. Why are you sponsoring a LCOE calculation?

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A29. The Company performed a LCOE calculation for a group of technology alternatives that are then included in the EnCompass optimization model. The LCOE calculation is the second step in the technology screening analysis and comes after the technical feasibility screening of the emerging technology alternatives described by Witness Mikulan in her testimony. The objective of the LCOE screening process is to determine a reference point of view that guides which technologies are included in the IRP modeling work during the subsequent steps of the optimization process. As mentioned by Witnesses Manning and Mikulan in their testimonies, there are various steps associated with conducting DTE Electric's IRP process. Among the eight steps listed in their testimonies, this section of my testimony covers further details regarding steps 2c: development of supplemental model inputs and 3: development of resource alternatives.

Q30. Are there limitations in the use of the LCOE as a metric to evaluate resources or technologies?

A30. Yes. The LCOE has shortcomings as a comprehensive stand-alone evaluation tool. The LCOE is a reasonable representation of costs and generation, however it is limited to one unique project per technology with one defined start time. Also, it excludes ramping, start-up costs, dispatchability, value of capacity, and how much market value the technology is creating in alternative scenarios (e.g., energy market, capacity market). In addition, LCOE is not an appropriate metric for some technologies such as battery energy storage and demand response for which their main benefits come not from energy generation but from charging and discharging capability and peak demand reduction value, respectively.

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Q31. What are the inputs used for the LCOE calculation?

A31. The inputs used in the LCOE calculation are those used in the IRP modeling for the respective technologies as indicated in Section I above. The Company relied on publicly available sources provided by: NREL and EIA. In addition, EPRI provided the inputs for the CCS technology. DTE Electric's internal subject matter experts complemented the inputs[6] to calculate the LCOE. It is important to note that, for purposes to compare the technologies on an equal footing, the respective LCOEs were calculated for projects with a 2023 in-service date and as of 2023 values. The inputs include a set of assumptions per each technology more specifically detailed in Exhibit A-4.2.

Q32. What are the results of the LCOE analysis?

A32. The LCOE results for each technology are shown in Exhibit A-4.3

Q33. Is the LCOE analysis screening out certain technologies to be included in the IRP modeling?

A33. Yes, in a very limited way. The Company performed the LCOE calculation on a comprehensive set of technologies, for which assumptions are listed in publicly available sources. Based on the LCOE results, the Company ranked the technologies from the least to the most expensive options (i.e., lowest to highest $/MWh value) and used this information to inform the next steps in the modeling process. Almost all these technologies were included for consideration in the EnCompass optimization model. Only solid municipal waste technologies and microturbines were excluded from further consideration in the optimization

[6] DTE Electric's internal subject matter expert support was limited to using estimates for the Fermi's Extended Power Uprate and cost assumptions for the Belle River Conversion

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modeling because the resulting LCOE value represents outliers (above $300/MWh value) within the set of technology alternatives. With respect to the hydrogen fuel for generation technology, today's costs are quite uncertain. No widely used publicly available source, such as NREL and EIA, is identifying specific costs, and large scale technology applications are not mature. For purposes of the LCOE, the assumptions for this technology are based on the assumptions of combustion turbine industrial frame technology as a very generic approximation of future costs.

Q34. How were the results of the LCOE screening analysis used for in the modeling process?

A34. The results of the LCOE analysis informed the decision of the Company to include the respective technologies as resources in the EnCompass optimization modeling process. The inputs for those selected technologies are then considered inputs to the optimization modeling as described by Witness Manning. Please see Exhibit A-4.4 to see the list of those technologies screened to be evaluated in the EnCompass modeling.

Q35. Has the Company assessed whether the new tax credit provisions approved by the IRA and incorporated into REFRESH could impact the affordability of the selected resources?

A35. Yes. The Company assessed whether the application of the tax credit provisions approved by the IRA as described above could impact the affordability of the specific technology resources. This assessment, which occurred in September 2022, consisted of comparing the LCOE of the selected technology resources before and after the inclusion of the tax credits changes approved in the IRA.

Q36. What was the result of this assessment?

A36. As detailed in Table 2 below, the resulting LCOE from the application of the tax credit provisions in the IRA is lower than the LCOE calculated based on the provisions existing prior to the IRA. This resulting reduction in LCOE occurs in the technology resources selected for updates and further inclusion in the REFRESH scenario and sensitivities. This assessment was performed to validate the Company's inclusion in certain aspects of the IRP modeling the specific changes related to the clean energy tax credits approved by the IRA, even late in the modeling process and as a result of the Company's interpretation of the IRA impacts. To compare the technologies on an equal footing in Table 2 below, the respective LCOEs were calculated for projects with a 2023 in-service date and as of 2023 values. Details are also included in Exhibit A-4.3.

Table 2. Selected Resources – LCOE Prior to and After IRA

Selected Technology Resources	LCOE (Prior to IRA credits) $/MWh	LCOE (After IRA credits) $/MWh
Combined Cycle with CCS – 90% CO_2 Reduction - EIA	77.6	70.1
Combined Cycle with CCS – 90% CO_2 Reduction - EPRI	61.3	51.9
Combined Cycle with CCS – 98.5% CO_2 Reduction - EPRI	64.2	50.7
Wind	48.5	39.7
Solar	56.5	52.8

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SECTION III: ECONOMIC ANALYSIS OF PEAKER UNITS

Q37. Witness Morren discusses the Company's analysis to evaluate certain peaking units. Can you describe your role in this peaker analysis?

A37. As described by Witness Morren in his testimony, the Company has performed an analysis of certain peaking generation units within its fleet in response to the Commission's directives formulated on February 20, 2020, in its initial order in DTE Electric's 2019 IRP. As part of the analysis, my role was to perform an economic screening analysis of these peakers.

Q38. What was the objective of the economic analysis of peakers?

A38. The Company performed an analysis to economically value the units between two options: 1) retain operations versus 2) retire. Under the retire option, it may be necessary to replace the retiring units with generation, distribution, and/or other solutions in order to maintain grid reliability

Q39. What is the comparable metric used in the economic analysis?

A39. 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 $/MW 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.

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Q40. Are there limitations in the use of the LCOC to comprehensively evaluate options for peaker units?

A40. 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 Musonera describes in more detail.

Q41. What inputs were considered to complete the economic analysis?

A41. 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 Morren. For the retirement option, estimates of upgrades on the transmission and subtransmission systems as provided by the Distribution Operations (DO) team and forecasted annual capacity pricing were incorporated.

Q42. What forecasted annual capacity pricing was assumed in the economic analysis?

A42. As a capacity price assumption in the case of necessary capacity replacement for the option of retiring the units, the Company used the Reference Scenario Forecast provided by Siemens, the external third-party consultant who ran the Aurora Market Fundamentals Model for use in the IRP modeling work as discussed by Witness Manning.

Q43. What were the results of the economic analysis?

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A43. Exhibit A-4.5 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 3 below.

Table 3. Peaker Units – Economic Analysis – Recommended Options

Peaker Units	Capacity UCAP MW Planning Year (2022/2023)	Economic Screening Results Retain or Retire
Hancock 12	71.6	Retain
Northeast 12 and 13	34.8	Retain
Colfax	9.2	Retain
Placid	8.6	Retain
Putnam	9.0	Retain
Northeast 11	28.3	Retain. Excludes NE 11.1 Unit
Superior 11	34.7	Retain
St. Clair 11	13.5	Retain
Subtotal Retain	**209.7**	
Hancock 11	14.0	Retire with Upgrades. High Risk
Oliver	10.0	Retire with Upgrades. Further Evaluation
Wilmot	7.6	Retire with Upgrades. Further Evaluation
Subtotal Retire/Upgrades	**31.6**	
Fermi	18.8	Retire. No Upgrades
River Rouge	3.1	Retire. No Upgrades
Slocum	7.9	Retire. No Upgrades. Proposed for Battery Storage Pilot
St. Clair 12	3.4	Retire. No Upgrades
Subtotal Retire	**33.2**	
Total	**274.5**	

Q44. What factors does the Company take into consideration in its decision-making process regarding the retirement of generation including peakers?

A44. An economic analysis can 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. As Witness Morren indicates in direct testimony, other factors to consider include resource adequacy and grid reliability.

SECTION IV: DISCOUNT RATE SENSITIVITY

Q45. Did the Company perform a sensitivity analysis considering a different set of discount rates?

A45. Yes. Discount rate sensitivities were run to satisfy the filing requirements pursuant to Public Act (PA) 341 of 2016, section 6t, IRP Report and documentation, section XVI Proposed Course of Action.

Q46. Which discount rate sensitivities did the Company run and on what scenario?

A46. The starting point is the discount rate of 6.79% resulting from the ratios approved in the Company's Rate Case No. U-20561. Effectively, the discount rate of 6.79% is embedded in the net present value revenue requirement (NPVRR) calculation analysis of the IRP modeling process, and therefore, of the Proposed Course of Action (PCA). In order to run sensitivity options on the Reference (REF) Scenario that account for changes in the discount rate, the Company selected lower and higher values of two key variables: cost of debt and cost of equity, which both determine the discount rate at the lower and higher end of the sensitivity range. Those selected options were different enough from the starting point to drive changes in the optimization results. The determination of rates in the sensitivity range are detailed in the Table 4 below.

Table 4. Sensitivity Range – Rate Determination

Financial Assumptions	IRP Model	Lower Bound	Higher Bound
Long-Term Debt	50.01%	50.01%	50.01%
Common Equity	49.99%	49.99%	49.99%
Cost of Debt (Pre-Tax)	4.22%	3.00%[1]	6.00%[1]
Cost of Equity (After-Tax)	9.90%	8.00%[1]	12.00%[1]
Marginal Cost of Capital (After-Tax)	7.06%	5.50%[2]	9.00%[2]
Marginal Cost of Capital (Pre-Tax)	8.79%	6.90%[2]	11.10%[2]
Cost of Capital for AFUDC	5.46%	4.26%[2]	6.95%[2]
Calculated Discount Rate	6.79%	5.34%[2]	8.57%[2]
Tax Rate	25.91%	25.91%	25.91%

1. Changed Input
2. New Resulting Outcome

For the lower end of the range, changes in assumed cost of debt to 3.0% and cost of equity to 8.0% yield changes in the respective rates of cost of capital parameters and in the discount rate to 5.34%. For the higher end of the range, changes in assumed cost of debt to 6.0% and cost of equity to 12.0% yield changes in the respective rates of cost of capital parameters and in the discount rate to 8.57%. The rest of the assumed parameters, long term debt and common equity allocation, and tax rate remain unchanged.

Q47. What were the results of the discount rate analyses?

A47. Table 5 below shows the results of the analysis using different cost of debt and equity assumptions to determine the lower bound and higher bound of the discount rate sensitivity evaluation. As expected, the case in the lower bound of the sensitivity range resulted in a lower total revenue requirement of $40,841 million through the entire study period versus the total revenue requirement of $42,346 million in the REF Scenario, while the case in the higher end of the sensitivity range resulted in a total revenue requirement of $42,769, which is higher than the revenue requirement in the REF Scenario. For further information regarding these different sensitivities conducted by the Company, please refer to Witness Manning's testimony. The sensitivity case with the lower rates resulted in a build plan in which wind and storage resources were favored as opposed to solar resources. In this sensitivity case, those former resources are built even earlier than when the original REF Scenario calls for. Lower cost of debt and equity supports the investment in more efficient capital-intensive resources. On the other side of the sensitivity bound, higher cost of debt and equity disfavors those same capital-intensive investments and favors investments in more O&M-driven resources such as Demand Response (DR), and in solar resources, for which the decline in technology costs in real terms over time is more pronounced than the decline of the same costs for wind resources. This plan using higher rates pushes the development of the most disfavored resources in the outer years of the study period. The NPVRR of the sensitivity runs are not shown since all the cases have different resulting discount rates, and, therefore, the respective NPVRR values cannot be compared on an equal basis.

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Table 5. Results of Discount Rate Sensitivities

Description	Current Discount Rate	Lower Bound Sensitivity	Higher Bound Sensitivity
Resulting Discount Rate	6.79%	5.34%	8.57%
Build Plans	REF_BASE Solar: 6,200 MW Wind: 6,350 MW Storage: 1,450 MW DR: 150 MW	REF_DISCOUNT_LOW Solar: 5,600 MW Wind: 7,950 MW Storage: 1,600 MW DR: 130 MW	REF_DISCOUNT_HIGH Solar: 6,800 MW Wind: 2,000 MW Storage: 1,700 MW DR: 500 MW
Total Revenue Requirement in $M	42,346	40,841	42,769

Q48. Does this conclude your testimony?

A48. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEVIN CARDEN

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

A1. My name is Kevin Carden. My business address is 3000 Riverchase Galleria, Suite 575, Hoover, AL 35244. I currently serve as the Director of Astrapé Consulting, LLC ("Astrapé").

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company.

Q3. What is your educational background?

A3. I graduated from the University of Alabama with a Bachelor of Science in Industrial Engineering.

Q4. What work experience do you have?

A4. Prior to starting Astrapé in 2005, I was employed by Southern Company as a reliability engineer where I performed resource adequacy studies for Alabama Power, Georgia Power, Mississippi Power, and Gulf Power. In addition, I was responsible for the redevelopment, management, and use of a proprietary dispatch model used by the Southern Company for over two decades for the purposes of reliability risk and capacity valuation analysis. Further details regarding my experience may be found in my curriculum vitae, included as Exhibit A-5.0.

Q5. Do you hold any certifications or are you a member of any professional organizations?

A5. I am an active participant in several industry groups concerned with resource adequacy and reliability including the North American Electric Reliability

Corporation (NERC) Probabilistic Assessment Working Group and Institute of Electrical and Electronics Engineers (IEEE) Loss of Load Expectation Working Group.

Q6. What are your current duties and responsibilities?

A6. As the Director of Astrapé Consulting, I primarily manage the Strategic Energy and Risk Valuation Model (SERVM) software for Astrapé and perform reliability studies, capacity valuation studies, and renewable integration studies using SERVM for clients across North America and internationally. In addition to providing resource adequacy analysis for many of the largest utilities in the nation, Astrapé has performed resource adequacy analysis for many of the structured markets in North America including the Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), Pennsylvania-New Jersey-Maryland Interconnection (PJM), and Alberta Electric System Operator (AESO). Most of these entities rely on SERVM simulations for their resource adequacy assessments. I have also performed studies for Federal Energy Regulatory Commission (FERC) and the Department of Energy (DOE) on implications of market structure and reliability.

Q7. Have you been involved in any prior regulatory proceedings?

A7. I have not sponsored testimony before the Michigan Public Service Commission (MPSC) before. However, I have provided testimony to several other regulatory agencies across North America, including the Louisiana Public Service Commission, Alabama Public Service Commission, Public Utilities Commission of the State of Colorado, Indiana Utility Regulatory Commission, and the FERC.

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to explain the results of the reliability assessment, effective load carrying capability (ELCC) analysis, and flexibility assessment Astrapé Consulting performed at DTE Electric's request, to support the filing of its 2022 Integrated Resource Plan (IRP).

Q9. What is your role in conducting these analyses?

A9. I am responsible for the team conducting the analyses, and both participated directly in conducting analysis and supervised the other members of the team in conducting analysis. Throughout this testimony I will be using the terms "Astrapé" or "we" to refer to the team as a whole, or any member(s) thereof.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-5.0	Kevin Carden CV
A-5.1	2022 DTE Electric Resource Adequacy and LRZ7 ELCC Assessments

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

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Resource Adequacy, ELCC, and Flexibility Study Assessments

Q12. Can you describe the SERVM model used in the Resource Adequacy, ELCC, and Flexibility Study assessments?

A12. Yes. SERVM (Strategic Energy & Risk Valuation Model) is a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios. The SERVM model chronologically simulates the economic commitment and dispatch of a system across all pre-defined scenarios, calculating numerous economic and reliability metrics for each. This process provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under various conditions. Understanding the results of the model helps a user understand and determine the amount of reserves an electric system requires to adequately meet peak demand. The model is also used for many other analyses including ELCC studies, fuel back up studies, Equivalent Forced Outage Rate ("EFOR") improvement studies, and capacity valuations for upcoming peak seasons. SERVM also has the ability to conduct wind and solar integration studies as well as forecast production costs, energy margins, and market prices.

The major contributions to uncertainty considered in risk models such as SERVM include weather, economic forecast uncertainty, and unit performance. SERVM allows users to model future years based on historical weather patterns (typically 20 or more synthetic profiles[1]). We construct the model using historical weather to predict loads and weather sensitive resource output (i.e., renewable and hydro) under these weather conditions based on projections of future customers and resources.

[1] A synthetic profile is a hypothetical profile constructed by applying the expected relationship between weather and load in the future to historical weather patterns.

For each weather year, the model simulates five to eight points of economic load forecast error, creating hundreds of distinct scenarios. Finally, we run each scenario with dozens of random unit outage draws creating thousands of iterations as a base case simulation. These results provide a comprehensive distribution of production costs, Expected Unserved Energy ("EUE"), Loss of Load Expectation ("LOLE"), Loss of Load Hours ("LOLH"), interruptible call summaries, and other metrics used for various types of studies. We then calculate expected values of key metrics from the resulting distributions and compare the values against the target reliability standard (e.g., 1 day in 10 years LOLE) to determine the necessary reserve margin for a given system.

I will further describe how major contributions to uncertainty considered in risk models are addressed later in my testimony.

Q13. Can you describe the assumptions and framework of the Resource Adequacy assessment conducted by Astrapé Consulting?

A13. Yes. As described in detail in the 2022 DTE Electric Resource Adequacy and LRZ7 ELCC Assessments (Exhibit A-5.1), Astrapé conducted a resource adequacy assessment for MISO Local Resource Zone 7 ("LRZ") (modeling DTE Electric and non-DTE Electric load and resources dispatched within a single region). We first modeled a base case portfolio reflecting existing levels of installed capacity of renewable resources and the existing fleet of conventional resources. DTE Electric and non-DTE Electric portfolios were adjusted to meet the 2025 MISO UCAP planning reserve margin ("PRM") requirement of 7.4% UCAP capacity above the LRZ7 coincident peak load, which sets the reliability procurement obligation for load serving entities ("LSE") in that zone. A proxy unit was then added to the simulation to represent the expected reliability value of support from neighboring LRZ's as a result of load and generator outage diversity, resulting in a system at 0.1 days/yr LOLE.

Q14. Did Astrapé Consulting model proposed capacity additions and retirements for DTE Electric using the Resource Adequacy assessment described?

A14. Yes. We modeled the Preliminary Proposed Course of Action ("PCA")[2] to reflect the proposed capacity additions and retirements associated with the projected resource mixes in 2028 and 2035 and determined the subsequent reliability of the system using the SERVM model for the study year 2025. We based the capacity surplus or shortfall of the Preliminary PCA on its weighted average LOLE relative to the 1 day in 10-year standard, which is one firm load shed event every ten years (0.1 days/yr LOLE). MISO, as well as other planning entities throughout the U.S., use this standard to determine their planning reserve margin targets.

Q15. What was the major finding of the Resource Adequacy modeling conducted using the Preliminary PCA inputs?

A15. In this analysis, if we found the Preliminary PCA had a LOLE value greater than 0.1 days/yr, we added combustion turbine resources to the system with a technology class average EFOR until the system reached 0.1 days/yr. We determined the Preliminary PCA's capacity shortfall was the capacity of the additional combustion turbine resources required to reach the reliability standard. If we found the proposed build plan had a LOLE value less than 0.1 days/yr, we reduced the size of the proxy

[2] Exhibit A-5.1 refers to the Preliminary PCA as the "PCA"

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market unit until the system reached 0.1 days/yr. We determined the Preliminary PCA's capacity surplus was the amount of capacity removed.

Q16. You identified areas of uncertainty that impact LOLE. How are those addressed in modeling?

A16. Three major areas of uncertainty impact the LOLE of a system: weather effects on load and resource output, economic load forecast error, and generator performance. I will summarize how each is addressed:

1. As documented in Exhibit A-5.1, we simulated the weather effects on load by applying the past 41 years of historical temperature patterns to the current temperature and load relationship. We also used historical solar irradiance data and wind production data to develop 41 synthetic weather year solar and wind output profiles to correlate temperature, load, and variable resource output.
2. We modeled economic load forecast error with multipliers, which scaled each of the 41 load shapes up or down to reflect under-forecast or over-forecast of economic growth. We used historical economic forecast growth errors to assign probabilities to each scenario.
3. We based EFOR for DTE Electric units on historical operation, while we based EFOR values for non-DTE Electric units on generic resource class average values. Astrapé used SERVM to simulate the commitment and dispatch of resources to load on an hourly basis to determine capacity shortfalls.

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We simulated the model thousands of times to capture a wide range of combinations of weather conditions, economic load forecast error, and unit performance issues. We probability-weighted the LOLE results from the model across the scenarios. We gave each weather year and Monte Carlo unit outage draw equal probability, while giving each load forecast multiplier a different probability, as discussed in Exhibit A-5.1, p 16.

We performed an additional sensitivity to determine the capacity surplus/shortfall of the Preliminary PCA by placing unique probability weightings across the 41 weather years. These probabilities had an increased weighting for hotter weather years relative to colder weather years to capture the trend in increasing historical temperatures.

Q17. What was the determined capacity surplus/shortfall of the Preliminary PCA in the analysis performed by Astrapé?

A17. Astrapé found the 2028 and 2035 Preliminary PCA to have 308 MW and 403 MW of surplus capacity, respectively, assuming equally weighted historical weather years. Applying the projected future climate weather year probability weightings, we found the 2028 and 2035 Preliminary PCA to have 268 MW and 360 MW of surplus capacity respectively.

Q18. Are there differences between the Preliminary PCA portfolios analyzed by Astrapé and the Final PCA presented in DTE Electric's IRP?

A18. Yes. There are 100 MW of additional wind in 2028 in the Final PCA portfolio compared to the Preliminary PCA portfolio analyzed by Astrapé. Similarly, there

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is additional solar, wind, and storage in the 2035 Final PCA of 1,153 MW, 1,172 MW, and 1,200 MW ICAP respectively, as discussed by Witness Mikulan in her testimony. While the marginal ELCC of wind, solar, and storage decline as penetration increases, the addition of any generation capacity will provide positive reliability value. Therefore, these additions will further improve the reliability of the Final PCA portfolio and increase its expected capacity surplus.

Q19. What are ELCC values and how are they used?

A19. The ELCC of a renewable/intermittent resource is the capacity value (expressed in MW) associated with the resource's reliability contribution to the system. ELCC values are used to quantify the perfectly available capacity equivalent of an intermittent or energy limited resource, similar to how conventional resources are derated by their EFORd in order to determine their unforced capacity ("UCAP") rating.

Q20. Can you describe the assumptions and framework of the ELCC assessment conducted by Astrapé Consulting?

A20. Yes. As discussed in detail in the 2022 DTE Electric Resource Adequacy and LRZ7 ELCC Assessments (Exhibit A-5.1), Astrapé conducted an effective load carrying capability assessment for the MISO LRZ7 to determine the reliability contribution of solar, wind and battery storage resources that DTE Electric Company may procure as part of its resource planning.

Q21. How did Astrapé calculate ELCCs?

A21. Astrapé calculated the ELCC values using the SERVM model of MISO LRZ7 loads and resources. We developed a base system for study year 2025 and simulated across 41 weather years (1980-2020), 5 points of load forecast error, and 30 random unit outage draws and tuned to meet the reliability standard of 0.1 days/yr LOLE. We then calculated the ELCC values for various portfolios of solar, wind, and battery storage at different system penetration levels using the following steps:

1. We added a given amount of installed capacity of solar, wind, and battery storage resources to the system and determined the resulting reduction in LOLE (simulated across all 41 weather years, 5 load forecast errors, and 30 unit-outage draws).
2. We iteratively added flat blocks of load to the system until the LOLE reached the base case value of 0.1 days/yr.
3. The resulting MW value of load necessary to reach the base case LOLE value is the ELCC of the solar, wind, and battery storage portfolio we added to the system in step two.
4. We repeated steps 1-3 for several combinations of solar, wind, and battery installed capacity amounts to develop ELCC trends as a function of resource system penetration.

Q22. What are the key findings of the ELCC assessment?

A22. Astrapé found the reliability contribution, as measured by ELCC, of batteries, solar photovoltaic ("PV"), and wind plants to decline as the penetration of each technology increases. Synergies among technologies – primarily between batteries

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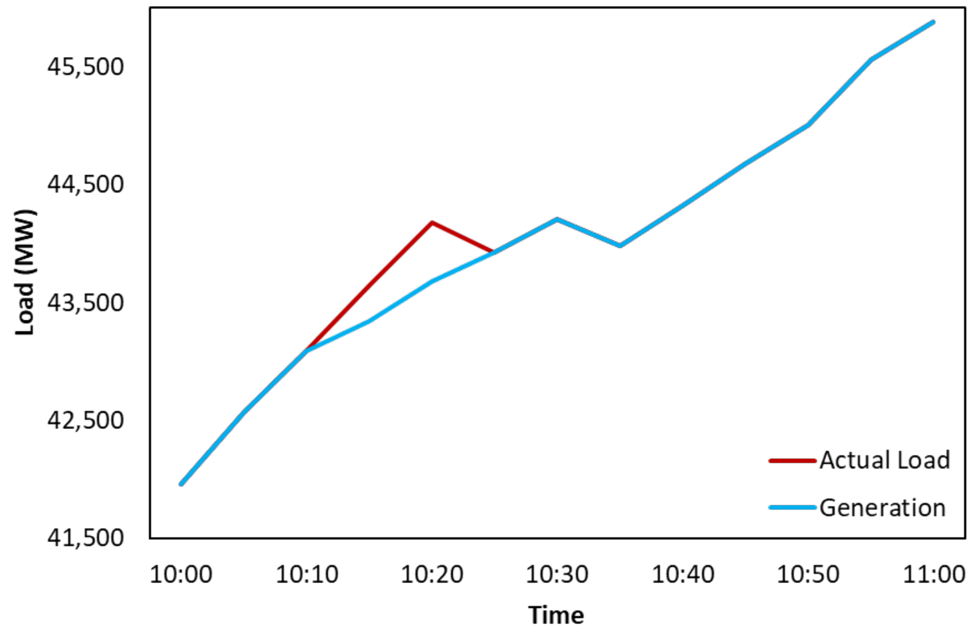
and solar – provided more reliability for the combined portfolios than implied by analysis of the technologies in isolation. We quantified the synergies into a series of curves to demonstrate the ELCC of each technology as a function of the penetration of all three technologies. ELCC curves for individual technologies and total portfolio ELCC values are described in detail in Exhibit A-5.1. We formatted the data into a calculator tool that allowed users to determine the ELCC allocated to specific resource technology classes when inputting battery storage and solar penetration levels. Witness Mikulan presents ELCC curves using output data from the calculator tool in her testimony.

Q23. Can you describe Flexibility Violations?

A23. The use of non-dispatchable renewable resources such as wind and solar in the bulk electric system results in an increase in volatility of energy produced throughout the day, creating a need for a flexible system that can respond to sharp changes in the net load profile. The SERVM model has the capability of simulating intra-hour studies (5-minute time intervals) to capture Flexibility Violations. Flexibility Violations are the expected number of days per year with a modeled imbalance between load and generation due to ramping constraints or required generator start up times (as opposed to loss of load due to a lack of system capacity).

Figure 1 shows an example of Flexibility Violations due to renewable output volatility and intra-hour ramping constraints. These events are typically very short in duration and are caused by a rapid decline in solar or wind resources over a short time interval. Increasing online spinning reserves or adding fast ramping capability resources can help resolve these issues.

Figure 1. Intra-Hour Flexibility Violations Example



Q24. Can you describe the assumptions and framework of the Flexibility Study assessment conducted by Astrapé Consulting?

A24. Yes. We modeled a base case for LRZ7 with existing levels of renewable resource penetration and quantified the intra-hour flexibility violations. The base case was similar to the base case developed for the resource adequacy assessment, with the market proxy unit replaced with generic combustion turbine resources. We modeled four alternate LRZ7 portfolios with varying amounts of renewable resource additions incremental to the base case: 4GW of incremental solar, 8GW of incremental solar, 14GW of incremental solar, and 2GW of incremental wind. The increase in renewable resources resulted in an increase in intra-hour flexibility violations, without any additional adjustments to the ancillary services requirements (i.e., unmitigated portfolios). We then iteratively adjusted load following reserve requirements until the flexibility of the system reached its base case value (i.e., mitigated portfolios). The total production cost difference between the unmitigated and mitigated simulations therefore reflected the renewable integration cost, which we calculated for all four incremental renewable penetration levels.

Due to the quick dispatch response of battery resources, systems with greater amounts of installed battery storage capacity are more flexible and are able to mitigate the increase in flexibility violations associated with increased renewable resources at a lower cost. To quantify this flexibility benefit, we simulated the four incremental renewable penetration levels with an assumed amount of battery storage capacity and calculated the total production cost difference between the unmitigated and mitigated simulations. We calculated the flexibility benefit attributed to batteries by comparing the delta between the unmitigated and mitigated case with and without battery storage.

Q25. What are the key findings of the Flexibility Study?

A25. Our analysis demonstrates an increased penetration of renewable resources drives the need to carry more operating reserves or to add more flexible dispatchable capacity. While the flexibility needs can be addressed by the existing portfolio by simply raising operating reserve targets,[3] a more flexible portfolio with quicker ramping capabilities can integrate larger renewable portfolios more economically from a variable cost standpoint. This value is an incremental benefit that accrues to

[3] Increasing operating reserve targets means increasing the minimum required amount of units online, not supplying power to the grid to meet load, but standing by available to respond quickly to imbalances between generation and load. Increasing operating reserve targets necessarily increases costs.

flexible resources such as battery storage above the value quantified in hourly production cost simulations.

The four incremental renewable penetrations we analyzed were: 4GW Solar, 8GW Solar, 14GW Solar, and 2GW Wind. Solving the flexibility shortfalls by carrying more load following reserves becomes more expensive as renewable capacity increases as shown in Tables 1 and 2. Load following reserves are provided to the system as a result of committing more units and dispatching these units below their maximum capacities such that they can respond to rapid changes in the net load by ramping up their output.

Table 1: Average Load Following Need Impact (MW)

	Average Load Following Need Impact (MW)	
	No Battery	With Battery
4000MW Solar	230	74
8000MW Solar	614	0
14000MW Solar	1,017	0
2000MW Wind	235	84

Table 2: Integration Cost ($/MWh)

	Integration Cost ($/MWh)		
	No Battery	With Battery	Delta
4000MW Solar	$ 1.82	$ 0.09	$ 1.73
8000MW Solar	$ 2.64	$ 0	$ 2.64
14000MW Solar	$ 2.96	$ 0	$ 2.96
2000MW Wind	$ 2.28	$ 0.22	$ 2.07

Witness Mikulan presents how these results were used in her testimony.

Q26. Does this complete your direct 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, and for other relief)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JUSTIN L. MORREN

Line No.

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

A1. My name is Justin L. Morren (he/him/his). My business address is 4400 River Road, East China MI, 48054. I am employed by DTE Electric Company, a subsidiary of DTE Energy.

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 Mechanical Engineering from Pennsylvania State University. I have also completed several Company sponsored courses and have attended various seminars to further my professional development with DTE Electric.

Q4. Please summarize your professional experience.

A4. From 1987 to 1993, I worked for the Department of Defense at the Philadelphia Naval Shipyard. I performed the role of mechanical engineer focusing on the area of steam propulsion, primarily on non-nuclear aircraft carriers.

From 1993 to 2004, I worked for Lukens Steel Co. (Bethlehem Steel Co, International Steel Co.) where I held various engineering and leadership roles specifically in various Maintenance Departments.

I began my employment with DTE Energy in July 2004 as the Continuous Improvement Expert at the Greenwood Energy Center and received various

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promotions with increasing levels of responsibility. These positions included Maintenance Manager for the St. Clair Power Plant in December 2005. In 2008, I was promoted to Plant Manager, North Area Plants, responsible for all day-to-day operation, maintenance, and engineering for the Greenwood Energy Center, Harbor Beach Power Plant, and Marysville Power Plant, including the decommissioning of the Marysville facility. In May 2011, I was appointed Plant Manager of the Belle River Power Plant. In this position, I was responsible for the day-to-day operation, maintenance, and engineering of the power plant. In August 2014, I was promoted to Director North Area Fossil Plants for DTE Electric. In this capacity, I was responsible for all day-to-day operation, maintenance, and engineering associated with Belle River Power Plant, St. Clair Power Plant, Greenwood Energy Center, and Peakers. I was also responsible for DTE Electric's interest in the Ludington Pumped Storage facility. I was also a voting member of the Capital Governance Board (CGB) that is responsible for approving the allocation of capital funds among the fossil generation units.

In April 2019, I transitioned from a role as North Area Director to a Plant Director of Fossil Generation. That position involved fleet-wide responsibilities for asset maintenance planning and execution, strategic planning, reliability performance, workforce planning, and operations of the new Blue Water Energy Center (BWEC). I also continued my responsibilities for approving capital projects as a voting member of the Capital Governance Board.

Q5. What is your current position with the Company and what are your current responsibilities?

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A5. In July 2021, the Company restructured some of its business units and combined Renewables Operations with the Fossil Generation business unit into a new integrated business unit called Energy Supply. With this change, I was appointed to Energy Supply Gas Plant Director and my responsibilities now include the leadership of Blue Water Energy Center, Greenwood Energy Center, Peaker Operations, and Ludington Pumped Storage Plant (DTE Electric's share).

Q6. Have you previously provided testimony before the Michigan Public Service Commission (Commission)?

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

U-20561	2019 DTE Electric General Rate Case
U-20836	2022 DTE Electric General Rate Case

<u>Purpose of Testimony</u>

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 2022 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 changes to the coal-fired retirement schedule that are included in the Company's Planned Course of Action (PCA).
- The Operation and Maintenance (O&M) expenses and capital expenditures planned for Belle River and Monroe Power Plants under various retirement sensitivities analyzed in this IRP, which is discussed by Company Witness Manning.
- A summary of the scope, schedule, cost, and benefits associated with converting Belle River Power Plant from coal-fired to natural gas-fired operation, a project for which the Company requests pre-approval in this IRP filing.
- A summary of the peaker analysis presented in this IRP, along with O&M expenses and capital expenditures supporting the economic portion of the analysis.
- The characteristics of an energy storage asset currently under development, the 14 MW Slocum Battery Energy Storage System (BESS), and future energy storage build included in the Company's PCA.

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Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes, I am sponsoring the following exhibits:

Exhibit	**Description**
A-6	O&M and Capital Expenditures – Belle River Power Plant
A-6.1	O&M and Capital Expenditures – Monroe Power Plant
A-6.2	Belle River Power Plant Projected Operating Characteristics
A-6.3	NDA Belle River B&W EPC Technical Specifications
A-6.4	NDA Belle River B&W Budget Proposal
A-6.5	Belle River Power Plant Natural Gas Conversion Cost
A-6.6	Belle River Power Plant Natural Gas Conversion Timeline
A-6.7	Belle River Power Plant Natural Gas Conversion BOD Approval
A-6.8	Belle River Power Plant Socioeconomic Impact Report
A-6.9	O&M and Capital 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 six (6) sections:

Section I	Characteristics of Dispatchable Generation Resources
Section II	Coal-fired Generation Retirement Schedule
Section III	Belle River and Monroe Power Plant Projected O&M Expenses and Capital Expenditures
Section IV	Belle River Power Plant Natural Gas Conversion Project Scope, Cost, and Schedule

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Request for Pre-approval of Belle River Natural Gas Conversion

Benefits of a Belle River Power Plant Natural Gas Conversion

Section V Peaker Analysis

Section VI Battery Energy Storage System Pilot Project and Future Build

SECTION I – CHARACTERISTICS OF DISPATCHABLE GENERATION RESOURCES

Q11. Can you describe the existing DTE Electric fossil fueled, nuclear, peaking, and pumped storage hydro generating fleet?

A11. DTE Electric currently owns and operates two (2) coal-fired steam power plants (Monroe and co-owner of Belle River), one natural gas-fired combined cycle power plant (Blue Water Energy Center), one natural gas-fired steam power plant (Greenwood), one nuclear power plant (Fermi 2), is a co-owner of a six (6) unit pumped storage hydraulic power plant (Ludington), one natural gas-fired combined heat and power plant (Dearborn CHP), and is also the owner and operator of 82 gas and oil-fueled peaker units located in the lower peninsula of Michigan.

Table 1 contains a summary of the characteristics of the existing fossil-fueled, nuclear, and pumped storage generating units.

Table 1 – Current Generating Units (Non-Renewable)

Plant	Location	Commercial Operation Date	Summer Capacity (Net MW)	Primary Fuel	Emissions Control	Co-Owned?
Belle River	East China Twp, China Twp	1984-5	1,270 (1,034 DTE Electric, 81.39%)	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	1,127	Natural Gas	Multi-pollutant catalyst, SCR[7], low NOx[1] turbines	No
Dearborn Combined Heat and Power	Dearborn	2019	34	Natural Gas	Low-NOx[1] turbines	No
Fermi 2	Frenchtown Twp	1988	1,141	Nuclear	Non-carbon emitting	No
Greenwood	Avoca Twp	1979	785	Natural Gas	Low NOx[1] burners, OFA[2]	No
Ludington Pumped Storage	Ludington	1973	1,122 (DTE Electric, 49%)	Hydro	Non-emitting	Consumers Energy, 51%
Monroe	Monroe	1971-4	3,066	Coal	Low NOx[1] burners, OFA[2], ESP[3], FGD[6], SCR[7]	No
Peaker fleet	Various	Various	1,998	Oil, Natural Gas	Low-NOx[1] turbines, oxidation catalysts	No

Acronyms: 1 – Nitrogen Oxide, 2 – Over Fire Air, 3 – Electro-static Precipitators, 4 – Dry Sorbent Injection, 5 – Activated Carbon Injection, 6 – Flue Gas Desulfurization, 7 – Selective Catalytic Reduction

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Further details can be found in Section 7 of the IRP Report (Exhibit A-3.1) sponsored by Witness Manning.

SECTION II – COAL-FIRED GENERATION RETIREMENT SCHEDULE

Q12. How has the Company modified its generation fleet since 2014?

A12. Between 2014 and 2022, the Company retired 2,698 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). This substantially reduces the Company's reliance on coal-fired generation and leaves only two Company coal-fired power plants in operation— Belle River Power Plant (1,270 MW) and Monroe Power Plant (3,066 MW).

Q13. As part of this IRP, did the Company analyze retirement dates for both the Belle River and Monroe Power Plants?

A13. Yes. As described by Company Witness Manning, DTE Electric analyzed several retirement timetables. For Belle River Power Plant, the Company analyzed retirements in 2028, 2027, 2025/2026, 2024/2025, and a conversion from coal-fired to natural gas-fired operations in 2025/2026. For Monroe Power Plant, the Company analyzed staggered unit retirements in 2039, 2035, 2032, 2030, and 2028 and full retirement in 2039, 2035 and 2032.

Q14. Based on the outcome of the IRP analysis in this proceeding, how do the Company's plans for the retirement of coal-fired operations at Belle River Power Plant and Monroe Power Plant change from the dates reflected in the Company's last (2019) IRP?

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A14. The Company has proposed to accelerate retirement of coal-fired operations at both plants. In the 2019 IRP, the Company planned to retire Belle River Power Plant and Monroe Power Plant in 2029/2030 and by 2040, respectively. In October of 2021, DTE Electric accelerated the date to cease the use of coal as a fuel source to 2028 at Belle River Power Plant. This updated timeline aligned compliance plans with the United States Environmental Protection Agency's (EPA) Effluent Limitation Guideline (ELG) rules. The power plant retirement dates in this filing's PCA described by Witness Mikulan include accelerating the retirement of coal-fired operations at Belle River Power Plant from 2028 to 2025/2026 with a natural gas conversion and accelerating the retirement of Monroe Power Plant Units 3 and 4 from 2039 to 2028 and Monroe Units 1 and 2 from 2039 to 2035.

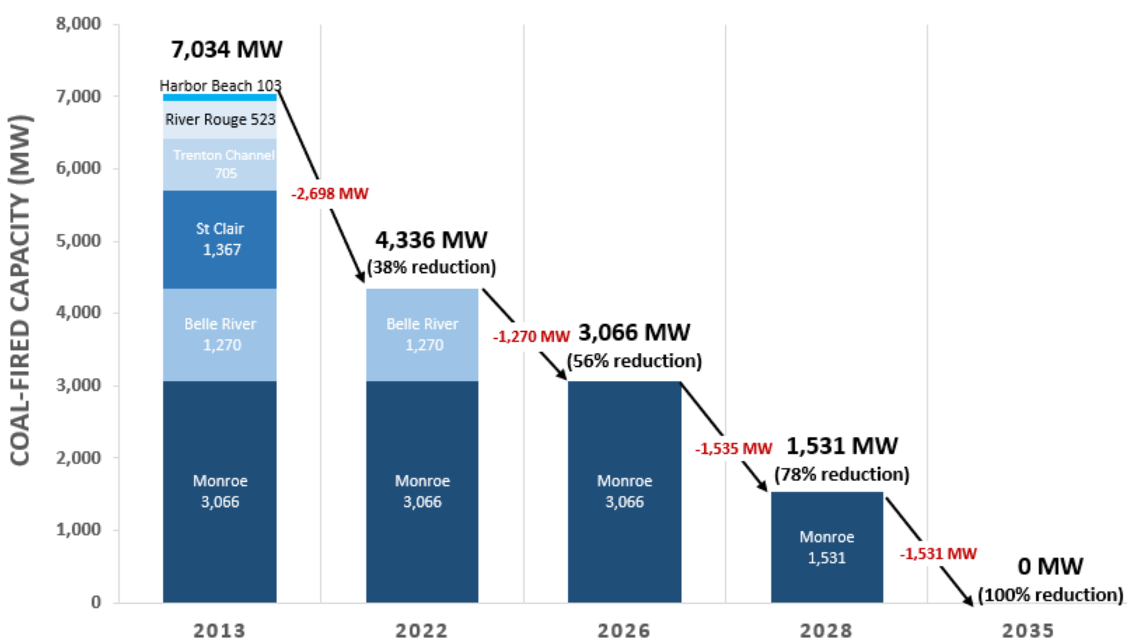
Q15. Is the conversion of Belle River Power Plant to natural gas and the accelerated retirement of Monroe Power Plant interrelated?

A15. Yes. Ceasing coal-fired operations at Belle River Power Plant and converting the plant to gas-fired operations retains 1,270 MWs of existing MISO Zone 7 capacity and paves the way for the early retirement of 1,535 MWs, or half of Monroe Power Plant, in 2028. Retention of Belle River Power Plant's capacity is critical to maintaining bulk electric grid capacity levels that allow for the early retirement of two units at Monroe in 2028 and is economically favorable as discussed by Company Witnesses Mikulan and Manning.

Q16. How does the proposed PCA in this proceeding advance the retirement dates of the Company's coal-fired power plants?

A16. As shown in Figure 1 below, the Company retired 2,698 MW of coal-fired capacity between 2014 and 2022 by completing the retirements of Harbor Beach, River Rouge, St. Clair, and Trenton Channel Power Plants. The proposed plan to convert Belle River Power Plant to gas-fired operations by the end of 2026 and retire half of Monroe Power Plant in 2028 will retire an additional 2,805 MW of coal-fired capacity. In total, this equates to the retirement of 5,503 MW of coal-fired capacity between 2014 and 2028. This will leave only 1,531 MW of coal-fired capacity (Monroe Power Plant Units 1 and 2) after 2028 in the DTE Electric system that had 7,034 MW of coal-fired capacity just nine years ago, or a near 80% reduction in coal-fired capacity.

Figure 1 – Company Coal-fired Operations



As a result of the accelerated phase out of coal, and as further discussed by Witness Leslie, the Company is expected to reach a 65% reduction in annual CO_2 emissions as compared to 2005 levels when Belle River Power Plant is converted to a natural gas peaking resource and half of Monroe Power Plant is no longer operating, and an 85% reduction in annual CO_2 emissions as compared to 2005 levels when all coal-fired units are retired.

SECTION III – BELLE RIVER AND MONROE POWER PLANT PROJECTED O&M EXPENSES AND CAPITAL EXPENDITURES

Q17. Can you describe the information shown in Exhibits A-6 and A-6.1?

A17. Exhibits A-6 and A-6.1 show the forecasted annual O&M and capital expenditures planned respectively for the Belle River Power Plant and Monroe Power Plant retirement sensitivities being analyzed in this case. 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.

Q18. How were the base O&M expenses in Exhibits A-6 and A-6.1 developed?

A18. Base O&M values utilized data from the latest full year that actual values were available (2020) at the time the forecasts were developed as the starting point. The 2020 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 a governmental Consumer Price Index (CPI) utilizing 2020 as the base year. The use of this inflation mechanism is consistent with the IRP modeling process and is more fully described by Witness Cejas Goyanes in his testimony.

Q19. How are Monroe Power Plant and Belle River Power Plant base O&M expense forecasts modified when staggered unit retirements are considered?

A19. In sensitivities in which half of the units at a plant retire in a 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. During the year in which half of the plant retires partway through the year (May), the Company assumes a 15% reduction for that single year to represent the base O&M transitioning from no reduction in the year prior to a 30% reduction in the next year. 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.

Q20. How is base O&M expense modified for unit retirements in your forecasts?

A20. In sensitivities in which the plants retire part-way through the year (May), the base O&M expense is reduced by 25% in the year the unit is retired and is then reduced by 90% for the next five years. The 25% year-1 reduction forecast is based on the unit retiring in May of that year and the need to both initiate make-safe activities during the remainder of the year and transition employees to other jobs and sites. Make-safe activities include removal of hazardous materials and shutdown of electrical, mechanical, plant controls, water and gas service and disconnection from the transmission system. The 90% reduced O&M expense forecasts in years two through six are based on retaining a small work force to sustain operations of National Pollutant Discharge Elimination System (NPDES) environmental control equipment and to provide general support for the initiation of site cleanup, equipment removal and demolition activities. After the sixth year following its retirement, the plant's O&M is assumed to be reduced to zero.

In sensitivities in which the plants retire at the end of the year (December), the base O&M expense forecast is reduced by 50% in the year following retirement and is then reduced by 90% for each of the next five years. The 50% year-1 reduction is based on the unit retiring in December of the prior year and the need to both initiate make-safe activities the following year and transition employees to other jobs and sites. Make-safe activities include removal of hazardous materials and shutdown of electrical, mechanical, plant controls, water and gas service, and disconnection from the transmission system. The 90% reduction in O&M expenses in years two through six are based on the need to retain a small work force to sustain operations of NPDES environmental control equipment and to provide general support for the initiation of site cleanup, equipment removal and demolition activities. After the sixth year following its retirement, the unit's O&M forecast is reduced to zero.

Q21. How were the major maintenance O&M expense and capital expenditure forecasts for Exhibits A-6 and A-6.1 developed?

A21. The major maintenance O&M expense and capital expenditure forecasts were developed based on a long-term maintenance schedule that considers the timing and duration of future planned major maintenance outages for each unit. 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.

Q22. Can you explain the balance of plant capital expenditures forecasts included in Exhibits A-6 and A-6.1?

A22. The balance of plant capital expenditure forecasts in Exhibits A-6 and A-6.1 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.

Q23. Can you describe the major environmental capital expenditure forecasts contained in Exhibits A-6 and A-6.1?

A23. The major environmental capital project forecasts shown in Exhibit A-6 are for Belle River Power Plant. The expenditures represent closure costs for the bottom ash basin, diversion basin, and Range Road Landfill. There are no Effluent Limitation Guidelines (ELG) environmental capital costs shown for any of the Belle River Power Plant retirement dates because of the Company's decision to cease the use of coal by 2028. Exhibit A-6.1 includes projects to comply with ELG Rules, Coal Combustion Residual (CCR) Rules, and 316(b) Cooling Water Intake Structures Rules for Monroe Power Plant. Company Witness Marietta describes these rules, regulations, and compliance dates in detail and their current evolving status.

Q24. Can you summarize the total major environmental capital expenditure forecasts projected in the Company's PCA?

A24. The total major environmental capital expenditures projected in the Company's PCA are summarized in the following table:

Table 2: PCA Major Environmental Capital Expenditures (2023-2042) ($ million)

Regulation	Belle River Power Plant	Monroe Power Plant
ELG	$0	$221[1]
CCR	$34[2]	$310[3]
316(b)	$0	$57

1. Fly Ash ($37 million), Bottom Ash ($78 million), and FGD Wastewater ($106 million).
2. Bottom Ash Basin Closure ($20 million) and Range Road Closure ($14 million).
3. Bottom Ash Basin Closure ($49 million), Fly Ash Basin Closure ($201 million), Vertical Extension Closure ($27 million), and Sibley Quarry Upgrades and Closure ($33 million).

Q25. How did the accelerated elimination of operations on coal at the Belle River Power Plant impact the values included above in Table 2?

A25. By ceasing coal-fired operation at Belle River Power Plant by the end of 2028, the Company, and its customers, avoid installing a new bottom ash transport system estimated to cost $55 million.

Q26. How does an accelerated retirement of the Monroe Power Plant Units 3 and 4 impact the values included above in Table 2?

A26. By retiring Monroe 3 and 4 by the end of 2028, the Company and its customers avoid installing new ELG-compliant FGD wastewater systems estimated to cost

$21 million. Additionally, the accelerated retirement of Monroe 3 and 4 could reduce potential investment for attaining 316(b) compliance by an estimated $24 million.

Q27. What overall O&M and capital reductions would the Company expect associated with accelerating all of the Monroe Power Plant unit retirements?

A27. By accelerating the retirement of Monroe Units 1-4 from 2039 to Units 3 and 4 in 2028 and Units 1 and 2 in 2035, the Company expects to reduce total Monroe Power Plant O&M expense by $1.3 billion and capital expenditures by $0.9 billion over the 2022-2045 timeframe.

Q28. What impact to future O&M and capital expenditures at Belle River Power Plant (DTE Electric and MPPA) does the Company expect when transitioning from coal-fired to natural gas-fired in 2025/2026?

A28. Operating on natural gas, the Company expects lower ongoing costs at the plant. As shown in exhibit A-6, Belle River Power Plant annual O&M expenses are expected to average $22 million and annual capital expenditures to average $8 million from 2027 to 2039 after the conversion of Belle River to operate on natural gas. This compares favorably to 2017-2021 actual annual O&M expense of $50 million and actual annual average capital expenditures of $36 million at Belle River, even excluding the time value of money.

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SECTION IV – BELLE RIVER POWER PLANT NATURAL GAS CONVERSION

Project Scope, Cost, and Schedule

Q29. What is the Belle River Power Plant natural gas conversion project?

A29. The Belle River Power Plant natural gas conversion project allows the Belle River Units 1 and 2 main unit boilers to be fueled with natural gas instead of coal and oil. The physical conversion is a minor, low-cost, and expeditious alteration to the power plant that also maintains the electrical output capabilities of the existing generating units. Converting the Belle River Power Plant to operate on natural gas not only is forecasted to reduce emissions as shown later in Table 3, but also retains the plant's electrical output that is needed as a critical reliability resource in an important area of the grid in southeast Michigan as explained by Company Witness Burgdorf.

Q30. Would Belle River plant utilization change upon conversion to natural gas?

A30. Yes. Upon conversion to natural gas, Belle River Power Plant is expected to operate as a cycling plant, similar to the Company's Greenwood Power Plant Unit 1, with a forecasted capacity factor around 10%. The plant will no longer be operated as a base-loaded power plant. The capacity factor will be far lower than was experienced while operating on coal but the generating capability of Belle River Units 1 and 2 is not forecasted to change with the fuel conversion. As Witness Leslie describes, the converted Belle River Power Plant will be referred to as a peaking resource. See Exhibit A-6.2 for more details on the PCA projected operating characteristics for Belle River Power Plant.

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Q31. Why do you consider the natural gas conversion a minor alteration to the power plant?

A31. The natural gas conversion is a minor alteration to the power plant because the majority of power plant equipment and structure that already exists today will continue to be utilized during natural gas-fired operations. This equipment includes major power plant equipment, such as the main unit and auxiliary boilers, steam turbine generators, transformers, boiler feed pumps, feedwater heaters, and common systems such as water treatment and general service water systems. Meanwhile, all coal handling equipment used exclusively for handling coal/ash can be retired. Equipment used exclusively for handling coal/ash includes unloading equipment, storage, hoppers, conveyors and weighing equipment. Company Witnesses Lepczyk and Uzenski describe the proposed accounting treatment for these retiring assets.

Q32. What equipment changes are required to allow the Belle River boilers to operate on natural gas?

A32. Operating Belle River on natural gas requires burner modifications, igniter replacements, a natural gas fuel delivery system, flue gas recirculation systems, and control system alterations.

Q33. How common in the industry is a boiler conversion from coal-fired to natural gas-fired operations?

A33. Converting boilers from coal-fired to natural gas-fired operations is fairly common. As reported by U.S. Energy Information Administration (EIA)[1], 86

[1] https://www.eia.gov/todayinenergy/detail.php?id=44636

coal-fired boilers were converted to burn natural gas since 2011, most of which ceased coal-burning capabilities. In addition, the Belle River Power Plant boilers' original equipment manufacturer (OEM), Babcock and Wilcox (B&W), who was hired to evaluate the conversion of Belle River Power Plant to a natural gas-fired power plant, has been involved in engineering over forty (40) coal-to-natural gas conversions and additions.

Q34. What are the cost savings of the Belle River natural gas conversion as compared to construction of a new natural gas-fueled power plant from a capacity perspective?

A34. The Belle River natural gas conversion is a low-cost alternative to construction of a new natural gas-fueled power plant. It is a low-cost alteration to Belle River Power Plant because it only requires a capital investment of approximately $135 million to retain more than 1,000 MWs (DTE Electric share[2]) of dispatchable capacity and energy available as needed. By comparison, the cost of new combustion turbine peakers would be close to six times more expensive to construct[3] than the cost to convert Belle River Power Plant to natural gas-fueled operations.

Q35. Why do you consider the natural gas conversion an expeditious alteration to the Belle River power plant?

A35. The time needed to engineer, procure, and modify the Belle River plant for natural gas-fueled operations is on the order of two to three years and only requires three

[2] Belle River Power Plant is co-owned by DTE Electric (81.39%) and MPPA (18.61%).
[3] The United States Energy Information Administration (EIA) estimates the total overnight cost of a combustion turbine – industrial frame as $785/kW (https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf) accessed on October 24, 2022.

months per unit of actual unit outage time to complete the conversion. Belle River Power Plant is also able to use its existing MISO interconnection agreement instead of preparing and submitting a new interconnection application. Retiring Belle River Power Plant and submitting an application for a new generation asset would require at least 373 days to go through the MISO generation interconnection process. Limiting the project work scope to a plant fuel change means that only a few power plant system equipment changes would be required.

Q36. How did the Company evaluate the technical feasibility of converting the Belle River Power Plant boilers from coal-fired to natural gas-fired operation?

A36. In order to evaluate the technical feasibility of converting the Belle River Power Plant boilers to natural gas-fired operation, the Company hired B&W in 2020 to perform detailed boiler modeling. The study was concluded in 2021 and determined the boiler conversion to natural gas was feasible and that the plant would continue to have the same general operating parameters experienced with the existing coal-fired operations in the areas of MW output, boiler efficiency, and turbine steam conditions. The results of this study can be found in confidential NDA Exhibit A-6.3 Appendix A.

Q37. Following the confirmation by the OEM that the boilers could be converted to natural gas, what did the Company do?

A37. Since the OEM technical feasibility analysis was focused within the boundary of the boiler, the Company needed further information to understand the full scope, schedule, and cost associated with a possible conversion of the Belle River Power

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Plant boilers to natural gas-fired operation. In order to attain these further details, the Company once again enlisted the expertise of B&W, this time to perform detailed engineering for a more comprehensive evaluation of a potential natural gas conversion. This new work effort included the design of a fuel delivery and control system and isolation or removal of existing coal and ash handling equipment. The results of this detailed engineering analysis can be found in confidential NDA Exhibit A-6.3 and the results of the budget proposal can be found in confidential NDA Exhibit A-6.4.

Q38. How did the Company utilize the information in B&W's budget proposal included in Exhibit A-6.4 to develop a Belle River Power Plant natural gas conversion cost estimate found in Exhibit A-6.5?

A38. Based on the cost information provided in B&W's budget proposal (Exhibit A-6.4), the Company estimated the project management costs and overheads that would be required to support a Belle River natural gas conversion project. The Company estimates its cost for a Belle River natural gas conversion to be $135 million (DTE Electric share), inclusive of $10 million of contingency. A detailed breakdown of this cost estimate can be found in Exhibit A-6.5.

Request for Pre-approval of Belle River Natural Gas Conversion

Q39. Is the Company requesting cost pre-approval for the Belle River natural gas conversion project in this IRP filing?

A39. Yes, the Company is requesting cost pre-approval for $135 million (DTE Electric's Share) to support a Belle River Power Plant natural gas conversion. Details on these costs are included in Exhibit A-6.5. As described by Company

Witness Mikulan, the Belle River Power Plant conversion to natural gas operations was favorable when compared against alternative plans.

Q40. Was this cost estimate included in the IRP modeling of a Belle River gas conversion sensitivity?

A40. Yes, the IRP modeling included conversion costs ranging from $100 - $200 million for the total project ($81 to $163 million for DTE Electric's share of the project). In addition, the final projected cost of $135 million was included in a scenario modeling run completed. Refer to Company Witness Manning for additional details.

Q41. What is the implementation timeline of the proposed conversion at Belle River Power Plant?

A41. The Company would convert the Belle River Unit 1 and 2 boilers to a natural gas-fired configuration during their upcoming major periodic outages. The Company is soliciting bids for the full project in 2022 as an EPC contract. Engineering would be scheduled for completion in 2023. Long-lead material procurement would occur at the beginning of 2024 and pre-outage construction would start in the spring of 2024. Unit 1 would be scheduled for a periodic outage with conversion in the fall of 2025, and Unit 2 would be scheduled for a periodic outage with conversion in the fall of 2026. A more detailed timeline is included in Exhibit A-6.6, which lays out the engineering, procurement, and construction phases of the natural gas conversion project.

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Q42. What is the internal Company approval status of the Belle River Power Plant Gas Conversion project?

A42. The Belle River Power Plant Gas Conversion project received Board of Director approval on September 22, 2022, as shown in Exhibit A-6.7.

Benefits of a Belle River Power Plant Natural Gas Conversion

Q43. What factors did the Company consider when evaluating a natural gas conversion at Belle River Power Plant?

A43. The Company evaluated factors such as economics, reliability, resource adequacy, and impacts to the environment, employees, and community as part of a natural gas conversion evaluation of Belle River Power Plant. Other Company witnesses describe some of these benefits in fuller detail, including Witness Leslie who discusses how the conversion supports the Company's decarbonization efforts and fleet transformation, facilitating the retirement of the first two units of Monroe Power Plant to be accelerated, Witness Mikulan discusses economics and overall considerations in this IRP, Witness Roy discusses grid reliability benefits, Witness Burgdorf discusses resource adequacy benefits, Witness Marietta discusses environmental benefits, and Witness Pratt discusses Belle River Power Plant's fuel resourcing.

Q44. How will Belle River Power Plant emissions be reduced under a natural gas conversion?

A44. The lower utilization (capacity factor) of Belle River Power Plant and the use of natural gas will significantly lower emissions compared to the levels experienced when the power plant was operating as a coal-fired generation resource. The following Table 3 compares the historical coal-fired emissions to projected natural gas-fired emissions for Belle River Power Plant, as well as plant operating statistics.

Table 3: Belle River Power Plant Emission Reductions (Annual)

Description (Total Plant)	Coal-Fired[1]	Natural Gas-Fired[2]	Reduction on Natural Gas	% Reduction on Natural Gas
Net Generation (MWh)	6,271,645	794,566	5,477,079	87%
Capacity Factor (%)	56%	7%	49%	88%
Heat Input (mmBTU)	66,353,272	8,886,326	57,466,946	87%
CO2 Mass (tons)	6,959,125	524,293	**6,434,832**	**92%**
CO2 Rate (lb/mmBTU)	210	118	**92**	**44%**
SO2 Mass (tons)	20,204	3	**20,201**	**~100%**
SO2 Rate (lb/mmBTU)	0.61	0.0008	**0.61**	**~100%**
NOx Mass (tons)	6,832	444	**6,388**	**94%**
NOx Rate (lb/mmBTU)	0.21	0.11	**0.10**	**48%**
PM[3] Mass (tons)	48	0	**48**	**~100%**
PM[3] Rate (lb/mmBTU)	0.0015	0	**0.0015**	**~100%**
Hg Mass (lbs)	54	0	**54**	**~100%**
Hg Rate (lb/TBTU)	0.81	0	**0.81**	**~100%**

1) Based on average annual actual emissions, 2017-2021.
2) Based on average annual projected PCA emissions, 2027-2039.
3) PM is filterable PM only.

Q45. How does the Company's operations and employees benefit from a Belle River Power Plant natural gas conversion?

A45. Currently, Belle River Power Plant has over 250 employees assigned to the site. The conversion to natural gas supports the retention of approximately 60-70 highly-skilled positions in operations, maintenance, engineering, and administration at the Belle River Power Plant that might otherwise be lost if the power plant were to simply retire. Additionally, the Company intends to continue with its commitment to transition employees to other positions. By maintaining this commitment, employees can continue productive careers at the Company enabling the Company to retain the knowledge and skillsets of these employees.

Q46. Did DTE Electric conduct a socioeconomic study to quantify the benefits to the local community of retaining versus retiring Belle River Power Plant?

A46. Yes. DTE Electric commissioned a socioeconomic impact study to evaluate the projected fiscal and economic impacts of a Belle River conversion and full retirement scenario and identify economic vulnerabilities and opportunities unique to the local community. The Company hired Camoin Associates, an economic development consulting firm based in Saratoga Springs, NY, to conduct the socioeconomic impact study. This study is included as Exhibit A-6.8, Socioeconomic Impact Report.

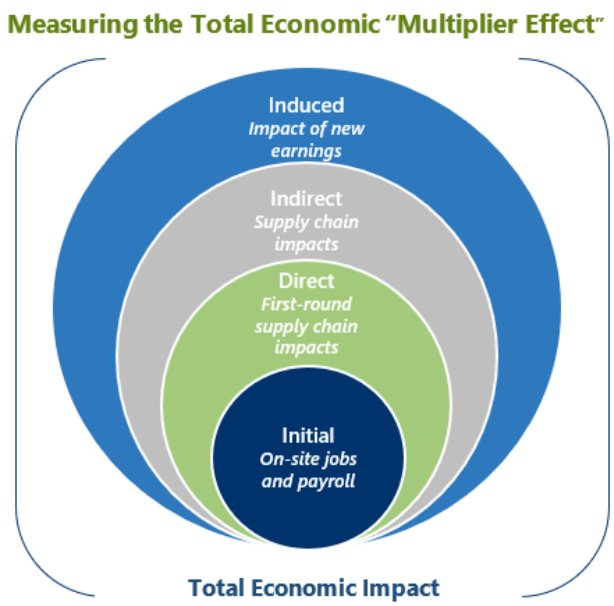
Q47. What was the study's methodology?

A47. Camoin Associates conducted a baseline economic and fiscal impact analysis of the Belle River Power Plant to assess its current contribution to the economy as well as the projected impact of the plant under two scenarios: 1) conversion to natural gas in 2025/2026 and 2) full retirement in 2028. The economic impact on the combined region of China and East China Townships, as well as St. Clair County was considered. The plant sits on twelve land parcels in St. Clair County- four of these parcels are in East China Township, eight are in China Township, and all twelve are in the East China School District. Therefore, the study considered the fiscal impact on the China Township, East China Township, St. Clair County, and East China School District tax jurisdictions.

Impacts were defined in terms of jobs, earnings, and sales, as well as municipal tax revenue. A job is defined as one person employed for some amount of time (part-time, full-time, or temporary) during the study period. Earnings include wages, salaries, supplements (additional employee benefits) and proprietor income. Sales includes an organization's gross expenditures, both to other organizations and to consumers.

Camoin Associates used the Lightcast model (formerly Emsi) to support this analysis; Lightcast designed the input-output model. The Lightcast model allows the analyst to input the amount of new direct economic activity (spending, earnings, or jobs) occurring within the region and uses the direct inputs to estimate the multiplier effects that the net new spending, earnings, or jobs have as these new dollars circulate throughout the economy. The four specific types of impacts considered in the analysis are depicted in Figure 2.

Figure 2. Four Types of Impact Considered in the Economic Impact Analysis



Q48. What are the key findings from the study?

A48. The study found when comparing a conversion of the Belle River Power Plant to retirement, conversion has a greater positive economic and fiscal impact on the community. In China and East China Townships, 100 jobs, approximately $11.2 million in employee earnings and $10.2 million in sales would be supported by the operation of a natural gas plant (Figure 3). In St. Clair County, 169 jobs, approximately $14.2 million in employee earnings and $18.2 million in sales would be supported (Figure 4). These impacts are the total of direct, on-site impact, and all indirect and induced impacts. The impact to St. Clair County is inclusive of China and East China Township impacts. In addition to the ongoing economic impacts of operations, there will be a temporary economic impact to the townships and county as a result of the construction phase of the conversion.

Figure 3 – Economic Impact of Conversion on China and East China Townships

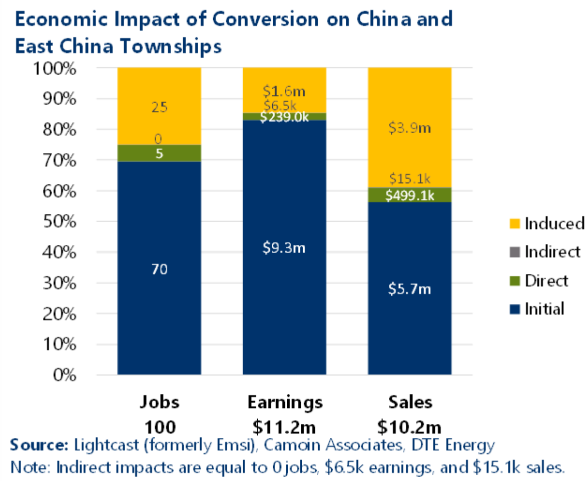
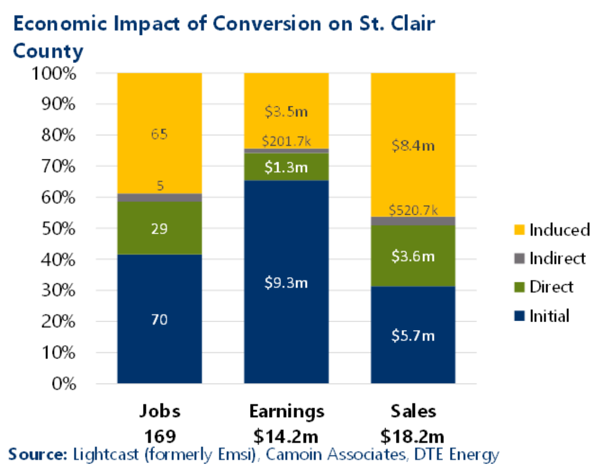


Figure 4 - Economic Impact of Conversion on St. Clair County



Further detail is included in Exhibit A-6.8.

Q49. How would you summarize the Company's proposal to convert the Belle River Power Plant to natural gas-fired operations in the proposed course of action (PCA)?

A49. The Belle River Power Plant conversion to natural gas-fueled operation is the most reasonable and prudent path forward for customers and the Company. As discussed above, the project provides economic, reliability, resource adequacy, environmental, Company operations, employee, and community benefits. The Company's proposed project to convert Belle River Power Plant to a natural gas peaking resource retains a critical dispatchable resource capable of serving customer load when demand is high, for example during peak seasons and/or when intermittent generation is unavailable due to weather conditions. In addition, retaining Belle River Power Plant's critical dispatchable capacity is essential in facilitating the accelerated retirement of Monroe Power Plant coal-fired units. As further discussed by Witness Mikulan, the Belle River natural gas conversion was favorable over other alternatives considered.

SECTION V – PEAKER ANALYSIS

Q50. Can you provide an overview of the general characteristics of the DTE Electric peaker fleet?

A50. Yes. DTE Electric has 1,998 MW of peaker generating capability in its fleet based on the summer capacity ratings of these units. DTE Electric has 82 natural gas and oil-fueled peakers located at 19 different sites. Further details can be found in Section 7 of the IRP Report (Exhibit A-3.1).

Q51. What are the typical operating characteristics of the Company's peaker fleet?

A51. The Company's peaker fleet can be grouped into four major classes: Diesel Engines, Oil-Fired Turbines, Small Gas Turbines, and Large Gas Turbines. Table 4 summarizes the operating characteristics of the peakers as of December 31, 2021, including capacity factor and energy dispatch cost of the various types of peakers.

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Table 4: 2021 Peaker Operating Characteristics

Type	# of Units	Summer Capacity (MW)	Capacity Factor (%)	Approximate Energy Cost ($/MWh)	Gross Heat Rate (btu/kWh)	Approximate Fuel Cost ($/MBTU)
Diesel Engines	46	128	0.3%	$167	10,410	$16.00
Oil-Fired Turbines	10	142	0.3%	$224	13,802	$16.20
Small Gas Turbines	10	189	1.1%	$86	14,404	$6.00
Large Gas Turbines	16	1,539	8.6%	$51	11,537	$4.40
TOTAL	**82**	**1,998**				

Q52. What types of support do peakers provide to the generation and distribution systems?

A52. Peakers are primarily valued for their capacity and ability to startup quickly and reliably in response to high peak demand or distribution reliability issues. As further described by Witness Musonera, peakers provide voltage support as well as support system restoration to the distribution grid.

Q53. How is the Company addressing the Commission's request for a peaker analysis to be included in this IRP as noted on pages 40-41 of the Interim Order dated February 20, 2020, in the Company's 2019 IRP (MPSC Case No. U-20471)?

A53. On February 20, 2020, in its initial order in DTE Electric's 2019 IRP, the Commission ruled that a peaker analysis should be an element in future plans with specific requirements to be defined in the next round of updates to the Michigan Integrated Resource Planning Parameters (MIRPP). Although the MIRPP updates are still pending completion, the Company has performed a peaker analysis. Results of this peaker analysis, which has elements still underway, have been considered in the Company's IRP modeling as discussed by Company Witnesses Mikulan and Manning.

Q54. How did the Company approach the peaker analysis?

A54. The analysis began by reviewing the type of peakers detailed in Table 4 above and determining which type should be further analyzed for this IRP. The Company's large gas turbine[4] peakers are newer, have lower energy and fuel costs, and are expected to continue to run through the study period. For these reasons, they were not included in this analysis. The Company then focused its peaker analysis on the small gas-fired and oil-fired turbines and diesel engines. The Energy Supply and Distribution Operations (DO) teams did not analyze the peakers currently utilized to support plant operations, which includes the Belle River and Monroe diesel engines and Fermi 11-1 and 11-2 oil-fired turbines. The remaining peaker sites were evaluated and include Colfax, Oliver, Placid, Putnam, River Rouge, St. Clair, Wilmot, Northeast, Fermi, Superior, and Hancock. The Slocum peaker site, as discussed below, has been identified for a battery pilot.

Q55. What was considered in the peaker analysis performed?

A55. The analysis evaluated whether to continue operations or retire the peaking units. Consistent with evaluating generating resources, the peaker analysis was based on economics, resource adequacy, and grid reliability (transmission and distribution). The peaker analysis included forecasts of future O&M and capital costs for each peaker unit which is included in my Exhibit A-6.9, an economic screening analysis as discussed by Witness Cejas Goyanes, a distribution system impact review as discussed by Witness Musonera, and transmission impact review discussed by Witness Roy. In addition, a peaker retirement sensitivity was completed in the EnCompass optimization model to understand the impact of potentially retiring

[4] The Company's large gas turbine sites include Belle River, Dean, Delray, Greenwood, and Renaissance.

River Rouge 11, St Clair 12, Fermi 11-3, and Fermi 11-4 peaker units. Refer to Witness Manning for additional detail on this sensitivity.

Q56. How did the economic and grid reliability results factor into the site-by-site recommendations?

A56. Peaker sites that were economic compared to retirement are recommended to remain operational. Peaker sites that were not economic and would not necessitate distribution system upgrades are being studied by MISO for potential retirement. Peaker sites that were not economic but would require distribution upgrades to enable their retirement require further evaluation to fully understand the associated distribution costs and upgrades required.

Q57. What are the results of the Company's analysis of the diesel engine peakers[5]?

A57. The economic results are shown in detail by Company Witness Cejas Goyanes in his exhibit A-4.5, and the distribution system impacts are shown in detail by Company Witness Musonera in her Table 2, and the transmission impacts are discussed by Company Witness Roy.

- Being retained in operational status are the 15 units at the Colfax, Placid, and Putnam sites. The forecasted cost to continue operating the units was less costly than the option of retiring these diesel peakers and upgrading the distribution system to support distribution system reliability requirements.
- The 10 units at the Oliver and Wilmot sites will be studied to understand potential impacts to the distribution system. As discussed by Witness

[5] The diesel engine sites include Belle River 11, Colfax 11, Monroe 11, Oliver 11, Placid 12, Putnam 11, River Rouge 11, Slocum 11, St Clair 12, and Wilmot 11.

Musonera, additional studies will be performed to further understand the distribution upgrade impacts.

- The six peaker units at River Rouge and St. Clair sites are being evaluated for retirement based on the results of the economic analysis, impact to the distribution system, and results of the environmental justice analysis as described by Witness Marietta. The Company engaged MISO to study the impacts to the transmission system from the potential retirement of the peakers. Witness Roy further describes the current status of that study.
- The five units at Slocum are to be replaced with a grid scale battery as discussed later in my testimony.

The potential diesel engine peaker retirements discussed above for River Rouge, St. Clair, and the replacement at Slocum with a battery total 11 of the 46 (24%) diesel peaker units currently in operation. The Energy Supply and DO teams will continue to collaborate on the evaluation of diesel-fired peakers that require additional analysis.

Q58. What are the results of the Company's analysis of the oil-fired turbine peakers [6]?

A58. The economic results are shown in detail by Company Witness Cejas Goyanes in his exhibit A-4.5, the distribution system impacts are shown in detail by Company Witness Musonera in her Table 2, and the transmission impacts are discussed by Company Witness Roy.

- For the Northeast 13 and Superior 11 units, the economic analysis indicates retaining their operation is favorable as compared to their retirement and

[6] The oil-fired turbine sites include Fermi 11, Northeast 13, and Superior 11.

electrical system upgrades. As such, the Company plans to continue their operation.

- Based on the economic analysis and lack of distribution system impacts, the Company is evaluating if retirement is an option for two of the four oil-fired turbines at Fermi. The Company engaged MISO to study the impacts to the transmission system from the potential retirement of these peakers. Witness Roy further describes the current status of that study. In addition, the Company is determining if there are any potential nuclear licensing issues.

The potential retirements discussed above (two Fermi units) represent a 18% reduction in oil-fired turbine installed capacity.

Q59. What recommendation is the Company making related to the small gas-fired turbines[7] based on the economic and distribution system impact analyses?

A59. The economic results are shown in detail by Company Witness Cejas Goyanes in his exhibit A-4.5 and the distribution system impacts are shown in detail by Company Witness Musonera in her Table 2.

- The Northeast 11-1 peaker experienced a major failure in 2019. After extensive evaluation of repair alternatives, the Company has decided to retire the unit and has requested MISO to study potential transmission impacts.
- For the small gas turbines at Northeast 11-2, 11-3, 11-4, and 12 units, Hancock 12, and St Clair 11, the economic analysis indicates retaining

[7] The small gas-fired turbine sites include Hancock 11, Hancock 12, Northeast 11, Northeast 12, and St Clair 11.

their operation is favorable compared to retirement and electrical system upgrades. As such, the Company plans to continue their operation.

- The Hancock 11-1 and Hancock 11-3 will be studied to understand potential impacts to the distribution system. As discussed by Witness Musonera, additional studies will be performed to further understand the distribution impacts.

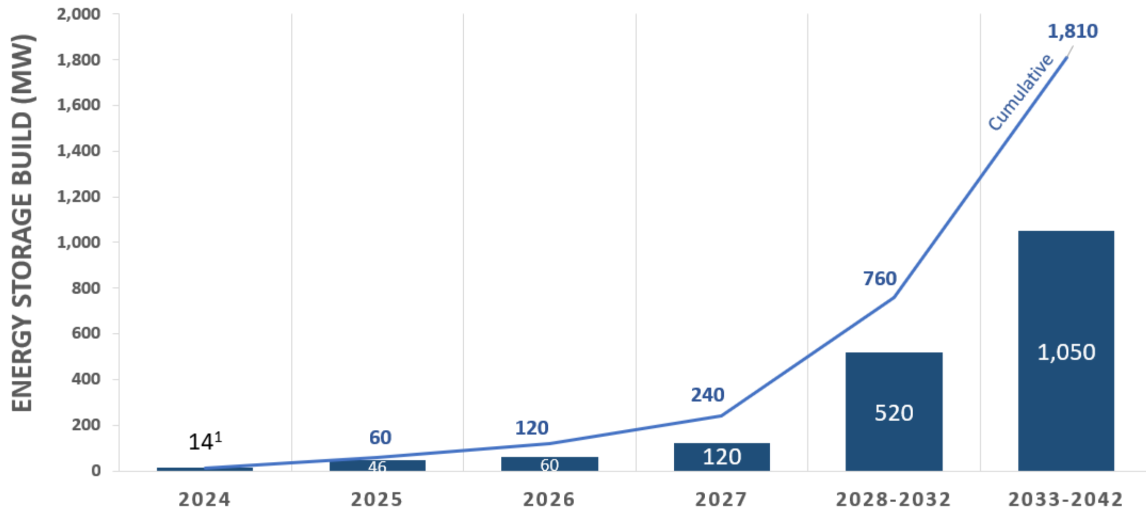
The retirement of Northeast 11-1 will result in 10% of the small gas-fired turbines being retired. The Energy Supply and DO teams will continue to collaborate on the evaluation of small gas-fired peakers that require additional analysis.

SECTION VI – BATTERY ENERGY STORAGE SYSTEM PILOT AND FUTURE BUILD

Q60. What amount of battery energy storage build is included in the Company's PCA?

A60. The Company's PCA includes a gradual build-up of 240 MW of energy storage over the next five years (2023-2027), an additional 520 MW of battery storage in 2028-2032, and 1,050 MW of new batteries in 2033-2042. The incremental energy storage build is included in Figure 5 below:

Figure 5 – Incremental Energy Storage Build



1. The 14 MW build in 2024 represents the Company's Slocum Battery Energy Storage System (BESS) Pilot

Q61. Does the Company currently have any grid scale batteries?

A61. No, it does not.

Q62. Can you describe the steps being taken by the Company to initiate the integration of additional battery energy storage into its resource fleet?

A62. The Company's first Battery Energy Storage System (BESS) is the 14 MW Lithium-ion battery system at the Slocum peaker site that follows MPSC guidelines (Case No. U-20645) for pilot projects. This project was included by the Company in its 2022 Main Electric Rate Case U-20836. The project will provide the Company with experience engineering, procuring, constructing, and operating its first grid scale battery.

Q63. Can you describe the expected utilization of the Slocum BESS?

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A63. The Slocum BESS pilot project currently scheduled to be completed in 2024 will replace the current five diesel peaker engines totaling 14 MW at the Slocum site. The BESS is a lithium-ion battery system that will have 56 MWh of energy storage. The battery system will be charged utilizing lower cost off-peak energy and discharge that energy during higher value on-peak hours to capture market energy value for our customers. The plant is expected to operate (charge and discharge its stored energy) on a daily basis. A BESS is an energy storage system and not a generating unit and as such will not consume fuel and will not itself produce any environmental emissions. The operation of a BESS is silent and current technology supports round trip efficiencies exceeding 85%.

Q64. Is the Company requesting pre-approval for capital expenditures associated with a grid scale BESS in this proceeding?

A64. No, the Company is not requesting pre-approval of grid scale BESS in this proceeding.

Q65. What build limits were incorporated into the IRP modeling for utility-scale batteries?

A65. The IRP modeling limited annual utility-scale battery build to 500 MW prior to 2027, 800 MW between 2027 and 2039, 1,200 MW between 2031 and 2035, and 2,000 MW after 2035.

Q66. What was the basis for limiting utility-scale battery build in the IRP Model?

A66. Utility-scale battery technology is a commercially available technology with large industry growth projected. Growth in mining raw materials and manufacturing

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batteries will be needed to support the projected buildout. The federal government has documented concerns with existing battery supply chains, which have been the focus of federal policy initiatives related to domestic manufacturing and purchasing incentives, as well as research, development and demonstration funding.[8] In addition, as discussed by Company Witness Hernandez, there is a large influx of projects (renewable, energy storage, renewable-storage hybrid resources) in the MISO interconnection queue , which is a time-consuming process that has historically experienced delays. This growth is expected to be bolstered by the introduction of additional incentives in the Inflation Reduction Act.[9] As such, it is reasonable to expect battery component availability and interconnections to be limited in the near-term as supply chains must grow to match projected demand, interconnection processes need to improve, and the grid requires upgrades to integrate energy storage and other assets.

Q67. Why does the Company support the major deployment of battery storage systems in both the near term and long-term timeframes of the PCA?

A67. The deployment of battery storage on a major utility scale is needed to support the planned additions of intermittent generating assets. Battery storage will allow the production and release of energy to the Company's customers to match their needs while still allowing the wind and solar renewable assets to generate at their maximum capabilities.

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[8] Battery supply chain, https://www.whitehouse.gov/wp-content/uploads/2021/06/100-day-supply-chain-review-report.pdf; accessed October 21, 2022; https://www.energy.gov/sites/default/files/2022-02/Energy%20Storage%20Supply%20Chain%20Report%20-%20final.pdf; accessed October 21, 2022; https://www.energy.gov/articles/doe-announces-actions-bolster-domestic-supply-chain-advanced-batteries; accessed on October 21, 2022

[9] Inflation Reduction Act, https://about.bnef.com/blog/global-energy-storage-market-to-grow-15-fold-by-2030/; accessed on October 21, 2022

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Q68. Does this conclude your testimony?

A68. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEEGAN O. FARRELL

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEEGAN O. FARRELL

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

A1. My name is Keegan O. Farrell. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or the Company) as the Manager of Demand Response.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company.

Q3. What is your educational background?

A3. I graduated from Michigan State University, with a Bachelor of Arts Degree in Communication. In addition, I received a Master of Science Degree in Decision Technologies from the University of North Texas.

Q4. What is your professional experience?

A4. From 2008 until 2012, I was employed by DTE Gas Resources, LLC in Fort Worth, Texas where I held positions of increasing responsibility, ultimately serving as a Decision Support Analyst. In this role, I was responsible for assisting with calculating reservoir economics, monitoring daily oil and natural gas production, and overseeing the compliance and emission calculations for the Environmental Protection Agency's Greenhouse Gas Reporting Program (Subpart W). In 2012, I joined DTE Energy as a Senior Business Financial Analyst – Load Research. In 2014, I was promoted to Principal Financial Analyst – Load Research. In this position, I was responsible for developing and implementing statistical sampling programs used to evaluate customer class usage characteristics, developing allocation schedules for use in cost-of-service studies and rate design, and for

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measuring and evaluating demand response programs offered by the Company. In 2018, I accepted the position of Supervisor Program Management – Demand Response.

Q5. What is your current position?

A5. In 2021, I was promoted to Manager of Demand Response. In this position I am responsible for overseeing DTE Electric's Demand Response (DR) portfolio, which includes the short- and long-term strategic development of DR programs. I am also responsible for the development and implementation of gas DR.

Q6. Do you participate in any industry associations?

A6. Yes. I am the course coordinator for the Association of Edison Illuminating Companies (AEIC) Fundamentals for Load Data Analysis course. In addition, I represent DTE Energy on the board of the Peak Load Management Alliance (PLMA).

Q7. Have you received any additional training?

A7. Yes. I have completed the AEIC Fundamentals of Load Data Analysis course. I have also attended various courses at Michigan State University Institute of Public Utilities Annual Regulatory Studies Program as well as the Demand Response Fundamentals and Evolution Course presented by the PLMA.

Q8. Have you previously testified before the Michigan Public Service Commission?

A8. Yes, I have sponsored testimony and exhibits before the Michigan Public Service Commission (MPSC) in the following DTE Electric cases:

Case No.	**Description**
U-18014	DTE Electric 2016 General Rate Case
U-18255	DTE Electric 2017 General Rate Case
U-20162	DTE Electric 2018 General Rate Case
U-20471	DTE Electric 2019 Integrated Resource Plan (IRP)
U-20521	DTE Electric 2017-18 Demand Response Reconciliation
U-20793	DTE Electric 2019 Demand Response Reconciliation
U-21044	DTE Electric 2020 Demand Response Reconciliation
U-20836	DTE Electric 2022 General Rate Case
U-21242	DTE Electric 2021 Demand Response Reconciliation

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Purpose of Testimony

Q9. What is the purpose of your testimony?

A9. The purpose of my direct testimony is to:

- Discuss DTE Electric's existing DR portfolio including residential, commercial and industrial customer programs and tariffs;
- Discuss the current and planned pilot programs to evaluate and develop new products and services to be added to the existing portfolio of DR programs;
- Describe the DR assumptions and inputs that were provided to the IRP team to be modeled; and the amount of DR in the Proposed Course of Action (PCA) and;
- Provide capital costs for the time-period 2023-2025 for which the Company is asking pre-approval.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-7.1	Demand Response Existing Programs for IRP Modeling
A-7.2	Demand Response Inputs for IRP Modeling
A-7.3	Demand Response Capital Costs for Pre-Approval

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes.

Q12. How is your testimony organized?

A12. My testimony consists of the following five (5) parts:

Part I - DR Program Overview and Existing DR Programs
Part II - DR Pilots
Part III - Summary of DR Assumptions and Inputs
Part IV - DR in the Proposed Course of Action
Part V - DR Capital Costs for Pre-Approval

Part I: DR PROGRAM OVERVIEW AND EXISTING DR PROGRAMS

Q13. What is the purpose of DR programs?

A13. DR programs are designed to reduce or shift enrolled customers' energy use during periods of peak or high demand. The reduction or shift in customer usage from DR programs can provide value to both the utility and all customers by reducing the need for additional generation, resulting in lower energy costs. Customers participating in DR programs can benefit from lower bills and/or incentives when utilizing the programs. If the DR programs are less costly than other capacity resources, the utility and all customers can benefit from displacing or deferring the need for new generation resources.

Q14. Could you describe the Company's current DR portfolio?

A14. Yes. The Company currently receives capacity credit from the Midcontinent Independent System Operator (MISO) from its established DR portfolio, which is a diverse set of programs for residential, commercial, and industrial customers. In addition, the Company continues to invest in various pilots to enhance the current portfolio offerings, as well as leverage new technologies. The goal of the Company's DR programs is to deliver measurable peak demand reduction by effectively engaging customers to manage and shift their energy consumption.

Pilots are potential programs focused on understanding technology or design and determining whether they are capable of becoming full-scale programs that will deliver accountable peak demand reduction or shifts in energy consumption. Pilots can eventually become programs in the Company's DR portfolio if they prove to be successful.

Q15. What programs in the Company's DR portfolio are registered as Load Modifying Resources (LMR) that receive MISO capacity credit?

A15. The following are descriptions of each program within the DR portfolio that are registered as LMRs:

- Interruptible Space-Conditioning Rate (D1.1): Commonly referred to as "IAC" or Cool Currents, consists of a separately metered service connected to the customer's central air conditioner (A/C) or heat pump and is available to residential and commercial customers. DTE Electric will cycle the A/C condenser or heat pump by remote control on selected days for intervals of no more than 30 minutes in any hour and no more than eight hours in any day. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load
- Dynamic Peak Pricing (DPP) Rate (D1.8): Residential and Commercial customers can choose to take service under this whole-home rate and receive a discounted per kilowatt rate during certain hours of the day and week in exchange for paying a higher rate of $0.95 per kilowatt hour for energy used during Critical Peak Pricing (CPP) event hours. The CPP event attribute of this

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rate is what is given capacity credit by MISO. The Company can implement CPP events for several factors including, but not limited to economics, system demand or capacity deficiency. The SmartCurrents[1] program provides additional savings to the customer by providing them with a Wi-Fi enabled thermostat that can be adjusted during CPP events. CPP events are limited to 14 per year and only available on non-holiday weekdays from 3:00 p.m. to 7:00 p.m.

- 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, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load
- Interruptible Water Heating Service Rate (D5): This program is available to customers (both residential and commercial) using hot water for sanitary purposes or other uses subject to the approval of the Company. A timer or other monitoring device controls the daily use of all controlled water heating service. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load. Events can be called for no longer than four (4) hours per day
- Interruptible Supply Base Service Rate (D8): Primary voltage customers who desire separately metered service for a specified quantity of demonstrated

[1] A customer can take service under the Dynamic Peak Pricing rate and not be enrolled in SmartCurrents but a customer who is enrolled in SmartCurrents must take service under the Dynamic Peak Pricing rate.

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

- 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
- 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 a 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
- 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, but 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
- Capacity Release (Rider 12): Customers are provided 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 from June 1 – September 30

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- Smart Savers (Bring-Your-Own-Device/BYOD): Customers who have a Wi-Fi enabled smart thermostat installed can opt to have the Company adjust the thermostat up to four (4) degrees during an event in exchange for an annual incentive. The Company can implement Smart Saver events for several factors including, but not limited to economics, system demand or capacity deficiency. Only 14 events can be called between June 1 – September 30 and events are limited to non-holiday weekdays from 12:00 p.m. – 8:00 p.m. Events are limited to no more than four (4) hours at a time

Table 1 shows the MWs associated with each program in the Company's last capacity demonstration, case U-21099.

Table 1: LMRs in the MISO 2022-2023 Year

Program	MW (UCAP)
R10 – Interruptible Supply Rider	353
D1.1 – Interruptible Space Conditioning	218
D8 – Interruptible Supply Rate	118
R1.2 – Electric Process Heat	72
Smart Savers (BYOD)	61
R12 – Capacity Release	45
D3.3 – Interruptible General Service Rate	22
D1.8 – Dynamic Peak Pricing Rate	11
R1.1 – Alternative Metal Melting	4
Total	**904**

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Part II: DR PILOTS

Q16. What are the Company's plans for future DR programs?

A16. DTE Electric is conducting additional DR pilots that follow the MPSC Pilot Guidelines provided in MPSC 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.

Q17. What is the Company's overall approach to develop and manage the ongoing and future DR pilots?

A17. As described at the beginning of my testimony, the Company designs and executes DR programs to help customers reduce their peak energy use, which provides value to the participating customers, in the form of savings or other compensation, to the utility through reduced capacity needs and lower capacity costs, and all customers through reduced overall system costs. The Company has several successful, long-term programs which support its peak-reduction objectives, and many other pilot

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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 and programs that may become economic alternatives to capacity and have an appropriate level of customer adoption potential.

Q18. What pilots is the Company currently evaluating or planning to evaluate?

A18. The Company is currently evaluating multiple DR pilots that could potentially become part of the DR portfolio including:

- Peak Time Savings (PTS)
- Electric Vehicle (EV) DR Pilot
- Residential Whole-home Generator Pilot
- Commercial & Industrial (C&I) Storage Pilot
- Commercial & Industrial Dashboard Pilot

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PART III. SUMMARY OF DR ASSUMPTIONS AND INPUTS

Q19. How much DR was approved in the Company's 2019 IRP?

A19. In the 2019 IRP, the approved PCA grew DR from 709 MWs (UCAP) in 2019 to 859 MWs (UCAP) in 2024 and held that level steady through 2040.

Q20. What is the starting point for DR in the 2022 IRP?

A20. The Company has been able to grow the DR portfolio of approved programs above what was forecasted in the 2019 IRP. The starting point for the 2022 IRP is consistent with the 2021 Capacity Demonstration Case No. U-21099 which shows DR MWs growing from 920 MWs (UCAP) in 2023 to 949 MWs (UCAP) in 2026. This level is expected to remain relatively flat through the remaining study period of 2042. The existing demand response program levels and forecasted growth data was provided to the IRP team for inclusion into the IRP modeling process and is included in Exhibit A-7.1.

Q21. How was the Company able to grow the current DR portfolio to levels above what was forecasted in the 2019 IRP?

A21. Portfolio growth is partly attributed to the continued investment in the Load Control Device (LCD) replacement program for customers on the Interruptible Space Conditioning rate. Customer enrollments in the Company's Rider 12 Capacity Release Tariff is another contributor. The Company began actively marketing the Rider 12 Capacity Release Tariff which was not included in the 2019 IRP. The final contributor is the load reduction from two (2) residential and commercial thermostat programs, SmartCurrents and Smart Savers, that were still considered pilots in 2019 and are now programs.

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Q22. In addition to the current DR portfolio and its assumed growth, what other information did you provide the IRP team to be modeled?

A22. I provided the IRP team with a list of DR programs, their annual costs and potential MWs that were deemed to be cost effective over the next 20 years as detailed in the State of Michigan by the 2021 Statewide Demand Response Potential Study[2] ("Statewide Potential Study"). The Statewide Potential Study included incremental MWs beyond what is recognized by current DR programs in the state of Michigan as well as MWs from new DR programs.

Q23. Could you describe the 2021 Statewide Demand Response Potential Study?

A23. Yes. The 2021 Statewide Demand Response Potential Study was Commissioned by the MPSC and conducted by Guidehouse. The study was completed on September 24, 2021 and evaluated various DR technologies for the years 2021 through 2040. The objective of the study was to estimate the potential for cost-effective DR as a capacity resource and included an assessment of both electric and natural gas DR potential. The study assessed both summer and winter peak demand reduction potential for electric.

The study developed the DR potential and cost estimates for the State of Michigan using a bottom-up analysis. Guidehouse collected customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR

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[2] 2021 Statewide Demand Response Potential Study can be found at: 2021 Energy Waste Reduction and Demand Response Statewide Potential Study (michigan.gov), https://www.michigan.gov/mpsc/commission/workgroups/2021-energy-waste-reduction-and-demand-response-statewide-potential-study, accessed October 20, 2022

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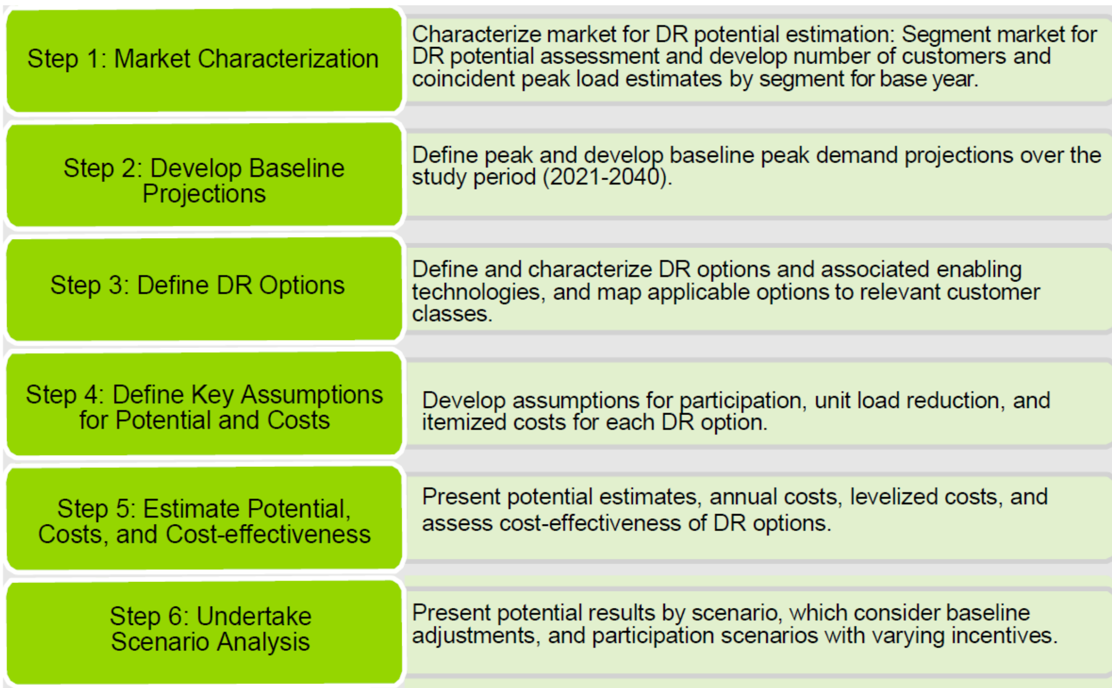
program information from Michigan utilities, and well-established and latest available information from the industry on DR resource performance and costs. The six-step approach to assess the DR potential is displayed in Figure 1.

Figure 1: DR Potential Assessment Steps



In addition to the study providing the amount of cost-effective DR potential in the State of Michigan, accompanying data sheets also broke down the cost-effective programs and the associated costs and MWs for each Michigan utility including DTE Electric.

Q24. What was the objective of the Statewide Potential Study?

A24. The objective of the study was to estimate the potential for cost-effective DR as a capacity resource across the State of Michigan from 2021 to 2040.

Q25. Is the Statewide Potential Study an appropriate data source to use in the 2022 IRP?

A25. Yes. On May 26, 2022, Order in the instant case, U-21193[3], the Commission found that the Company's use of the Statewide Potential Study, rather than the previous 2017 Demand Response Potential Study, is reasonable. The Commission further found that use of the Statewide Potential Study allows for the most recent data to be used in the Company's IRP and provides more relevant information for modeling purposes.

Q26. What DR programs were identified to be cost-effective based on the Statewide Potential Study?

A26. The Statewide Potential Study laid out various programs that were cost-effective within the lower peninsula across three (3) different scenarios which represent different input parameters for participation, incentive levels, distributed energy resources (DER) adoption, avoided costs, and energy waste reduction (EWR)-related adjustments. DR programs that the 2021 Statewide Potential Study identified as being cost-effective for the lower peninsula are:

- Time-of-Use (TOU) – rates that vary by block of hours during the day and by season
- Real Time Pricing (RTP) – Dynamic rate with hourly variation in price
- C&I Demand Bidding – Voluntary load reduction when DR events are called
- C&I Capacity Reduction – Firm capacity commitment for load reduction during DR events

[3] Case No. U-21193, Order dated May 26, 2022, pg. 3

- Critical Peak Pricing (CPP) – Significantly higher price during certain critical hours of the year superimposed on a TOU rate
- Voltage Optimization (VO) – Energy and demand reduction using front-of-the-meter VO technologies
- Bring Your Own Thermostat (BYOT) – Space cooling and heating control using smart thermostats
- Behavioral DR – Modifications in demand during peak demand period due to behavioral changes, induced by social comparisons
- Behind the Meter (BTM) Battery Dispatch – Dispatch of BTM batteries during DR events
- Peak Time Rebate (PTR) – Discounted rate for reducing electricity use over baseline during DR events
- EV Managed Charging – Managed charging of plug-in hybrid electric vehicles (PHEVs) and EVs
- Direct Load Control-Switch (DLC) – Control of space cooling and heating equipment and electric water heating using load control switches

Q27. How did the Company model DR based on the Statewide Potential Study?

A27. After the completion of the Statewide Potential Study, Guidehouse offered utilities the option to receive extrapolated service area-specific results from the study. I provided the IRP team with the specific program inputs (i.e., annual cost and MWs) that were applicable to DTE Electric from the service-area specific results. For some programs, I looked at the MWs by sub option, which represent combinations of different end-uses and enabling technologies, that were provided in the data sheets that accompanied the study. I provided the costs and DTE specific programs

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and applicable sub options to the IRP team to be modeled. For example, in the Statewide Potential Study, CPP was found to be cost effective for the lower peninsula. However, rather than providing the IRP team with all the MWs and cost associated with CPP, I only provided the MWs and costs associated with the sub option of CPP, which was CPP with enabling technology. This is because the SmartCurrents program that is currently offered as a demand response program is classified as a CPP with enabling technology offering and the Company is committed to the continued growth of the SmartCurrents program. In addition, I provided the sub option associated with the Peak Time Rebate (PTR) program without enabling technology. This aligns with the Company's current Peak Time Savings (PTS) pilot.

Q28. How did the Company define the amount of DR potential available for each program?

A28. The Company relied on the data sheets that accompanied the Statewide Potential Study to determine the amounts of DR potential available. The only modifications to the Statewide Potential Study that were made was shifting the start year of the study from 2021 to 2023 making the study run from 2023 to 2042, rather than 2021 to 2040. Also, since the potential study did not take into consideration any program growth from the time data was submitted to the time the potential study was published, I discounted the MWs of the Bring Your Own Thermostat program, Critical Peak Pricing with Enabling Tech, and the C&I capacity reduction to reflect DTE Electric's existing levels. The achievable potential by DR option (MWs and costs) that I provided the IRP team to be modeled can be found in Exhibit A-7.2.

Q29. What data source did the Company use to model DR program costs?

A29. The Company relied on the annual costs that were provided by program option and sub-option from the Statewide Potential Study.

Q30. Did the Company include any other costs in its modeling of DR programs that are in addition to the costs provided in the Statewide Potential Study?

A30. Yes. Per the order in U-18369, the Company can receive a financial incentive up to 15% on all non-capital spend. As costs associated with demand response are more Operations and Maintenance (O&M) and incentive based, I added 15% to the projected non-capital cost portion of each program to accurately reflect the cost of each program if the Company were able to receive the maximum financial incentive allowed.

PART IV. DR IN THE PROPOSED COURSE OF ACTION

Q31. What level of DR is included in the PCA?

A31. No additional DR beyond the current portfolio's growth that the Company is forecasting was selected.

Q32. Why does the Company believe that continuing to invest in DR pilot programs is beneficial even if they are not selected in the Proposed Course of Action (PCA)?

A32. DR pilots provide the Company with valuable information about how to integrate the various programs with the Company's equipment, systems, and processes as well as to assess customer appetite for such programs. If a pilot program is selected to be commercialized, the Company puts together the necessary planning, marketing, and implementation processes to have a successful launch of the program. This approach helps the Company to reduce the ensuing ramp-up time necessary to quickly and cost-effectively run those programs when capacity and reliability needs emerge as well as evolve with the latest technology.

In addition, conducting pilots help the Company understand event performance and the sustainability of the resource. Pilots allow the Company to test different event parameters (i.e., length of events, notification window, etc.) to assess which parameters produce the greatest load reduction and highest level of customer engagement.

Q33. Does the Company believe there are any risks if the reliance on DR were to increase in the future?

A33. Yes. As discussed by Witness Burgdorf, DR constitutes about 10% of load across the MISO region. With increased reliance on DR, there is an increased probability that DR will be called in response to operational conditions. Several factors, including extreme weather and tightening capacity supplies across the MISO region, may lead to DR being called more frequently. The frequency of events may affect customer willingness to sign up for and maintain participation in DR programs. As the Company adds additional DR, current and new program participation and performance will and should be continuously monitored.

Q34. Do you believe there are any additional risks with relying on DR?

A34. Yes, as explained by Witness Burgdorf, MISO is changing how DR resources are accredited. Some of the Company's programs in the DR portfolio will have to be changed to meet MISO full accreditation requirements, such as Smart Savers that is currently limited only to 14 events during the summer (June – September). In order to change the parameters of the program and get them approved, the Company will have to work with various thermostat vendors and the program implementer. A change in these event parameters to meet MISO requirements, such as the number of interruptions, could lead to customers no longer wanting to participate in DR programs as they may find certain programs no longer fit their lifestyle. It is also possible that the certain thermostat vendors will not agree to the new program requirements resulting in a reduced seasonal accreditation.

Q35. What steps is the Company taking to minimize or reduce attrition in its existing DR programs?

A35. The Company continues to conduct customer research and benchmarking to improve customer experience and satisfaction with its DR programs. The Company has increased its focus on program education, including providing more savings tips, program reminders and feedback – each reflective of customer feedback. Initial results of providing such education through programs like SmartCurrents have been positive. In the next year, the Company will begin developing a DR landing page to serve as a centralized repository for DR programs and information on dteenergy.com to aid in customer education. The landing page will aim to provide potential and existing DR program participants with an overview of DR, programs available, tools for selecting the best fit program, and summarize current and historical events and their impact. Additionally, the Company is investigating increasing participation incentives to align with peer utilities and comparable programs.

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Q36. What is the Company doing to prepare for changing MISO accreditation requirements?

A36. The Company will continue to work with customers to make sure they understand any change in requirements and are able to comply when called upon or unenroll if they cannot. The team will also continue to work to modify or add DR programs that will allow the Company to get full accreditation from MISO.

Part V: DR CAPITAL COSTS FOR PRE-APPROVAL

Q37. Is the Company requesting pre-approval of the projected spend for cost recovery purposes to develop and execute their DR initiatives?

A37. Yes. The Company is requesting pre-approval for capital dollars that will continue to advance the DR portfolio in both MWs and technology.

Q38. How much capital is the Company requesting pre-approval of for the incremental DR resources?

A38. The Company is requesting pre-approval of $8.7 million of capital expenditures over the three-year period from 2023-2025 to support the sustainment and growth of the Cool Currents and SmartCurrents programs as well as the continued implementation of the C&I Dashboard. The Company also plans to begin a water heating switch replacement project for residential and commercial customers who take service on the Company's interruptible water heating rate. For a more detailed description of the capital costs for which pre-approval is being requested, please refer to Exhibit A-7.3.

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Over the same period, the Company is estimating that the O&M expenditures associated with the continued development and management of those same programs to be $3.15 million, not including any financial incentive that the Company may be receive. The Company is not seeking pre-approval of the associated O&M dollars in this proceeding.

Q39. Could you describe the C&I Dashboard that you are requesting capital pre-approval for?

A39. Yes. The Company is planning to partner with a program implementer to provide C&I customers who take service under a DR tariff (i.e. D8, R10 and R12) with technology and software so customers can better understand and sequentially, improve upon their event performance. In addition, the technology can provide more advanced analytics for better DR forecasting for the Company to provide to MISO as well as improved post-event analysis.

The technology will provide real-time telemetry to the customer and the Company, so the event performance is monitored in real-time and displayed on a dashboard for the participating customer and the Company. The instantaneous feedback lets both the customer and the Company know if additional actions need to be taken to reduce load to committed levels.

Q40. Could you elaborate on the plans to replace water heating control units?

A40. Yes. The Company plans to begin the replacement of approximately 48,000 residential and commercial water heating load control devices (LCDs) for customers who currently take service under the interruptible water heating service

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rate or D5. By taking service under this separately metered rate, customers' water heating units can be interrupted remotely by the Company in exchange for a discounted energy charge on the associated usage. The Company has identified that the original LCDs that currently reside in customers' homes have reached the end of life and no longer function as intended. The pilot will also study the feasibility of recruiting new customers onto the interruptible water heating rate. It is believed that the replacement of these units will account for 6 MWs (UCAP) of load reduction beginning in 2026, which is consistent with the 2022 starting point and reflected in Exhibit A-7.1.

Q41. Will the Company reconcile its DR cost projections in future DR filings?

A41. Yes. Consistent with the regulatory process ordered in case U-18369, the Company will reconcile any capital costs approved in this IRP in annual DR reconciliations filed after an order is issued in this proceeding and costs are incorporated into rates in a following rate case.

Q42. Does this complete your direct testimony?

A42. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEVIN L. BILYEU

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEVIN L. BILYEU

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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 the 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's Degree in Business Administration from the University of Michigan.

Q4. Please describe your work experience.

A4. In 2006, I began my professional career with SEMCO Energy Gas Company where I held various positions of increasing responsibility. In 2008, I accepted the position of Billing Analyst which included responsibilities such as providing business expertise and support to stakeholders, performing reviews, project management, and recommending improvements in various processes. In 2011, I accepted the position of Supervisor of Customer Accounting which included responsibility for customer billings, remittance processing, inactive collections, bad debt, and financial reporting for the Customer Accounting Department. In 2013, I accepted the position of Manager, Customer Energy Management, which included the overall administration, monitoring, and development of Energy Waste Reduction (EWR) Programs, providing testimony and support for the filing of

EWR plans and reconciliation cases at the Michigan Public Service Commission (MPSC), and monitoring, planning, and administering the home protection warranty program.

My employment with DTE Electric began in 2015 as the Principal Marketing Analyst of EWR Pilot programs. In this role, I was responsible for pilot program development and management activities for new EWR programs. In 2016, I accepted the position of Principal Marketing Specialist of EWR Strategy, which included energy efficiency Integrated Resource Plan (IRP) modeling for long-term strategy planning. I also had responsibility for developing sensitivities, and recommendations for energy efficiency strategies in support of EWR plan filings with the MPSC.

In 2018, I became the Principal Supervisor of EWR Strategy. In this role, I was responsible for the overall strategic development and planning of EWR programs, including IRPs and EWR regulatory filings.

Q5. What is your current position and what are your current responsibilities?

A5. In 2021, I became the Manager of EWR Strategy and Evaluation Measurement & Verification (EM&V). In this role, I am responsible for the overall strategic development and planning of EWR programs, including IRPs and EWR regulatory filings; the assurance of program cost effectiveness; and evaluation of EWR programs and application of results.

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Q6. Are you a member of any professional organizations?

A6. 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 promotes the transfer of knowledge and experience to promote energy efficiency programs. I am a member of the Consortium for Energy Efficiency (CEE), engaging on its benchmarking 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.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission?

A7. Yes. I sponsored testimony in the following cases:

U-17362	SEMCO Energy Gas Company EO Plan 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

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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 energy EWR programs;
2. Describe the Company's EWR performance in terms of energy savings, capacity savings, and program costs for the period 2009-2021;
3. Describe the EWR assumptions and inputs used in the Company's 2022 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-8.1	Projected Energy Waste Reduction Savings and Spend
A-8.2	DTE Electric Service Area Results from the 2021 Michigan Energy Waste Reduction Potential Study

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, except for the DTE Electric Service Area Results from the 2021 Michigan Energy Waste Reduction Potential Study which were prepared by Guidehouse, Inc. ("Guidehouse").

Q11. Did you provide input to the group responsible for conducting the integrated resource planning process?

A11. Yes. As supported by Company Witness Ms. Manning and discussed later in my testimony, I provided information on EWR levels considered in the 2022 IRP.

Q12. Can you describe how your testimony is organized?

A12. My testimony consists of the following five (5) parts:

Part I	EWR program overview
Part II	EWR performance for the period 2009-2021
Part III	EWR assumptions and inputs used in the 2022 IRP
Part IV	EWR levels considered in the 2022 IRP
Part V	EWR costs for pre-approval

<u>Part I: EWR program overview</u>

Q13. What is the purpose of the Company's EWR program?

A13. The Company's EWR program launched in June 2009 as a result of the Clean, Renewable, and Efficient Energy Act, also known as 2008 Public Act (PA) 295. In 2016, PA 342 was signed into law, amending PA 295. The EWR standards in PA 342 maintained the minimum energy savings standards of 1.0% of total annual retail electric sales per year through 2021. Beginning in 2019, the subsequent Commission Order in Case No. U-18262 directed EWR plans to substantially conform to the results of statewide energy efficiency potential studies and to a provider's IRP.

The Company's EWR programs are designed to help reduce customers' energy usage by increasing awareness and adoption of energy saving technologies. 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.

Q14. What is the current status of the Company's EWR program?

A14. The Company has continued to build momentum for its EWR program every year since the initial 2009 launch by expanding the scope of existing programs and adding new program options to the portfolio. DTE Electric's EWR program has historically exceeded the energy saving standards defined in PA 295 and PA 342.

Q15. How often are EWR plans filed and reconciled with the MPSC?

A15. EWR plans are filed every two years and specify program design, offerings, and spend levels. The Company's most recently approved EWR plan, Case No. U-20876, covers the years 2022 and 2023.

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 recent EWR reconciliation, Case No. U-21206, includes results from the 2021 program year.

Q16. Can you summarize the Company's EWR program offerings?

A16. Yes. The Company's EWR programs include offerings available through Residential Programs, Income-Qualified Programs, Commercial and Industrial Programs, Pilot Programs, and Education and Awareness Programs. In addition to the program offerings themselves, DTE Electric's Evaluation, Measurement, and Verification (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.

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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; heating, ventilation, and air conditioning (HVAC); weatherization; lighting; home energy assessments; energy education; behavioral programs; school programs; online marketplace; and direct install programs.
- Income-Qualified programs offer qualified customers recommendations, direct installation of energy efficiency measures, major appliance replacements, weatherization measures, and education designed to assist in reducing their energy use and managing utility costs.
- Commercial and Industrial Programs offer businesses products; services and prescriptive rebates for specific equipment replacement such as lighting, boilers, pumps, and compressors; custom programs providing rebates per kilowatt hour (kWh) of electricity savings for a comprehensive system or industrial process improvement; small business programs; operational programs; energy education, and distributor engagement.
- Pilot Programs focus on new and emerging experimental programs to fit longer-term portfolio needs; test the cost-effectiveness of new technologies; and assess customer adoption of new technologies and market acceptance of existing technologies using new approaches.
- Education and Awareness Programs are designed to raise customer EWR awareness to help save energy and to 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.

Part II: EWR performance for the period 2009-2021

Q17. What is the Company's progress towards delivering EWR savings since 2009?

A17. Since the portfolio's inception in 2009, the Company has provided robust EWR programs to help customers reduce energy waste. However, it took time to develop and implement programs that deliver the high levels of energy savings the Company has recently achieved. The Company refined its programs over the years to target increasing levels of energy savings from 0.3% in 2009 to 1.15% in 2016. The Company increased the level of energy savings 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.

Q18. What is the Company's EWR performance from 2009 through 2021?

A18. Table 1 below details the Company's 2009-2021 EWR program performance. Column 2 shows the annual verified net energy savings (MWh) for 2009 through 2021. Column 3 provides the annual percent energy savings per year. Column 4 shows the annual verified net capacity savings (MW) for 2009 through 2021. Column 5 provides the annual spend (including the financial performance incentive) for 2009 through 2021. Lastly, Column 6 provides the dollars per first year MWh saved.

Table 1: Annual Energy, Annual % Savings, Capacity Savings, and Spend

(1)	(2)	(3)	(4)	(5)	(6)
Year	Annual Verified Net Energy Savings (MWh)	Annual % Energy Savings	Annual Verified Net Capacity Savings (MW)	Spend ($MM) [3]	$/MWh ($)
2009	202,718[1]	0.42%	19[1]	$23	$114
2010	402,995[1]	0.89%	45[1]	$47	$118
2011	519,262[2]	1.15%	69[1]	$65	$125
2012	610,655	1.34%	83[1]	$80	$131
2013	613,527	1.30%	84[2]	$86	$140
2014	681,638	1.42%	96[2]	$97	$143
2015	620,850	1.28%	81[2]	$100	$161
2016	630,920	1.31%	106	$102	$162
2017	761,630	1.57%	116	$110	$145
2018	727,907	1.55%	115	$128	$176
2019	717,072	1.53%	127	$130	$182
2020	769,790	1.67%	120	$155	$201
2021	944,217	2.06%	152	$217	$230

[1]Audited Gross Savings [2]Verified Gross Savings [3]Includes financial performance Incentive

Part III: EWR Assumptions And Inputs Used In The 2022 IRP

Q19. What data source did the Company use to model EWR savings in the 2022 IRP?

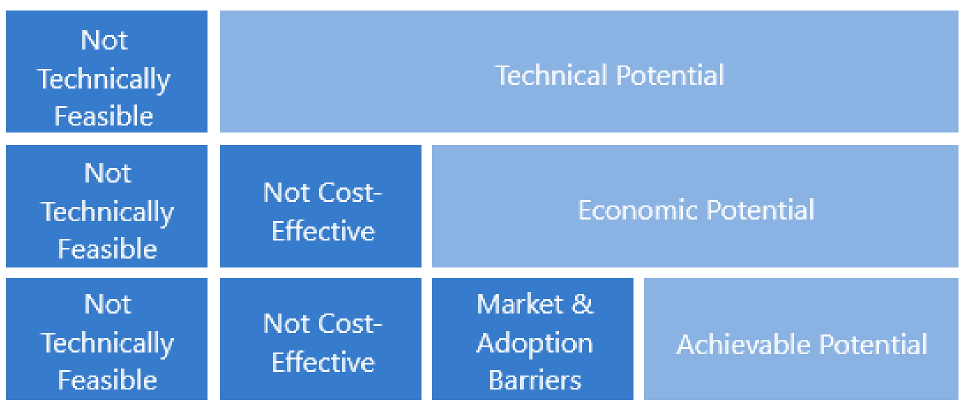
A19. The Company used the 2021 Michigan Energy Waste Reduction Statewide Potential Study[1] ("Statewide Potential Study") as a roadmap for identifying the amount of achievable energy savings potential in its service territory. Public Act 341 of 2016 requires the MPSC to periodically conduct EWR potential studies to

[1] MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

support modeling scenarios and assumptions used by electric utilities in IRPs. In 2020, the MPSC engaged Guidehouse to prepare the Statewide Potential Study for electricity and natural gas in the Michigan Lower and Upper Peninsulas over a 20-year forecast horizon from 2021 to 2040.

The Statewide Potential Study distinguishes between several types of savings potential including technical potential, economic potential, and achievable market potential. Figure 1 provides a graphical representation of the relationship of the various definitions of EWR potential. The Company used the achievable market potential to model EWR opportunity in its IRP. Additional detail on each type of savings potential can be found in the Statewide Potential Study.

Figure 1: Types of Energy Efficiency Potential



Q20. What was the objective of the Statewide Potential Study?

A20. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, including small commercial, multifamily and income-qualified segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was used by Guidehouse to calculate technical, economic, and achievable market potential across utility service areas in Michigan for more than 600 measure permutations. Results are intended to inform EWR goal setting and associated program design for the MPSC.

Q21. Is the Statewide Potential Study an appropriate data source to use in the 2022 IRP?

A21. Yes. In the May 26, 2022 Order in the instant case, U-21193[2], the Commission found that the Company's use of the 2021 Michigan Energy Waste Reduction Statewide Potential Study, rather than the previous 2017 Michigan Energy Efficiency Potential Study, is reasonable. The Commission further found that use of the Statewide Potential Study allows for the most recent data to be used in the Company's IRP and provides more relevant information for modeling purposes.

Q22. What EWR potential was identified for the Company's service area based on the Statewide Potential Study?

A22. After the completion of the Statewide Potential Study, Guidehouse offered utilities the option to receive extrapolated service area-specific results from the study. Exhibit A-8.2 provides a summary of the EWR savings potential identified for the Company's service area based on the Statewide Potential Study as extrapolated by Guidehouse.

Q23. How did the Company model EWR savings based on the Statewide Potential Study?

[2] Case No. U-21193, Order dated May 26, 2022, pg. 3

A23. The Company modeled EWR savings by end-use. End-use is a category of equipment or service that consumes energy (e.g., lighting, refrigeration, heating, cooling, etc.). Modeling by end-use provides a more accurate analysis of EWR as a resource, compared to using levelized averages, and allows for the identification of impacts from specific programs. This method also allows the Company to utilize end-use load shapes, develop more accurate cost assumptions, and calculate better lifetime savings estimates.

The end-uses used in the Statewide Potential Study include the segments listed in Table 2, below:

Table 2: End-Use Types

Residential End-Uses	Commercial End-Uses	Industrial End-Uses
Appliance	Cooking	Lighting
HVAC	HVAC	Refrigeration
Lighting	Lighting	Machine Drive
Other	Other	Whole Building
Water Heating	Water Heating	
Whole Home	Whole Building	
	Refrigeration	

The Company maximized the achievable market savings potential from each end-use for most EWR sensitivities[3].

Q24. How did the Company define the amount of EWR savings potential available for each end-use?

[3] The exception includes the 1.50% sensitivity (EWR sensitivities are discussed in Section IV of my testimony) in years 2024, 2025, 2032, and 2034 through 2039. For these few exceptions, the EWR modeling process began with a foundational level of savings for each end-use that is reflective of the Company's actual operational experience. The foundational level of savings was informed by the Company's historical savings by end-use and savings potential limits. EWR savings beyond the foundational level were modeled by adding the least cost end-use savings until the targeted savings level was met.

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A24. The EWR savings available for each end-use were determined by the achievable incremental annual savings based on the Statewide Potential Study. Incremental annual savings represent the first-year savings potential that is available in any given year. In addition, the Company added incremental annual savings from re-participation. The treatment of savings from re-participation is further described below:

> *Re-participation:* Section 7.6 of the Statewide Potential Study assumes that 100% of program participants re-adopt energy efficient measures after the end of the efficient measure's expected useful lifetimes. This implies that measures that met the end of their useful life do not incur incentive costs when replacing incumbent equipment that was already updated to efficient equipment during the study horizon. Therefore, incremental savings in the Statewide Potential Study account only for new program participants, and these savings are summed up year-over-year to represent cumulative potential.

Although this approach, as described in the Statewide Potential Study, accurately reflects the cumulative impact of EWR savings on sales, it does not reflect the annual incremental savings that serve as the basis for EWR Plan filing targets. Customers that participate in EWR programs can participate again as the technology reaches the end of its useful life. By adding savings and associated costs from re-participation customers into the modeling of EWR inputs, the Company reflects incentive costs and incremental annual savings that are better aligned with EWR targets and budget setting.

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Q25. Do any of the EWR sensitivities require savings levels that exceed the incremental annual achievable potential savings identified in the Statewide Potential Study?

A25. Yes. All of the EWR sensitivities other than the Reference sensitivity require saving levels that exceed the incremental annual achievable potential savings identified in the Statewide Potential Study in some or all years of the IRP timeframe.

Q26. How did the Company model EWR savings greater than the incremental annual achievable potential savings identified in the Statewide Potential Study?

A26. For EWR levels that required savings above the incremental annual achievable potential savings identified in the study, the portfolio average[4] was scaled up in early years and then transitioned to unidentified future technologies in later years to fill the savings gap. Table 3 shows which assumption was used to fill the savings gap between the achievable potential and any savings target level by year for the applicable sensitivity.

Table 3: Energy Savings Gap Assumption

	2024	2025	2026	2027	2028	2029-2042
Portfolio Average	100%	100%	75%	50%	25%	0%
Unidentified Future Technologies	0%	0%	25%	50%	75%	100%

[4] The Residential Whole Home end-use was excluded from the portfolio average calculation as it primarily includes Home Energy Reports which have a one-year measure life.

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This method to fill the savings gap to the target levels was discussed with Guidehouse as an appropriate proxy. Using the portfolio average initially to fill the savings gap keeps the portfolio balanced so there is equitable savings from EWR programs across customer types and measures. Starting in 2026, unidentified future technologies are phased into in Statewide Potential Study. Unidentified technology estimates are high level and meant to represent the directional probability of unknown technology contributions to potential savings. The Company expanded these assumptions to help fill the savings gap starting in 2026.

Q27. Did the Company apply Installation Rate Adjustment Factors (IRAF) to the EWR potential savings?

A27. Yes. The Statewide Potential Study accounted for Net-to-Gross (NTG) adjustments but did not include adjustments for IRAF. Whereas NTG adjusts for free-ridership (i.e., customer would have taken efficient action without the EWR program) and spillover (i.e., additional efficient actions taken because of the EWR program), IRAF accounts for measures that may be removed or never installed or if measures are operating as expected. To adjust for these factors, the Company applied IRAF values to the incremental annual savings potential to calculate potential net verified EWR savings[5] available for each end-use. This was done by using the most recent IRAF values available at the time of the model development and determined by the Company's third-party evaluator. The application of IRAF better reflects the annual incremental savings that serve as the basis for EWR Plan filing targets.

[5] The Company is required to report verified net savings in EWR plan filings and reconciliations.

Q28. How did the Company estimate the measure life of energy savings identified in the Statewide Potential Study?

A28. The 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 (e.g., light bulbs burn out, lighting systems must be upgraded, and HVAC equipment must be replaced).

Guidehouse provided the weighted average measure life, by year, for all 17 end-uses categories identified in the Statewide Potential Study. Exhibit A-8.2 provides the measure life for all six residential end-uses and all seven commercial and four industrial end-uses. The Company used these weighted average measure lives for each end-use, by year, to calculate lifetime savings. This approach allowed the Company to capture the effects of a changing measure mix over the IRP planning period and more accurately accounts for the cumulative impact of EWR savings.

Q29. Did the Company consider the load shape of EWR measures when developing hourly savings units?

A29. Yes. For residential end-uses, the Company used load shapes recently developed for integration in the Michigan Energy Measures Database (MEMD). For commercial and industrial end-uses, the Company used load shapes developed by Guidehouse in 2018 and applied in the 2019 IRP. Updated commercial and industrial load shapes were not available at the time of the EWR model development.

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 blended the end-use savings shapes to develop a combined EWR savings shape that could be used in IRP modeling.

Q30. Did the Company include line losses in its modeling of EWR savings?

A30. Yes. Since EWR savings are modeled at the end-use level, 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 & McDonell line loss estimates for DTE Electric's system.

Q31. What are EWR end-effects?

A31. EWR end-effects are used to account for the EWR benefits that occur after the IRP study period ends. The entire cost of the EWR measures is accounted for in the IRP timeframe but some of the benefits go beyond the end of the timeframe due to the measure life of EWR technologies. The EWR end-effect values represent the portion of benefits that occur outside of the IRP timeframe.

Q32. Did you provide any inputs for EWR end-effects to the IRP team?

A32. Yes. For each level of EWR, the total present value (PV) benefits were provided to the IRP team as well as the amount of PV benefits through 2042, as discussed by Witness Manning. An output of the cost-effectiveness software used, DSMore[6], is

[6] Demand Side Management Option/Risk Evaluator

the PV total benefits for the entire life of each end use as well as individual year benefits for the first 25 years. The PV of the first 20 years was calculated and provided to the IRP team so it can be compared to the PV total benefits.

Q33. What data source did the Company use to model EWR costs?

A33. The Company used the underlying cost assumptions included in the Statewide Potential Study. The cost per first year saved was provided for each end-use by year. The Company aggregated the total costs for each end-use to calculate program costs. Exhibit A-8.2 provides cost per first year saved for each end-use by year.

Q34. Did the Company model any alternative EWR costs?

A34. Yes. Michigan Integrated Resource Planning Parameters (MIRPP) requirements[7] for the Emerging Technology scenario require that EWR incentive costs be reduced by 35% for certain savings levels compared to those used in the Statewide Potential Study. In these cases, the Company analyzed alternative costs that align with the inputs and assumptions used in the underlying EWR model.

Q35. Did the Company include any other costs in its modeling of EWR that are in addition to costs provided in the Statewide Potential Study?

A35. Yes. The Company also included costs associated with pilots (5% of the total annual spend8), education (3% of the total annual spend), EM&V (based on the 2022-2023 EWR planned spend and scaled proportional to savings), and the financial performance incentive (20% of total annual spend).

[7] MPSC Case No. U-18418 Order, November 21, 2017
[8] In 2023, 6% was used for pilots in line with the EWR 2022-2023 Plan, Case No. U-20876

Part IV: EWR levels considered in the 2022 IRP

Q36. What were the EWR levels the Company evaluated as part of its IRP process?

A36. In total, six EWR levels were evaluated. The EWR levels as a percent of total annual retail electric sales include:

1) Potential Study level[9] – Developed based on the levels identified in the Statewide Potential Study
2) 1.50% level[10] - Required based on the MIRPP requirements
3) 2.00% level[11] - Required based on the MIRPP requirements
4) 2.50% through 2032 level[12] - Developed through the stakeholder collaboration process
5) 2.50% level[13] - Required based on the MIRPP requirements
6) 3.00%[14] - Developed through the stakeholder collaboration process

Incremental changes in EWR from the Potential Study level are evaluated through the IRP modeling process and further explained by Company Witness Manning.

Q37. Can you briefly summarize the information in Exhibit A-8.1?

A37. Exhibit A-8.1, lines 1 through 6, show the estimated annual savings (MWh) for each EWR level for 2023 through 2042. The EWR target for each level was

[9] Potential Study level has a target of 2% EWR in 2023 to align with the approved 2022-2023 EWR Plan, Case No. U-20876, and then maximizes potential starting in 2024

[10] 1.50% level has a target of 2.00% EWR in 2023 to align with the approved 2022-2023 EWR Plan, Case No. U-20876, and targets 1.50% EWR starting in 2024

[11] 2.00% level has a target of 2.00% EWR for the entire IRP time frame

[12] 2.50% through 2032 level has a target of 2.00% EWR in 2023 to align with the approved 2022-2023 EWR Plan, Case No. U-20876, targets 2.50% EWR in 2024 through 2032, and then maximizes potential starting in 2033

[13] 2.50% level has a target of 2.00% EWR in 2023 through 2025, and then targets 2.50% EWR starting in 2026

[14] 3.00% level has a target of 2.00% EWR in 2023 to align with the approved 2022-2023 EWR Plan, Case No. U-20876, and targets 3.00% EWR starting in 2024

calculated as the percent annual savings multiplied by the total retail electric sales from the previous year. Lines 7 through 12 provide the estimated cumulative energy savings (MWh) for each EWR level for 2023 through 2042. Lines 13 through 18 provide the estimated cumulative capacity savings (MW) for each EWR level for 2023 through 2042. Lines 19 through 24 provide the total annual O&M cost for each EWR level for years 2023 through 2042. Lines 25 through 30 provide the total financial performance incentive for each EWR level for years 2023 through 2042. Lastly, lines 31 through 36 provide the total annual cost for each EWR level for years 2023 through 2042.

Q38. Did the Company determine the cost-effectiveness for each level?

A38. Yes. Table 4 below provides the Utility System Resource Cost Test (USRCT) results for each EWR level.

Table 4: USRCT Benefit Cost Ratio Results

1.50% EWR	Potential Study	2.00% EWR	2.5% (2033) EWR	2.50% EWR	3.00% EWR
1.31	1.42	1.13	1.12	1.02	0.95

Q39. Why does the Company use the USRCT for determining cost-effectiveness?

A39. Section 73(2) of Michigan Public Act 342 of 2016 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, subject to section 78, is reasonable and prudent." Therefore, the Company uses the USRCT for determining cost-effectiveness in EWR plan filings.

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Q40. Did the Company include avoided transmission and distribution (T&D) costs in its EWR cost-effectiveness testing?

A40. Yes, Witness Musonera provided an estimate of the deferred T&D costs that were incorporated into the EWR cost-effectiveness testing. The assumptions are detailed in her Exhibit A-13.2.

Q41. What level of EWR did the Company include in its Proposed Course of Action (PCA)?

A41. The Company's PCA maximizes the market achievable potential identified in the Statewide Potential Study. The level of EWR savings in the PCA includes 2.0% in 2023 and average annual savings of 1.5% throughout the IRP timeframe. The effect of Potential Study level of EWR savings on the PCA and how the IRP modeling results were used to develop the PCA is discussed in the testimony of Witness Manning.

Q42. What confidence does the Company have in achieving the energy savings level identified in the Statewide Potential Study?

A42. The Company believes the assumptions included in the achievable market potential are reasonable. However, given the uncertainties in the potential energy savings, the Company will continue to evaluate the potential energy savings as part of future IRP proceedings, and may seek to adjust the level of energy savings as necessary.

The Statewide Potential Study is an estimate of future energy efficiency savings. Like any estimate, there is an implied level of uncertainty around each predicted value. This uncertainty includes changes in baseline standards, technology, forecasted avoided costs, and projected customer response and behavior. Similarly, Guidehouse included an estimate of unidentified future technology emergence within its calculation of achievable market potential beginning in 2026 and accelerating through the study horizon. These estimates are high level and are meant to represent the directional probability of unknown technology contributions to achievable market potential. The addition of these assumptions add uncertainty to later year results.

Q43. What challenges will impact the Company's ability to deliver EWR savings?

A43. The Company is forecasting energy savings aligned with the Statewide Potential Study that average 1.50% annual savings throughout the IRP study period. Achieving savings identified in the Statewide Potential Study will become increasingly difficult as the Company faces challenges such as:

- Lighting has been the primary source of low-cost electric energy savings for more than a decade. The Company has been actively reducing its reliance to on lighting as a source of energy savings; however, a recent Department of Energy (DOE) ruling[15] eliminates the savings potential for most residential lighting products. Its elimination will have implications for the continued ability to continue achieving high electric savings targets
- As demonstrated in Table 1, Column 6, the cost per first year MWh achieved has increased over time and is expected to continue this trend
- Utilities have been actively researching, testing, and experimenting with emerging technologies, but there are limited options to replace lighting

[15] Appliance Standards Rulemakings and Notices (energy.gov)

- Customer baseline installed efficiency keeps rising as energy efficiency programs and other factors make customers more energy-conscious. This could also decrease NTG ratios as free-ridership increases
- Pressure on customer affordability as EWR savings reduce consumption and therefore a lower sales volume to allocate cost over
- Increasing EWR costs associated with higher energy saving targets adds to customer affordability pressure. For example, the shift towards more commercial and industrial savings has led to significant increases in EWR surcharges for that customer segment with few customers within that segment directly benefiting

Q44. Do the EWR levels in the 2022 IRP consider the effects of the recently passed Inflation Reduction Act?

A44. No. It is too early to project the specific grant dollars that will be available to Michigan (and the extent to which the tax credits will be utilized by Michigan entities) served by DTE Electric and the resulting net impacts on EWR potential. While the Inflation Reduction Act (IRA) and associated funds will likely help drive the uptake of energy efficiency measures, it is unclear how the IRA will affect the results of the 2021 Statewide Potential Study[16]. There will be expanded energy efficiency investments resulting in energy savings, but it is unclear how these may impact electric savings opportunities from utility programs and considering such factors as increases in the baseline efficiency of installed equipment and decreasing Net-to-Gross (NTG) ratios (driven by increases in free-ridership). Fully

[16] For example, the clean energy and efficiency incentives for residential and commercial individuals amount to $4B per year nationally, but it is unclear what portion would be used by Michigan and specifically for measures impacting electric loads since there is little electric space heating in Michigan.

understanding the impacts on the long-term opportunities for utility driven energy efficiency improvements and net EWR savings will take time, especially since the specific guidance and rules are yet to be developed[17]. While the legislation will affect the energy efficiency landscape in Michigan, it is too early to quantify the impacts, let alone develop long-term plans and forecasts upon net-utility EWR program savings. It is reasonable that these IRA-driven opportunities will be captured in subsequent EWR Potential Studies and IRPs.

In addition, the Emerging Technology scenario includes a 35% reduction to EWR incentive costs in the 2021 Statewide Potential Study. While this scenario is not intended to explicitly represent the impacts of the IRA, the results of the scenario and associated sensitivities provide a range of possibilities in which the IRA impacts may potentially fall.

Part V: EWR costs for pre-approval

Q45. Is the Company requesting pre-approval of the projected costs to deliver these energy savings levels as part of this proceeding?

A45. 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 every two years.

[17] For example, energy efficiency rebates available through the HOMES rebate program (Sec 50121) will be administered through State Energy Offices. There are multiple requirements to qualify, and the specific guidance and rules are under development. Similarly, the regulations and guidance for the $36M annually (nationally) in energy efficiency tax credits available to commercial buildings (Sec 13303) are yet to be developed by the Secretary. See, e.g., U.S. Department of Treasury October 5, 2022 notices seeking comments on the implementation of certain provisions, including energy efficiency tax credits. Available at: IRS asks for comments on upcoming energy guidance | Internal Revenue Service.

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Q46. Will the Company refine its EWR cost projections in future EWR Plan filings?

A46. 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.

Q47. When is the next required EWR Plan filing?

A47. The Company will file its next EWR Plan on July 1, 2023, for the period 2024 through 2025.

Q48. 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?

A48. 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.

Q49. Does this complete your direct testimony?

A49. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

VIELKA M. HERNANDEZ

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF VIELKA M. HERNANDEZ

Line No.

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

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

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your current position with the Company?

A3. My title is Manager, Renewable Energy Strategy.

Q4. What is your educational background?

A4. I graduated from Georgetown University's Edmund A Walsh School of Foreign Services in 2007 with a Bachelor of Science Degree in International Economics. In 2016, I received a Master of Business Administration from the Georgetown University McDonough School of Business.

Q5. What is your work experience?

A5. I began my career in 2007 in Fannie Mae's Controllers Associate Rotational Program, where I completed three six-month rotations through the Financial Controls and Systems, Multifamily CFO, and Independent Price Verification teams. After graduating early from the Associate Program, I joined the Independent Price Verification team as a Pricing Analyst in 2009 and was promoted to Senior Pricing Analyst in 2011. In 2014, I joined Fannie Mae's Enterprise Risk Management team as a Senior Risk Analyst.

My employment with DTE Energy began in 2016 when I joined the Master of Business Administration (MBA) Leadership Development program - a three-year rotational program between the Corporate Strategy and Corporate Finance and Development teams. In this role I developed financial models for potential investments and projects to help inform Senior Management decision. I joined the Renewable Energy team within DTE Electric in 2019 as a Marketing Program Manager and was promoted to Manager of Strategy and Special Projects in April 2021.

Q6. What are your duties and responsibilities in your current position?

A6. As a member of the Renewable Energy Strategy team, I support activities related to maintaining the Renewable Portfolio Standard (RPS) compliance, executing Request for Proposals (RFPs) for renewable energy projects and filing applications with the Michigan Public Service Commission (MPSC).

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission?

A7. Yes, I have sponsored testimony in the following cases:

U-20723	2019 Renewable Energy Plan (REP) Reconciliation
U-18091	Public Utilities Regulatory Policies Act (PURPA)
U-21010	2020 REP Reconciliation
U-21285	September 2022 Amended Renewable Energy Plan

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to:

- Discuss the Renewable Portfolio Standard (RPS) requirements, related to Michigan PA 295 of 2008, as amended by PA 342 of 2016;
- Discuss the Voluntary Green Pricing (VGP) program to include product offerings, sales forecast, and associated plan to meet customer demand;
- Describe the National Renewable Energy Laboratory's (NREL) class used to develop the forecasts and assumptions used for developing or purchasing energy from utility-scale renewable energy resources in the Integrated Resource Plan (IRP) process;
- Describe the utility-scale wind and solar energy resources included in DTE Electric's IRP process, and proposed course of action (PCA);
- Discuss the potential for the Company to request a Financial Compensation Mechanism (FCM);
- Describe the Company's 2022 requests for proposal (RFP) for renewable energy resources.

Q9. Are you sponsoring any exhibits in the proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-9	Summary of Renewable Resources
A-9.1	2022 DTE Electric Renewable Energy Solar RFP Overview Document

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A-9.2 2022 DTE Electric Renewable Energy Wind RFP Overview Document

A-9.3 2022 RFP Results

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. Did you provide inputs to the group responsible for conducting the IRP modeling process?

A11. Yes. As further described by Company Witness Manning and discussed later in my testimony, I provided DTE Electric's approved RPS and VGP renewable energy build plan through 2025 included in the IRP starting point as well as the NREL class used to forecast pricing and capacity factor data for new renewable energy builds as published by NREL in the 2021 ATB Data report[1].

Q12. How is your testimony organized?

A12. My testimony consists of the following seven (7) parts:

Part I Statutory Renewable Portfolio Standard and Clean Energy Goal

Part II Approved Utility-Scale Wind and Solar Energy Resources included in the IRP starting point

Part III Utility-Scale Wind Costs

Part IV Utility-Scale Solar Costs

Part V Utility Scale Renewable Energy included in the PCA

Part VI Financial Compensation Mechanism

[1] 2021 NREL Electricity Annual Technology Baseline (ATB) Data Download. Accessed January 20, 2022, from https://atb.nrel.gov/electricity/2021/data

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Part VII Request for Proposals for Renewable Energy Resources

Part I: STATUTORY RENEWABLE PORTFOLIO STANDARD AND CLEAN ENERGY GOAL

Q13. What are the current requirements of Michigan's renewable portfolio standard (RPS)?

A13. In December 2016, the Michigan Legislature enacted Public Act (PA) 342, which amended PA 295 of 2008. The new law outlines updated requirements for renewable energy in Michigan. Under the new law, the Company's "renewable energy credit portfolio" shall consist of 10% renewable energy credits, as were required under former Section 27 of 2008 PA 295 through 2018. In 2019 and 2020, a "renewable energy credit portfolio" shall consist of at least 12.5%, and in 2021, at least 15% renewable energy credits. MCL 460.1028(1). For DTE Electric, the RPS is calculated using the number of weather-normalized megawatt hours of electricity sold by the electric provider during the previous year to retail customers in Michigan. MCL 460.1028(2). Compliance with the RPS is addressed through the Company's renewable energy plan (REP) approved by the Commission pursuant to Case No. U-20851 and also in the Company's Amended REP filed on September 30, 2022, under Case No. U-21285.

Q14. How do the renewable resources receive credit under the Renewable Portfolio Standard?

A14. Renewable Energy Credits (RECs) are the primary vehicle for complying with the renewable energy credit standards and are measured in megawatt-hours produced by qualifying renewable energy systems, where one megawatt-hour equals one

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REC. Electric providers may also purchase or otherwise acquire qualifying RECs with or without the bundled renewable energy.

Additional "Michigan Incentive" RECs may be awarded for the following:

- One tenth (1/10) of a REC, during the first three years of production, for energy generated from renewable energy systems built with Michigan equipment or labor;
- One fifth (1/5) of a REC for energy generated during peak periods by renewable energy systems other than wind or for renewable energy generated and stored during off-peak usage periods in advanced electric or hydroelectric pumped storage facilities and used during peak usage periods;
- Two (2) incentive RECs for electricity from solar power that was approved in a renewable energy plan before the effective date of the 2016 amendatory act.

By the last day of each calendar year, an electric provider must retire the number of RECs required for compliance using the Michigan Renewable Energy Certification System (MIRECS) database.

Q15. Are there any other goals included in PA 342 related to the renewable energy?

A15. Yes. Section 1(3) of PA 342 indicates the state has a goal that "not less than 35% of this state's electric needs should be met through a combination of energy waste reduction and renewable energy by 2025…." Renewable energy that counted toward the renewable energy standard on the effective date of PA 342, as well as RECs granted for renewable energy investments after that date, including RECs generated pursuant to Section 6 of 2016 PA 341 (voluntary green programs) are counted toward the goal. Energy waste reduction measures that resulted in annual electricity savings measured since October 6, 2008, as recognized by the commission through annual Energy Waste Reduction (EWR) reconciliation proceedings, also count toward achieving the 35% goal (Section 1(3)(b) of PA 342).

Q16. Can you address the provisions in PA 342 that require utilities to establish VGP programs?

A16. Section 61 of PA 342 states, "An electric provider shall offer to its customers the opportunity to participate in a voluntary green pricing program under which the customer may specify, from the options made available by the electric provider, the amount of electricity attributable to the customer that will be renewable energy." DTE Electric has established approved offerings through the subsequent Section 61 filings. Additionally, the assets serving Section 61 programs have been approved through Amended Renewable Energy Plan filings.

Q17. Has the Company made any other renewable energy goals outside of the PA 342 framework?

A17. Yes. In May 2018, DTE Electric established a Clean Energy goal of at least 50% clean energy by 2030, achieved through a combination of investments in at least 25% renewable energy, and the remaining through energy waste reduction.

<u>PART II: APPROVED RENEWABLE ENERGY RESOURCES INCLUDED IN THE IRP STARTING POINT AND IRP PROCESS</u>

Q18. How are the existing and/or previously approved renewable energy resources modeled in the starting point of the IRP categorized?

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A18. The renewable resources included in the IRP modeling starting point are categorized based on the Company's renewable energy commitments:

- Prior approved resources to meet the PA 342 RPS of 15%
- Prior approved VGP resources

Exhibit A-9 details the renewable resources that comprise each of the Company's existing renewable commitments. Details on the IRP modeling starting point are addressed by Witness Manning in her testimony.

Q19. In total, what are the Company's existing renewable resources in service to comply with PA 342's RPS requirements?

A19. Today, DTE Electric has approximately 1,327 MW of owned or contracted qualifying renewable energy resources comprised of wind, solar, biomass and landfill gas in service or expected to be in service this year to comply with PA 342's RPS requirements. These projects are detailed on lines 3 through 52 of Exhibit A-9. The resources are comprised of approximately 781 MW of Company-owned wind, approximately 458 MW of contracted wind, over 65 MW of Company-owned solar, approximately 17 MW of contracted biomass, and approximately 6 MW of contracted landfill gas.

Q20. What are the Company's existing wind resources in service to comply with PA 342's RPS requirements?

A20. DTE Electric currently owns and operates twelve wind parks with a combined nameplate capacity of approximately 1,236 MW, of which 781 MW is used to comply with PA 342's RPS requirements. The nameplate capacities of the parks range from 14 MW to 200 MW and the fleet is comprised of 567 wind turbine generators, of which 410 wind turbine generators are used to comply with PA 342's RPS requirements. DTE Electric also has six Power Purchase Agreements (PPAs) with a combined nameplate capacity of 458 MW.

Q21. What are the Company's expected remaining wind resources necessary to comply with the PA 342 RPS requirements?

A21. In July 2020, the Commission approved the turbine supply agreements and engineering, procurement, and construction contracts for Meridian Wind Park, 225 MW in Midland and Saginaw counties. The wind park is expected to reach commercial operation in late 2022. With the addition of the Meridian Wind Park, the Company expects to have sufficient renewable energy credits to achieve and maintain compliance with PA 342 RPS requirements.

Q22. What are the Company's solar resources in service to comply with PA 342's RPS requirements?

A22. DTE Electric's first solar assets were developed as part of the SolarCurrents pilot program. SolarCurrents included customer-owned distributed generation solar and utility-owned solar, in which DTE Electric developed larger projects, which feed into the grid. SolarCurrents is a Commission-approved solar pilot program. The program includes approximately 7 MW of customer-owned distributed generation and over 14 MW of utility-owned solar facilities. The customer-owned program began with an initial offering of 5 MW in the first phase and concluded with a second phase of 2 MW. DTE Electric utilizes the RECs associated with this program by aggregating the participating customers' meter data; customer generation is grouped together to account for each REC.

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The utility-owned component of SolarCurrents consists of over 14 MW of nameplate capacity at 28 sites throughout the DTE Electric service territory. DTE Electric utilized the SolarCurrents pilot to gain experience in large solar developments through relationships with solar manufacturers, distributors, and contractors. The Company constructed solar projects using various photovoltaic (PV) panel technologies and approaches. Individual project sizes range from less than 100 kW to over one MW. The architectures of the sites vary from site to site and include ground-mount, roof-mount, and carport.

Beyond SolarCurrents, DTE Electric developed a 50 MW solar project that achieved commercial operation in 2017. This project consists of three sites: the 28 MW Demille Park, the 20 MW Turrill Park, both located in Lapeer, MI, and the 2 MW of solar located at O'Shea Park in Detroit, MI. This 50 MW collectively was dedicated to the MIGreenPower VGP program, although any unsubscribed portions counted toward the RPS. In June 2021, the Commission approved a partial settlement agreement in Case No. U-20713 allowing DTE Electric to transition the 50 MW from Demille Park, Turrill Park, and O'Shea Park to RPS compliance assets while transitioning Assembly Solar PPA, 79 MW, to the MIGreenPower VGP program. Including utility-owned SolarCurrents projects, the Company has over 65 MW of Company-owned solar in service and has 79 MW of contracted solar in service. The Company-owned solar is used to comply with PA 342's RPS compliance and the contracted solar is used for DTE Electric's MIGreenPower VGP program.

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Q23. What are the Company's expected remaining solar resources necessary to comply with PA 342's RPS requirements?

A23. The Company's remaining solar resources necessary to comply with PA 342's RPS requirements is Riverfork PPA (49 MW), which we expect to come online in 2023 and a Solar Pilot (10 MW) expected to come online in 2024. The Riverfork PPA was expected to be in service by the fourth quarter of 2022, but has been delayed until the fourth quarter of 2023.

Q24. Do the renewable resources included in the 2022 IRP modeling starting point achieve the 15% RPS?

A24. Yes, the wind and solar, as well as several biomass and landfill gas resources included in the 2022 IRP modeling starting point achieve the 15% RPS and are included in the IRP scenarios as discussed in the testimony of Witness Manning.

Q25. In total, what are the Company's existing renewable resources included in the REP that currently serve the VGP program?

A25. The VGP assets in service are shown on lines 58 through 61 in Exhibit A-9, totaling 535 MW are also included in the REP, and any unsubscribed portions can count toward RPS compliance.

Q26. What other renewable resources beyond the existing 15% RPS renewable resources are included in the starting point of the IRP?

A26. In addition to the renewable resources approved to comply with PA 342's 15% RPS, the Company included approved future VGP resources, namely Calhoun Solar PPA (100 MW), Freshwater Solar (200 MW), White Tail Solar (120 MW), and generic solar builds of 162 MW in 2023, 183 MW in 2024, and 132 MW in 2025. These VGP resources were approved in Case No. U-20713. The Calhoun Solar PPA was expected to be in service by the fourth quarter of 2022, but has been delayed until the fourth quarter of 2023. Freshwater Solar and White Tail Solar were both expected to be in service by fourth quarter of 2022, but Freshwater Solar has been terminated and White Tail Solar has been delayed indefinitely. Replacements for these projects were approved by the MPSC in Case No. U-20851. Given the delays associated with Freshwater Solar and White Tail Solar, we modeled these resources for 2025 and 2024 respectively, so no changes to the modeling are necessary due to the replacement of the projects.

Q27. Were there any additional VGP projects considered in the IRP modeling?

A27. The IRP starting point does not include any additional VGP projects beyond the amounts already approved by the Commission. Three sensitivities with additional VGP projects were analyzed as part of the IRP modeling given the strong interest by customers in the program. One sensitivity modeled an additional 440 MW of solar that is approved for the City of Ann Arbor with a contingency of executing a special contract. The second sensitivity modeled an additional 650 MW of solar included in DTE Electric’s 2022 amended REP, which the Company filed on September 30, 2022, in Case No. U-21285. The third sensitivity, submitted by a stakeholder, increased VGP projects to 912 MW wind and 758 MW solar by 2025. Refer to the testimony of Witness Manning for detail on the IRP sensitivities.

Q28. Does the Company continue to see customer demand in the MIGreenPower VGP program?

A28. Yes. As of September 30, 2022, the Company has seen non-contracted participation of 68,543 total customers and 152,387 MWh annually.

The Company has also seen demand for contracted (procuring over 2,500 MWh per year) participation from commercial and industrial customers. DTE Electric currently has 57 signed customers and 2,380,352 MWh annually as shown in Table 1.

Table 1: Contracted VGP Interest

	Contracted Customers	Contracted MWh
Currently Enrolled	14	955,105
Waitlisted	43	1,425,247
Total	**57**	**2,380,352**

Q29. What MIGreenPower product offerings are available for customers desiring to attribute a greater percentage of their electric consumption to renewable energy sources?

A29. The Company offers Rider 17, MIGreenPower, for all full-service customers who desire to have a greater portion of their electric use attributed to renewable resources and who want to encourage additional development of Michigan-based renewable energy resources. Customers participating in this program can choose up to 85% of their electric usage, in 5% increments, to be sourced from MIGreenPower renewable energy resources in addition to the 15% they already receive from the RPS.[2]

[2] Case No. U-21172, filed on August 31, 2022, requests to amend the tariff to allow customers participating in this program to choose up to 100% of their electric usage to be sourced from MIGreenPower renewable energy resources.

Q30. What is the current MIGreenPower VGP program five-year subscription forecast?

A30. The forecast for MIGreenPower is shown in Table 2.

Table 2: MIGreenPower Forecast

Year	Cumulative MWh
2023	3,123,000
2024	4,105,600
2025	5,256,000
2026	6,004,800
2027	6,669,800

Q31. How did the Company establish the forecast for MIGreenPower?

A31. The Company forecasted MIGreenPower enrollments by first considering current enrollments from non-contracted (<2,500 MWh) and contracted (≥2,500 MWh) customers, as well as customer-requested projects. Growth in future non-contracted (enrolling less than 2,500 MWh per year) customer enrollment rates were based on historical customer acquisition rates, plus an expected acceleration in growth due to potentially favorable future net premiums. For contracted (enrolling greater than or equal to 2,500 MWh per year) customers, the Company then forecasted future enrollment levels by considering estimates of future loads and established enrollment levels. The forecasted loads included a 12-month usage for each individual customer segment, with a compounding 2% reduction to account for energy conservation, energy efficiency, customer attrition, and other minor adjustments. We established the customer-requested portion of the forecast based on the number of large customers the Company is currently in discussions with to design and construct dedicated projects. The level of enrollment will be outlined in individual customer-requested contracts; customers participating in this offering are required to subscribe to the output of the project for the life of asset, so these contracts can be considered individually in the forecast.

We derived the proportion of the forecast for prospective contracted customer and customer requested enrollments by applying a factor that accounts for their likelihood to sign a contract based on the stage of negotiations within the sales pipeline. As discussions progress, the likelihood of signing increases, and we include a larger percentage of the contract-specified MWh in the forecast. New leads as well as previous growth patterns were also taken into account during the forecasting process.

Q32. How does the Company plan to meet the demand for the MIGreenPower program?

A32. The Company plans to continue to increase capacity in the MIGreenPower program to satisfy customer demand. In the event that customer demand exceeds program capacity, customers who are interested in the program will be added to a waitlist for enrollment as space becomes available. Issues related to resources used to meet MIGreenPower demand and VGP program design are addressed as part of Section 61 cases and corresponding REP amendment cases, such as the current Case Nos. U-21172 and U-21285.

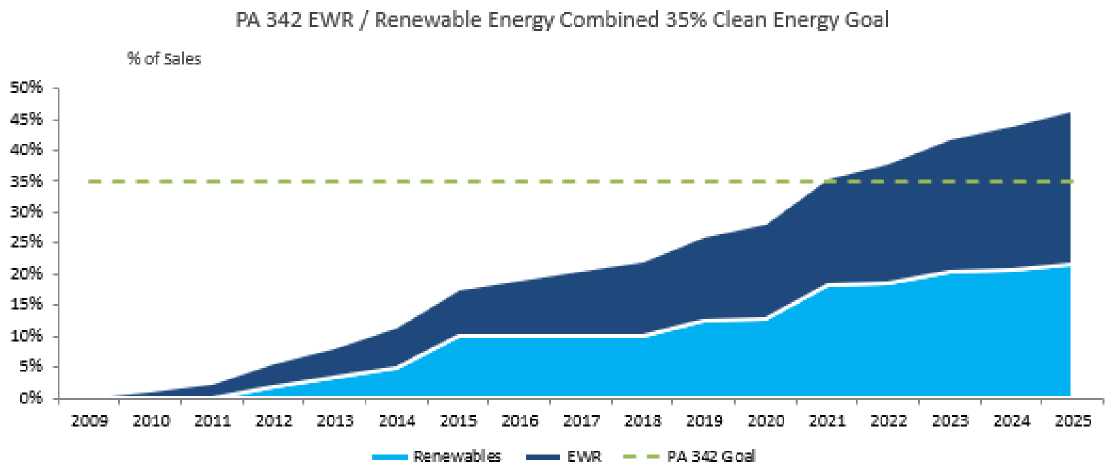
Q33. Is the Company requesting any Commission action with respect to the MIGreenPower program in this IRP proceeding?

A33. No, the MIGreenPower forecast and product offerings are currently being contemplated in Case No. U-21172. Furthermore, the Company filed an Amended REP to incorporate build from a recent customer-requested contract, in accordance with the settlement agreement in Case Nos. U-20713 and U-20851.

Q34. Are the Company's renewable resources included in the starting point paired with energy waste reduction (EWR) likely to support the State's 35% Clean Energy by 2025 goal outlined in Sec. 1 of PA 342?

A34. Yes. As stated in Q24, the Company is currently in compliance and expects to maintain at least 15% of electricity from renewable energy for compliance and an additional 7% from VGP. In addition, the Company expects to have over 24% energy waste reduction by 2025. The Company's EWR targets anticipate approximately 20% in 2022, approximately 22% in 2023, approximately 23% in 2024, and approximately 25% in 2025. Witness Bilyeu discusses the EWR levels considered in this IRP. The Company expects that the combined effect of its renewable energy resources and annual energy waste reduction targets will achieve the 35% goal prior to 2025, as measured from 2009 levels, as illustrated in Figure 1.

Figure 1: PA 342 Clean Energy Goal



Q35. Do the renewable resources and energy waste reduction included in the 2022 IRP modeling achieve the at least 50% clean energy by 2030 goal established by the Company in 2018, which called for at least 25% renewable?

A35. Yes, the renewable energy and energy waste reduction included in the 2022 PCA is forecasted to achieve the 50% Clean Energy goal.

<u>PART III: UTILITY-SCALE WIND COSTS</u>

Q36. Which NREL class was used to forecast wind cost assumptions, wind net capacity factor (NCF) assumptions and wind O&M and capital maintenance assumptions included in the IRP process/modeling?

A36. As described by Witness Cejas Goyanes in his testimony, the Company used Class 8 moderate for wind. NREL 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 as shown in Table 3 below for wind speed in the range of 6.53 - 7.1 m/s the corresponding resource class is class 8.

Table 3: Land-Based Wind Resource Classes[3]

Wind Speed Class	Min. Wind Speed (m/s)	Max Wind Speed (m/s)	Wind Speed Range (m/s)	Percentile Range
1	9.01	12.89	3.88	<1%
2	8.77	9.01	0.24	1% - 2%
3	8.57	8.77	0.2	2% - 4%
4	8.35	8.57	0.22	4% - 8%
5	8.07	8.35	0.28	8% - 16%
6	7.62	8.07	0.45	16% - 32%
7	7.1	7.62	0.52	32% - 48%
8	6.53	7.1	0.57	48% - 64%
9	5.9	6.53	0.63	64% - 80%
10	1.72	5.9	4.18	80% - 100%

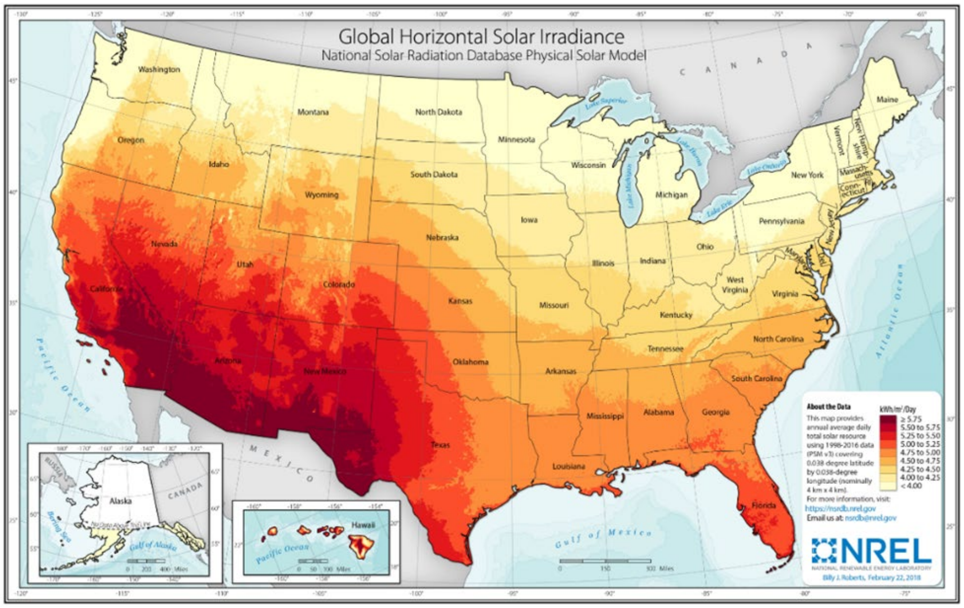
PART IV: UTILITY-SCALE SOLAR COSTS

Q37. Which NREL class was used to forecast solar cost assumptions, solar NCF assumptions and solar O&M and capital maintenance assumptions included in the IRP process/modeling?

A37. As described by Witness Cejas Goyanes in his testimony, the Company used Class 9 moderate for solar. NREL provides solar assumptions for 10 recourse categories in the United States, binned by mean global horizontal irradiance (GHI). As shown in Figure 2 below, most of Michigan is in the <4 GHS Bin.

[3] 2021 NREL Electricity Annual Technology Baseline (ATB) Land-Based Wind. Accessed January 20, 2022, from https://atb.nrel.gov/electricity/2021/land-based_wind

Figure 2: Average Annual GHI in the Unites States[4]



And as shown in Table 4 below, the corresponding resource class for the 3.75 - 4 GHI Bin is class 9.

Table 4: Utility-Scale PV Resource Classes[5]

Resource Class	GHI Bin	Mean AC Capacity Factor	Area (sq. km)
1	>5.75	32.80%	216,551
2	5.5 - 5.75	31.80%	349,894
3	5.25 - 5.5	30.30%	372,764
4	5 - 5.25	28.70%	497,444
5	4.75 - 5	26.80%	779,720
6	4.5 - 4.75	25.80%	870,218
7	4.25 - 4.5	24.60%	727,918
8	4 - 4.25	23.40%	828,438
9	3.75 - 4	22.30%	794,496
10	<3.75	20.40%	163,120

[4] 2021 NREL Electricity Annual Technology Baseline (ATB) Utility-Scale PV. Accessed January 20, 2022, from https://atb.nrel.gov/electricity/2021/utility-scale_pv

[5] 2021 NREL Electricity Annual Technology Baseline (ATB) Utility-Scale PV. Accessed January 20, 2022, from https://atb.nrel.gov/electricity/2021/utility-scale_pv

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PART V: UTILITY-SCALE RENEWABLE ENERGY RESOURCES INCLUDED IN THE PCA

Q38. Did the Company include a MW limit in the IRP modeling with regard to the amount of renewable energy that could be added in any given year after the starting point?

A38. Yes. In the pre-Inflation Reduction Act (IRA) model runs, the Company limited the number of incremental megawatts of renewable energy, after accounting for the renewable resources included in the starting point, that could be added in any one year to 500 MW of wind and solar combined in 2023-2025 and 1,000 MW of wind and solar combined in 2026 and beyond.

Q39. Why did the Company implement an annual MW limit for building future solar and wind projects?

A39. Experience has shown that delays in the MISO interconnection queue, recent RFP results, supply chain and labor market constraints, and local opposition can limit the amount of renewable energy that can be built at any given time. By placing a reasonable limit on the amount of MW of renewable energy that can be built on an annual basis, the Company can help ensure that modeling results are reflective of what is feasible to implement. There are several factors that the Company considered when determining appropriate limits on new solar and wind projects in the IRP modeling. These factors included: 1) the status of and challenges with the generation interconnection queue process; 2) siting, permitting and environmental considerations; 3) recent RFP experience; 4) supply chain issues; and 5) limitations in the IRP modeling tool that, absent the use of MW limits in the modeling

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assumptions, would select excess renewable energy.[6] An annual MW limit also allows the Company to take advantage of technological advancements and cost savings that may arise in the future. The Company is expecting to build on these advancements and efficiencies learned through the execution of the first several years of projects, thus, the annual MW limit increases over time. I discuss these factors below, with the exception of item five, which is addressed by Witness Manning in her testimony.

Q40. Can you discuss the experience with the MISO interconnection queue and how that relates to the MW build limit on renewable energy in the IRP modeling assumptions?

A40. The MISO generation interconnection (GI) process was targeted to take around 500 days under the tariff[7] but has experienced delays, with recent projects taking over 900 days to complete from start to finish.[8] The extended process with the additional risk of delays limits the ability of projects to become commercially operational by the date they are needed. MISO has recently made changes to its tariff reducing the targeted days to between 373 and 463 depending on one of two paths[9] available for the GI process. While some delay may be addressed through new MISO process and the new proposed interconnection rules at FERC,[10] the inefficiencies in the

[6] In this context, excess renewable energy refers to when the model builds more generation than is needed to meet the Company's load because it is economic to build the generation for wholesale into the MISO market and to utilize the tax credits to reduce the revenue requirement of the portfolio.
[7] Generator Interconnection Process Timeline Update, p 10. Accessed October 17, 2022, from https://cdn.misoenergy.org/20221010%20IPWG%20Item%2006%20BPM-015%20GIP%20Timeline%20Reduction626523.pdf
[8] Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021, p 22. Accessed October 17, 2022, from https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf
[9] Generator Interconnection Process Timeline Update, p 10. Accessed October 17, 2022, from https://cdn.misoenergy.org/20221010%20IPWG%20Item%2006%20BPM-015%20GIP%20Timeline%20Reduction626523.pdf
[10] See FERC Docket No. RM22-14.

interconnection process continue to be a concern. In addition, MISO saw an unprecedented number of applications[11] (956 totaling 170.8 GW) in its recent 2022 Generator Interconnection Queue (GIQ) application period, which as MISO's director of resource utilization, Andy Witmeier stated, calls for MISO needing to work with its stakeholders on the additional regional transmission needed to accommodate this resource shift.[12] MISO is projecting 2030 to be an inflection point in terms of new interconnections to support capacity expansion.[13] Given these trends, it is unclear if the timeliness and rates of completion of generation projects in the queue will improve to support increased levels of renewable energy deployments. For reference, the entire MISO footprint had 5,082 MW of capacity additions total (all resource types) in 2021.[14]

Solar and wind projects are both impacted by delays in the interconnection process. It should be emphasized, however, that there were no Michigan wind projects submitted to enter the MISO queue in 2022 despite an unprecedented number of generation interconnection applications. This means the current MISO queue includes nine potential wind projects in Michigan. These wind projects total to 1,162

[11] 2022 Generator Interconnection Queue Submissions. Accessed October 17, 2022, from https://cdn.misoenergy.org/2022%20GIQ%20Submission%20Statistics626443.pdf

[12] MISO's Generator Interconnection Queue cycle set new record. Accessed September 28, 2022, from https://www.misoenergy.org/about/media-center/misos-generator-interconnection-queue-cycle-set-new-record/

[13] 2022 Regional Resource Assessment, Presentation to the Resource Adequacy Subcommittee, August 24, 2022, p 14. Accessed October 17, 2022, from https://cdn.misoenergy.org/20220824%20RASC%20Item%2006%20Regional%20Resource%20Assessment%20Presentation626035.pdf

[14] Nearly 28 GW of new US generating capacity added in 2021, led by wind. Accessed October 17, 2022, from https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/nearly-28-gw-of-new-us-generating-capacity-added-in-2021-led-by-wind-68435915#:~:text=7%20Feb%2C%202022-,Nearly%2028%20GW%20of%20new%20US%20generating,in%202021%2C%20led%20by%20wind&text=The%20U.S.%20added%2027%2C959%20MW,S%26P%20Global%20Market%20Intelligence%20analysis

MWs. This coupled with the fact that in recent years ~75% of projects[15] in the MISO queue never achieved commercial operation, support the initial limit for wind in the pre-IRA model runs.

Q41. Can you discuss what siting, permitting and environmental factors were considered when determining the MW build limit on renewable energy in the IRP modeling assumptions?

A41. Yes. Siting has been a critical challenge for the development of new renewable energy projects, which is why time must be taken to build relationships and engage local leaders in order to mitigate local opposition to projects.[16] Local opposition has historically been an impediment to new renewable energy build. In Michigan, 45% of townships with wind ordinances have restrictions.[17] This was evident when the Company initiated a new wave of wind project prospecting in 2017. The Company started with ten possible areas, and this was quickly reduced to four projects due primarily to evidence of opposition. Despite tremendous focus on community engagement, the Company ceased development of three of those projects (mainly because the projects faced intense opposition). The remaining project has been built and will go on-line. But nearly four years after the project development started, there are still permitting details to be resolved. In addition, Michigan is primarily comprised of forested habitat, wetlands, waterways, developed land, and agricultural land. Siting wind projects in areas that are

[15] Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021, p 11. Accessed October 17, 2022, from https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf

[16] "Why Small Towns are Fighting Renewable Energy Development," Wall Street Journal, August 23, 2021. Accessed October 17, 2022, from https://www.wsj.com/video/series/wsj-explains/why-small-towns-are-fighting-renewable-energy-development/23CE8012-ACE5-418A-BBB9-93528EE69120

[17] Siting renewable energy in North America | Gerald R. Ford School of Public Policy. Accessed October 7, 2022, from https://fordschool.umich.edu/event/2021/siting-renewable-energy-north-america

predominately agricultural affords DTE the opportunity to conform to our long-standing environmental stewardship and limit potential impacts to sensitive species or their habitat. The IRP modeling takes into account that approximately 50% of Michigan is covered in forest, wetlands, and waterways, and considers the limitations on large areas of agricultural land available for development.

Q42. Can you describe how the Company's recent renewable resource RFP experiences have informed the MW build limit on renewable energy in the IRP modeling assumptions?

A42. In the 2019 Renewable Energy All-Source RFP that the Company conducted, 57 projects were submitted of which seven were wind and the rest solar. Similarly, in the 2022 Renewable Energy All-Source RFP the Company conducted, of the 22 projects submitted only one project submitted was wind. This supports the initial limit for wind in the model runs assuming the IRA tax credits as the current availability of wind projects in Michigan is very low and it will take time for projects to make progress.

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Q43. Can you provide more detail on the supply chain constraints, and international trade actions affecting the availability of solar panel modules being imported into the US?

A43. As Witness Leslie discusses in her testimony, the solar photovoltaic industry has recently faced disruptions on a global scale with supply chain constraints and international trade actions affecting the availability of solar panel modules being imported into the US. These developments have delayed some solar projects as reported by the US Energy Information Administration[18] and other sources[19] and created uncertainty for utilities and developers related to the pricing and availability of solar panels. Challenges associated with clean energy supply chains are discussed in a recent policy resolution, EL-1 Resolution on Improving Resilience, Sustainability and Security of Clean Energy Supply Chains, adopted by the National Association of Regulatory Utility Commissioners board in July 2022.[20] Importantly, the Inflation Reduction Act includes, among other provisions, incentives for domestic content in renewable energy projects and for the manufacturing of solar panels and their components in the United States. The Biden Administration has also taken actions, including executive orders and studies, to support increased domestic manufacturing of clean energy technologies, including solar.[21] These policies may shift market dynamics for solar and other technologies by increasing the diversity of manufacturers to meet growing demand. However, there is uncertainty in terms of the timing and extent of the impact of these policies

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[18] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Accessed September 2, 2022, from https://www.eia.gov/todayinenergy/detail.php?id=53400

[19] Clean Power Quarterly Market Report Q2 2022. Accessed September 2, 2022, from https://cleanpower.org/resources/clean-power-quarterly-market-report-q2-2022/

[20] 2022 NARUC Resolutions, pp. 1-2. Accessed October 17, 2022, from https://pubs.naruc.org/pub/5788B90C-1866-DAAC-99FB-8C01D2179A31

[21] See, e.g., New DOE Report, "Solar Photovoltaics Supply Chain Review Repot," Explores Strategy to Boost Domestic Solar Supply Chain. Accessed October 17, 2022, from https://www.energy.gov/eere/solar/solar-photovoltaics-supply-chain-review-report

on renewable energy project prices and equipment availability. Today, solar supply chain component manufacturing is heavily concentrated in China.[22] This recent experience with solar is an illustration of potential market risks that may affect the deployment of renewable energy.

Q44. Did the Company modify the MW limit in the IRP modeling with regard to the amount of renewable energy that could be added in any given year after accounting for the IRA tax credits in the modeling?

A44. Yes, in the modeling runs that include the IRA tax credits, the Company limited the number of incremental megawatts of renewable energy, after accounting for the renewable resources included in the starting point, that could be added in any one year to 400 MW of solar through 2028, then to 800 MW of solar in 2029-2034, while limiting wind to zero in 2023 through 2027, and 200 MW in 2028 through 2034. In addition, wind and solar combined were limited to 1,000 MW in 2035 and beyond.

Q45. Why did the annual MW limit for building future solar and wind projects change for the runs assuming the IRA tax credits?

A45. The annual MW limit for building future solar and wind projects changed in the IRP modeling runs where the IRA tax credits were applied for a few reasons. First,

[22] See US DOE, "Solar Photovoltaics Supply Chain Deep Dive Assessment: U.S. Department of Energy Response to Executive Order 14017, 'America's Supply Chains'" February 24, 2022. Accessed October 17, 2022, from https://www.energy.gov/sites/default/files/2022-02/Solar%20Energy%20Supply%20Chain%20Report%20-%20Final.pdf. The report found that "The solar supply chain is global and reliant on products from China or companies with close ties to China, a country with documented human rights violations and an unpredictable trade relationship with the United States." See also, International Energy Agency, Special Report on Solar PV Global Supply Chains, July 2022. Accessed October 17, 2022, from https://www.iea.org/reports/solar-pv-global-supply-chains; Center for Strategic and International Studies, Commentary: "The United States Needs a Solar Manufacturing Strategy," August 12, 2021. Accessed October 17, 2022, from https://www.csis.org/analysis/united-states-needs-solar-manufacturing-strategy

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as supported by Witness Cejas Goyanes in his testimony, the IRA extends PTCs at 100% eligibility for wind projects placed in service in 2022 and after, the economics for wind projects changed where the model would choose wind when it would not have before. In order to prevent the model from choosing more wind resources than would likely be feasibly built in the near term due to the factors discussed above, more stringent wind limits were put in place. Additionally, the execution of the 650 megawatts customer-requested special contract under the MIGreenPower program, which was filed in the September 2022 Amended REP, demonstrated there will likely be additional renewable needs to support the MIGreenPower program not included in the starting point but that should be taken into consideration in the earlier years in terms of the feasibility of deployment.

Q46. How did the Company determine the specific annual wind and solar MW limits?

A46. The limits were reasonable assumptions based on the factors discussed above. Given the challenges discussed in the testimony above, the Company assumed that the maximum amount of wind and solar MWs that could be built on an annual basis would be 1,000 MW in 2035 and beyond. However, in the near term between 2023-2025 in the pre-IRA runs or 2023 – 2034 in the IRA runs, we assumed this amount would decrease due to current supply chain and labor market constraints, current availability of viable wind projects, and demand for additional MIGreenPower assets not included in the starting point in that timeframe.

Q47. What amount of renewable resources is included in the Company's PCA over the first five years of the PCA from 2023-2027?

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A47. During the first five years of the PCA, the Company's PCA includes 800 MW of solar. These resources support the accelerated retirement of the first two units at Monroe Power Plant from 2039 to 2028. This includes some renewables that will be phased in prior to the first two units of the Monroe Power Plant being retired to ensure that reliability and resource adequacy are maintained. The PCA is outlined in detail by Witnesses Leslie and Mikulan in their testimonies.

Q48. What amount of renewable resources is included in the Company's PCA in the second five years of the PCA from 2028-2032?

A48. During the second five years of the PCA, the Company's PCA includes 3,600 MW of solar and 1,000 MW of wind.

Q49. What amount of renewable resources is included in the Company's PCA over the last 10-year period of 2033 through 2042?

A49. During the second 10-year period, the Company's PCA includes 2,100 MW of solar and 7,900 MW of wind. As Witness Leslie explains in her testimony, the first half of the 20-year proposal relies on known, readily available technologies, and we expect costs and commercially available technologies will change before implementing the second half of the plan.

Q50. How does the renewable build in the PCA relate to the Company's recently filed Amended REP application?

A50. The renewable energy included in the PCA is incremental to any VGP/MIGreenPower generation that has been previously approved or is pending approval. As stated earlier in my testimony, the renewable build plan assumptions in the IRP starting point are consistent with the most recently approved Amended REP in Case No. U-20851 filed in August 2020. Since that filing, in September 2022, DTE Electric has filed an ex parte Amended REP filing associated with a customer-requested special contract under the MIGreenPower program. The megawatts associated with the customer-requested special contract were not included in the IRP starting point or the PCA but were modeled as a sensitivity as I discuss above. Witness Manning addresses the results of the sensitivity analysis.

Q51. Does the IRP PCA change the forecasted incremental cost of compliance in the most recently filed Amended REP?

A51. No, these changes do not increase the incremental cost of compliance as the renewable resources included the IRP PCA are not assumed to be in the REP. Should the Company need to increase the amount of VGP resources to support the MIGreenPower program, the Company would need to provide an updated forecasted incremental cost of compliance in a future Amended REP.

Q52. Do these renewable resources included in the PCA impact the forecasted surcharge?

A52. No, these changes do not impact the forecasted surcharge.

Q53. Did the Company's PCA take into consideration the siting of such a large amount of incremental solar?

A53. No. Specific siting is not determined in the IRP, although limitations on the amount of renewables builds were taken into consideration in the IRP modeling process.

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Q54. What assumptions has the Company made about the location of future VGP developments?

A54. DTE Electric assumes all future VGP renewable energy will be developed within the state of Michigan, consistent with the program requirements. The VGP program is driven by customers with a desire to subscribe to local renewable energy as opposed to participating in programs based on out-of-state generation resources (e.g., carbon offsets).

Q55. What assumptions has the Company made about the location of future renewable energy that is not associated with the VGP program?

A55. The Company assumes future renewable energy that is not associated with the VGP program will be developed in Michigan for reliability purpose. Witness Burgdorf discuss reliability and resource adequacy considerations.

Part VI: FINANCIAL COMPENSATION MECHANISM

Q56. Is the Company authorized to apply a financial compensation mechanism (FCM) to PPAs?

A56. Yes, PA 341 explicitly authorizes the Commission to approve financial incentives for the utility when entering PPAs.

Q57. Does DTE Electric currently have an FCM?

A57. Yes. The Company is currently authorized to apply an FCM on future VGP PPAs equal to the Levelized Cost of Energy ("LCOE") difference between a self-build or Build Transfer Agreement ("BTA") project and the PPA, multiplied by a financial incentive factor of 30%, multiplied by MWh sold under the PPA. The FCM was approved by the Commission in its June 9, 2021, order in Case No. U-20713 and U-20851. This financial incentive would be added to the cost of the selected PPA and would be recovered through the subscription fee for the VGP program. To date, this FCM has not been implemented, though it is projected to be used for the PPA related to Savion Calhoun. Refer to Witness Lepczyk for additional details on the current FCM.

Q58. Is the Company requesting approval of an update to the Company's current FCM mechanism that would apply to PPAs as part of this IRP?

A58. Yes. In his testimony, Witness Lepczyk supports the reasonableness of a FCM mechanism for PPAs and proposes a new FCM mechanism apply to all new or modified PPAs.

<u>Part VII: REQUEST FOR PROPOSALS FOR RENEWABLE ENERGY AND STORAGE RESOURCES</u>

Q59. Did DTE Electric conduct an RFP for renewable energy prior to the IRP?

A59. Yes. Pursuant to MCL 460.6t(6), as interpreted by the Commission in its February 20, 2020 order at page 26, if the IRP includes new supply-side generation resources during the initial three-year planning period, the utility must issue a request for proposal (RFP) for such generation, use the results to inform the IRP, and include the RFP results in the IRP filing.

The Company provided solar and wind RFP overview documents, as shown in Exhibits A-9.1 and A-9.2, respectively, to all interested parties, and issued a renewable energy RFP for VGP assets on April 1, 2022; however, that RFP was paused due to the Department of Commerce (DOC) antidumping/circumvention investigation on solar panels imported from Southeast Asia. On June 30, 2022, the DOC released a Proposed Rule and Request for Comments implementing President Biden's June 6, 2022, Solar Presidential Proclamation, which led to the RFP being resumed on July 8, 2022. Proposals were received on July 29, 2022. For RFP results, see Exhibit A-9.3. This RFP information is included in this IRP filing to the extent MCL 460.6t(6) applies to this proceeding.

Q60. Did this RFP follow the Commission's new competitive bidding guidelines in Case No. U-20852?

A60. No. In MPSC Case No. U-20713, which is DTE Electric's 2020 VGP case which was consolidated with U-20851, the Company's latest approved REP case, the Commission approved a settlement that included specific RFP requirements for VGP assets through 2025. The VGP settlement RFP structure incorporates many features that the Commission included in its new competitive bidding guidelines.

A subset of the settlement is further described. The agreed RFP format includes an open, non-discriminatory treatment of resources without a minimum project size threshold. *Id*. at §11.2. The RFPs will be transparent, with disclosure of RFP requirements and specification of evaluation criteria. *Id*. at §11.3. The RFP structure includes separation of DTE employees and affiliates who have responsibility for bidding projects from the group that will be involved in designing the RFP, conducting the RFP and evaluating the bids. *Id*. at §11.4.1. DTE Electric will use an independent third-party evaluator to oversee the competitive solicitation process if utility self-build or affiliate project bids or proposals will be considered for the utility's competitive solicitation. *Id*. at §11.4.4. Consistent with the oversight principles set out in *Allegheny Energy Supply Co, LLC*, 108 FERC 61082 (2004), the independent evaluator will (1) work with DTE Electric to design the solicitation, (2) oversee administration of the bidding, and (3) evaluate bids for minimum qualifications as described in the RFP documents, prior to DTE Electric's selection. *Id*. at §11.4.6.1. While the settlement provisions are closely aligned with the competitive bidding guidelines in Case No. U-20852 and will ensure that the Company's VGP projects are competitively priced and as diverse as possible, there are minor differences between the two.

Q61. How will future RFPs for VGP projects after 2025 or for non-VGP projects follow the Commission's new competitive bidding guidelines in Case No. U-20852?

A61. For future RFPs that contemplate either VGP projects after 2025 or that are for non-VGP projects, the Company will assess its experience with competitive bidding under the VGP settlement RFP structure and assess whether there are improvements to the process that it can incorporate from the Guidelines. RFPs would cover energy storage and renewable energy resources.

Q62. Does this complete your direct testimony?

A62. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MARKUS B. LEUKER

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 testifying on behalf of DTE Electric Company (DTE Electric or the Company).

Q2. What is your present position with the Company?

A2. I am the Manager of Corporate Energy Forecasting.

Q3. What is your educational background?

A3. I received a Bachelor of Science 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 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 work 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 to my experience with DTE Electric and IHS, I worked as North American Manager, Market Research & Analysis for Visteon Corporation where I managed global coordination of the research function

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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 activities and regulated marketing activities.

Q5. What are your duties as Manager, Corporate Energy Forecasting?

A5. I am responsible for the development of the economic and electric sales forecasting activities for DTE Electric. These activities include data collection, statistical analysis of data, forecast model building and interaction with other departments on forecast-related activities. My role also includes the preparation of long-term (one year or greater) sales forecasts, short-term (monthly) forecasts, next day forecasts, and the economic forecast that supports the sales forecast.

Q6. Do you 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 forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan. I serve as a member of Itron's Electric Forecasting Group.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission?

A7. Yes. I sponsored testimony in the following cases:

Line No.		
1	U-17097	2013 PSCR Plan
2	U-17302	2013 Renewable Energy Plan Update
3	U-17319	2014 PSCR Plan
4	U-17680	2015 PSCR Plan
5	U-17762	2016-17 Energy Optimization Plan
6	U-17767	DTE Electric General Rate Case
7	U-17793	2015 Renewable Energy Plan
8	U-17920	2016 PSCR Plan
9	U-18014	DTE Electric General Rate Case
10	U-18111	2016 Amended Renewable Energy Plan
11	U-18143	2017 PSCR Plan
12	U-18255	DTE Electric General Rate Case
13	U-18262	2018-19 Energy Optimization Plan
14	U-18419	2017 Certificate of Necessity
15	U-18403	2018 PSCR Plan
16	U-18232	2018 Renewable Energy Plan
17	U-20162	DTE Electric General Rate Case
18	U-20221	2019 PSCR Plan
19	U-20471	2019 Integrated Resource Plan
20	U-20561	DTE Electric General Rate Case
21	U-18232	2020 Amended Renewable Plan
22	U-20836	DTE Electric General Rate Case

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to provide the Company's electric sales, maximum demand and system output forecast for the period 2023-2042. I will discuss the business climate and the outlook for the local economy, which is the basis of the forecast. I will describe how the forecast of electric sales, maximum demand and system output is developed. Additionally, I will explain how energy waste reduction (EWR), distributed generation (DG), building electrification and electric vehicles (EV) are incorporated into the forecast. I will also give an update on recent load forecasting related recommendations and orders proposed by the Commission. My testimony will support the reasonableness of the electric sales forecasts used by DTE Electric in its Integrated Resource Plan (IRP) process.

Q9. Are you supporting any exhibits?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-10	Annual Sales by Major Customer Classes 2017-2021 Historical
A-10.1	Annual Sales by Major Customer Classes 2017-2021 Historical Weather Normalized
A-10.2	Annual System Output, Maximum Demand and Load Factor 2017-2021 Historical
A-10.3	Starting Point Annual Sales by Major Customer Class 2022-2042 Forecast
A-10.4	Annual Service Area Sales, System Output and Demand for Sensitivity Load Forecasts 2022-2042 Forecast

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A-10.5 Monthly MAPEs of Service Area Electric Sales and Peak 2017-2021 Historical

A-10.6 Annual Customer Counts by Major Customer Classes 2017-2021 Historical 2022-2042 Forecast

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Q11. Did you provide inputs to the group responsible for producing DTE Electric's IRP?

A11. Yes. As described by Company Witness Manning and further explained later in my testimony, I provided 10 forecasts for use in the IRP process:

1. Starting Point
2. High Load Growth
3. Return of 50% of Retail Choice Load
4. Aggressive Customer Owned Distributed Generation
5. High Electrification
6. Stakeholder
7. Stakeholder with 25% Distributed Generation Growth Until 2030
8. Stakeholder with High Fuel Switching
9. Electric Choice Cap Increases to 15%
10. Climate Change

Q12. How is your testimony organized?

A12. My testimony consists of the following five parts:

Part I Business Climate and Outlook
Part II Forecast Development and Assumptions
Part III Recent Recommendations and Orders Related to Load Forecasting
Part IV Historical and Forecast Electric Sales, Demand and System Output
Part V Electric Load Forecast Sensitivities

<u>Part I: Business Climate and Outlook</u>

Q13. What effect has the Coronavirus (COVID-19) outbreak had on the economy?

A13. COVID-19 disrupted virtually all sectors of the economy, and many institutions failed to anticipate its severity. In early March of 2020, only days before many businesses moved their workers from office to home, IHS Markit forecasted 2020's real gross domestic product (GDP) to grow by 1.8%. In fact, real GDP declined by 3.4%. Real personal consumption expenditures, which account for roughly 70% of GDP, declined by 3.8%, and unit volume automotive production by 18.6%. Boosted by stimulus payments, real disposable personal income rose by 6.2%. Reflecting broad-based economic weakness, the Consumer Price Index for All Urban Consumers (CPI-U) rose by only 1.2%.

After declining sharply in the second quarter of 2020, the economy did an about-face and began a similarly abrupt recovery. In 2022, GDP is on track to grow by 4.3%, personal consumption expenditures by 3.4%, and auto production by 15.9%, while disposable personal income is expected to decline by 3.3%. Pressured by supply bottlenecks, perhaps the most publicized of which is a lingering shortage of semiconductors, the CPI-U is expected to increase by 3.0%.

Q14. What is the business climate in DTE Electric's service area?

A14. 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 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 strong near-term increase in automotive production, though component shortages arising from COVID-19 and other economic constraints limit growth from achieving its potential.

Q15. What is the outlook for Southeast Michigan's economy over the time horizon of the study period, 2023-2042?

A15. Forecast uncertainty can increase in outer years, making it advantageous to discuss separately the economic prospects for 2023, the medium-term and the long-term. Medium-term changes are represented by the compound annual growth rate (CAGR) from base year 2023 through 2027, and long-term changes by the CAGR from 2027 through 2042. In 2023, total nonfarm employment increases by 1.5%, natural resources and mining employment declines by 1.9%, manufacturing employment increases by 0.8%, total private non-manufacturing employment by 1.6%, government employment by 1.3%, and automotive production by 25.4%, while population holds steady.

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Over the medium-term, total nonfarm employment rises by 0.2%, natural resources and mining employment declines by 0.8%, manufacturing employment declines by 1.6%, total private non-manufacturing employment rises by 0.5%, government employment rises by 0.2%, automotive production declines by 0.1%, and population rises by 0.1%.

In the long-term, total nonfarm employment declines by 0.1%, natural resources and mining employment rises by 0.6%, manufacturing employment declines by 0.4%, total private non-manufacturing employment remains unchanged, government employment declines by 0.2%, automotive production rises by 0.1%, and population declines by 0.1%.

Part II: Forecast Development and Assumptions

Q16. What is the general approach used in developing the forecast of DTE Electric's service area electric sales and system output?

A16. The general approach reflects widely accepted industry standards for electricity forecasting, including regression and end-use modeling. This approach has, over time, also provided reasonable forecasts for DTE Electric service area electric sales with, on average, small variances from actual historical annual sales.

Most customer class sales and customer forecasts are built from linear regression models that relate monthly sales to economic activity, weather, changes in end-use saturation, and energy efficiency. The forecast is developed separately for each major rate classification: Residential, Commercial and Industrial (C&I), and other. The residential sales forecast is derived by combining a use-per-customer forecast, using a statistically adjusted end-use (SAE) specification, with a customer forecast. Separate models are estimated for small and large C&I customers. Small C&I, comprised of over 200,000 small business customers, is modeled similarly to residential, while large C&I, comprised of over 3,000 high consumption large business customers, is forecast using generalized econometric models unique to seven supersectors. Other, which consists of Streetlighting and Traffic Signals, is forecast based on growth in customers, and adoption of more energy efficient lighting. The net system output is forecasted as the sum of the electric sales values and the projected losses.

There are many factors that impact the sales and customer forecasts for each customer class. Examples of forecast drivers include:

- National, state, and local economic projections provided by sources including, but not limited to: IHS Markit, Moody's Analytics, and Auto Forecast Solutions
- The Energy Information Administrations (EIA) Annual Energy Outlook (AEO) 2021 end-use intensity and end-use saturation estimates for the East North Central Census Division (modified for DTE Electric's end-use information)
- Mobility Data sourced from Google to model the effects of the COVID-19 pandemic
- Historical weather data from the Detroit Metropolitan Airport, with normal weather assumptions in the forecast horizon
- DTE Electric's EWR targets based on the 2021 Michigan Energy Waste Reduction Statewide Potential Study

- Behind-the-meter DG projections for DTE Electric's service territory provided by ICF Resources LLC
- DTE Electric's EV forecast for light-duty and fleet vehicles
- Large customer load adjustments that would not be reflected in the historical data or economic projections

Q17. Can you please describe the data used to construct the forecast models?

A17. Each model to forecast sales was estimated with monthly historical consumption data beginning in January 2006, with estimation ending in October 2021. Customer count forecast models were estimated with monthly historical customer count data beginning in January 2010, with estimation ending in October 2021.

The forecast for both sales and customers was extended through 2042 and was used to develop the long-term system energy and peak demand forecast.

The Hourly Electric Load Model (HELM), described later in my testimony, utilized hourly historical customer class level data as the basis for developing a suite of load profiles that were used to forecast the peak demand.

Q18. Why was October 2021 the last historical observation used in the forecast models?

A18. The forecast began construction in November 2021, with the final version completed in January 2022. Integrated Resource Plans can typically take 12 months or longer to develop, with the load forecast being one of the first inputs needed to begin modeling and analyzing potential proposed courses of action (PCA).

Therefore, it was necessary for the Company to provide a long-term sales forecast to the IRP team with adequate time to be used in the IRP process and develop a PCA.

Q19. How is weather applied in the load 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 understand the unique relationship that a customer class's energy consumption has with weather. HDDs are calculated by subtracting average daily temperature from a defined base such as 65 degrees Fahrenheit. Conversely, CDDs are calculated by subtracting the aforementioned base, from average daily temperature.

In regression modeling, a coefficient is measured to quantify this impact. Once the coefficient is calculated, it is applied to the weather assumed in the forecast horizon. In the forecast horizon, normal weather is assumed as the most prudent form of weather expectations for the future.

Q20. Can you please describe the HDD and CDD bases used in the forecast?

A20. As seen in Figures 1 and 2, weather response is different depending on the customer class. Residential sales are more responsive to weather and typically begin cooling building stock at an average temperature of 60 degrees. Small C&I sales are less responsive to weather and typically begin cooling building stock at an average of 50 degrees. The relationships to weather are also non-linear, creating a need to utilize multiple HDD and CDD bases to accurately capture the weather response.

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HDD and CDD bases, represented by the name and temperature of the base, for each customer class include:

- 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

Figure 1: Residential Daily Use-Per-Customer vs Temperature

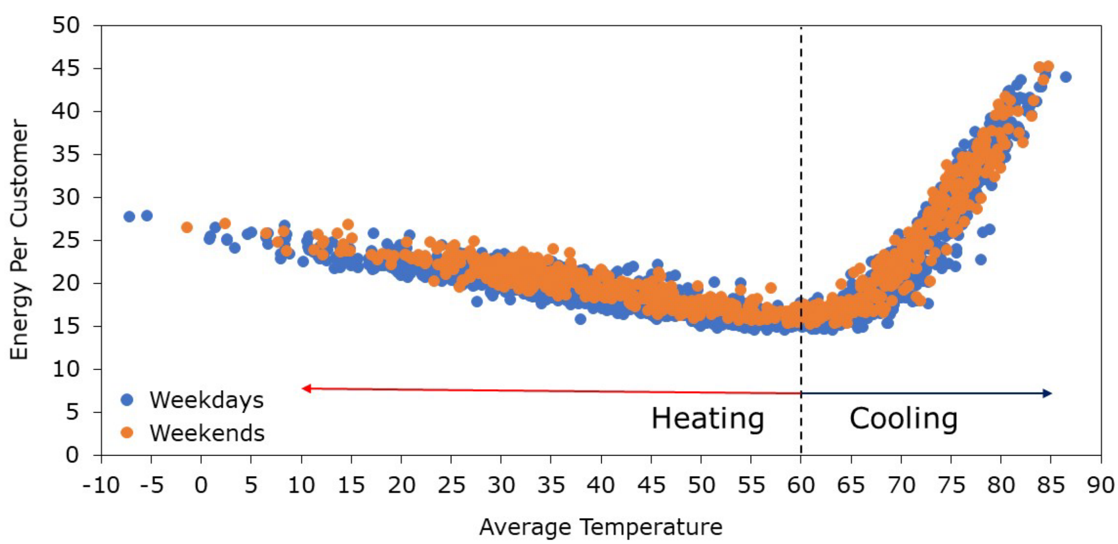

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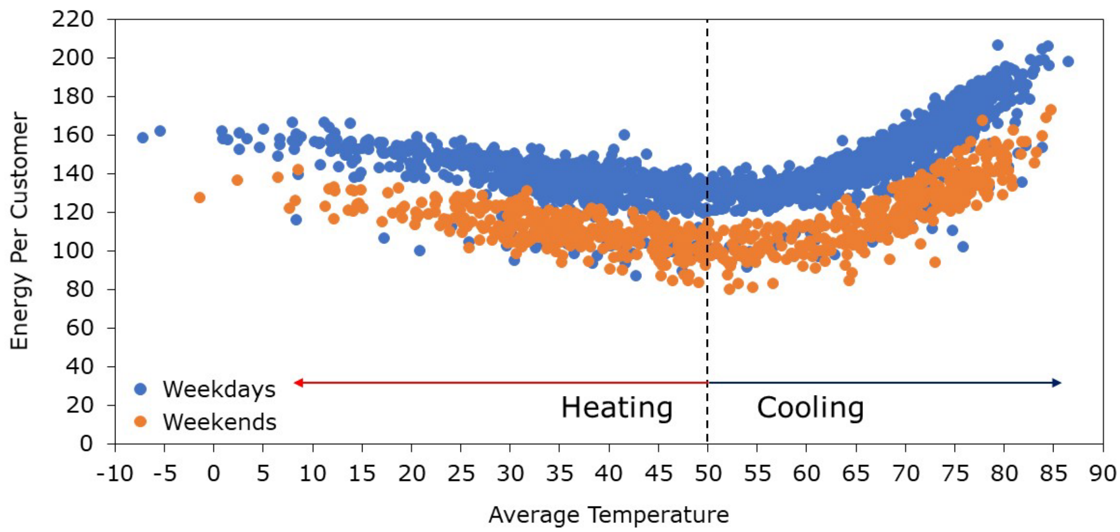
Figure 2: Small C&I Daily Use-Per-Customer vs Temperature



Q21. How does DTE Electric define normal weather?

A21. Normal weather is defined as a 15-year average of historical values, updated on an annual cadence. 2006-2020 is the timeframe for normal weather in this instant case. Daily average temperature is converted to HDDs and CDDs for various bases and averaged across years. As a result, this process calculates and defines normal HDDs and CDDs for various bases in a given day, month and year.

Q22. How was the residential class forecast developed?

A22. Electricity sales in the residential class were forecast using the statistically adjusted end-use (SAE) model which specifies energy use as a function of 22 end-uses, including DG and EV demand, along with factors that affect the end-use requirements such as economic activity and weather. The residential class forecast began with a basic end-use model with appliance saturation projections and average electricity usage per end-use provided by a Company-conducted residential appliance saturation survey and the EIA's AEO 2021 for the East North Central region in which DTE Electric operates. Historical and forecast residential EWR savings are applied directly to the corresponding end-uses as a subtraction in the SAE model. The combination of appliance saturations and average electricity per end-use is indexed and calibrated to the Company's usage per customer for the base year to create an electricity forecast for each end use.

End-use intensities are combined with utilization variables which reflect how much the end-use is utilized. For residential, the primary variables used to explain utilization are weather, real personal income, population, and households. Additionally, resulting from the COVID-19 pandemic, Michigan mobility data was integrated into the model due to the shift in electricity consumption patterns caused by social distancing policies and work from home practices. The utilization variables are then combined with the end-use intensities to compute three explanatory variables that are:

- 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

Along with seasonal factors, the resulting explanatory variables are then regressed against the Company's residential 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 number of residential customers was forecasted using historical and projected households for southeast Michigan provided by IHS Markit. Customer counts are modeled using a regression, with households as the primary explanatory variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total residential class sales forecast.

Q23. How was the small C&I Forecast developed?

A23. Similar to the residential class forecast, small C&I class sales are also forecast Using an SAE model, utilizing 11 end-uses including DG and EV demand. Additionally, C&I EWR programs are incorporated directly into the SAE model. The small C&I sales forecast began with a basic end- use model with saturation projections and average electricity usage per end-use derived from the EIA's AEO 2021 for the East North Central region in which DTE Electric operates. Since small C&I buildings within the DTE Electric service territory consume electricity differently, the projections are weighted by intensity and prevalence of 11 different building types as defined by the EIA. To better calibrate these projections to the Company's service area, employment values are used to weigh end-use intensities with the Company's service area employment data. The combination of saturations and average electricity per end-use is indexed and calibrated to the Company's

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usage per customer for the base year to create an electricity forecast for each end-use.

For small C&I, the primary variables used to explain utilization are weather, gross state product, non-manufacturing employment and households. The utilization variables are then combined with the end-use intensities to compute three explanatory variables that are:

- 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

Along with seasonal factors, the resulting explanatory variable is then regressed against the Company's small C&I 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.

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Small C&I customers are modeled using a regression with residential customers 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.

Q24. How was the large C&I Forecast developed?

A24. The large C&I forecast began by disaggregating all primary service sales into seven distinct supersector markets. Granular market segments defined by the customer's North American Industry Classification System (NAICS) code are aggregated into supersectors defined by the Bureau of Labor Statistics. The seven supersectors include medical and education, TTU, offices, other markets, automotive, other manufacturing, and steel.

Econometric models, a commonly used technique among utility forecasters, are used to forecast sales for the Company's service territory at the supersector level. Individual regression equations are applied to all supersectors, using various 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 reasonableness and validated through various model statistics.

Regression modeling alone does not account for incremental growth of technologies such as DG and EV. Unlike residential and small C&I, large C&I is not modeled by end-use. Therefore, it is necessary to make post-regression adjustments to the forecast to incorporate future technology and customer specific closings or expansions. The three main post regression adjustments include DG growth, fleet electrification growth, and large customer projects that are informed by customer account managers.

Q25. Does the load forecast consider the effects of the recently passed Inflation Reduction Act (IRA)?

A25. No, as described above, the forecast and accompanying load scenarios were developed in January 2022. As explained by Witness Leslie, the IRA was enacted into law in August 2022, and includes incentives for energy efficiency, renewable energy, electric vehicles and building electrification. Given the recency of the IRA, the uncertainty of the exact impacts, and the timing associated with completing an IRP, there was inadequate time to understand and include these impacts into the load forecast.

Q26. What impacts could the Inflation Reduction Act have on the load forecast?

A26. As described by Witness Bilyeu, it is too early to project with certainty what impacts the IRA will have on things like energy efficiency, as well as adoption of DG, EVs, and electrified appliances. Although it is possible the IRA may help customers reduce energy through expanded energy-efficiency or become more energy independent through increased DG adoption, guidance still needs to be determined[1]. Conversely, electricity demand may increase as a result of increased

[1] https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf, accessed October 20, 2022 i. e., Section 50121: Whole-home Energy Efficiency Retrofit Rebates - TBD whether utilities could be secondary-grantees or pass-through rebates to customers; 50141: GHG Reduction Projects - Eligible recipients TBD; Section 13491: New electric vehicle tax credit – TBD which dealers will participate in instant rebate programs and structure of Treasury program; Section 50131: Advanced Building Codes – TBD how states and local governments will modify building codes; Section 50122: Residential Building Electrification – TBD grant amount for each state and how it will be allocated

consumer adoption of EVs and building electrification from available grant dollars and tax credits.

The IRA includes long-term opportunities and understanding its effects on EWR, as well as EV, DG, and building electrification adoption will likely be captured in subsequent regulatory filings and IRPs.

Q27. Are the potential impacts of the IRA captured in any of the alternative load forecasts used as an input to the IRP?

A27. Possibly. While not explicitly accounting for the impacts of the IRA, the IRP includes nine other alternative load forecasts, as well as many sensitivities around EWR that may secondarily capture impacts from the IRA. For example, and described in detail later in my testimony, the load forecasts alternatives ran include aggressive adoption rates for EVs, two alternative forecasts around accelerated DG adoption, as well as two alternative forecasts around increased adoption of fuel switching from fossil fuel end-uses to electric. While these alternatives are not intended to represent the exact impacts the IRA may have, they likely provide a range of possibilities in which the IRA impacts could fall.

Q28. How was the Electric Choice sales forecast developed?

A28. The Electric Choice sales forecast was based on 10% of retail sales. Historical class ratios are applied to the Choice cap and new customer load is added separately. Additionally, the Company has developed sensitivities for varying levels of Electric Choice sales which are further explained in Part IV of my testimony.

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Q29. Does the forecast consider EVs, DG, EWR, and Building Electrification?

A29. Yes. Individual outlooks for EV, DG, EWR, and building electrification were developed and applied to the residential, small C&I and large C&I class forecast models.

Q30. How was the EV outlook applied to the forecast?

A30. For the EV forecast, the Company utilized historical trends and other industry experts[2] to forecast the EV stock in DTE Electric's service area. The EV stock was then used to estimate the historical and forecasted load in the Company's service territory.

The EV stock is multiplied by a KWh/vehicle value and the assumed vehicle miles traveled unique to each vehicle segment to arrive at the load associated with the forecasted vehicle volumes.

For light-duty vehicles, the Company's appliance saturation survey suggests approximately 75% of EV charging is done at personal residences while the other 25% is done at non-residential locations, such as workplace or public charging stations. Therefore, approximately 75% of the light-duty EV sales forecast was applied to the residential model as an additional end-use while the remaining was applied to the small C&I model as an additional end-use as a starting point. Over time, as EV adoption becomes more mainstream, the forecast assumes these dynamics will shift in favor of increased non-residential charging. As public infrastructure is built out to support direct current (DC) fast charging and

[2] BNEF (national), Automotive Communities Partnership (national), and IHS Markit (Michigan) forecasts were used for the updated forecast

consumers without access to home charging begin to adopt EV's, the boundary between home and public charging is projected to overlap. For fleet (medium-duty and heavy-duty) vehicles, 100% of the fleet EV sales forecast was applied to the large C&I model as an incremental adjustment to the forecast.

Q31. What is the outlook for EVs?

A31. EVs are projected to be the fastest growing end-use amongst customers in DTE Electric's service territory. Recent announcements by major automakers indicating their goals to phase out sales of internal combustion engine vehicles, combined with increasing consumer interest, show the future of mobility is electric. In Michigan, 2021 EV sales more than tripled those from 2020.

Light-duty EV stock is projected to grow 19.3% annually on average from 2023 through 2042 in DTE Electric's service territory. In 2021, roughly 2.7% of new light-duty vehicle sales are electric, this is projected to grow to 22% by 2030 and 53% by 2040. Recently, policy makers and stakeholders alike have expressed a desire to target 50% of new vehicle sales to be electric by 2030. Given this information, various sensitives were performed to understand the impacts to resource planning as described later in my testimony. Please refer to Table 1 for more detail on the Starting Point outlook for EVs.

Table 1: Light-Duty Electric Vehicle Outlook

	2021	2025	2030	2035	2040
Vehicle Stock (cumulative vehicles)	**22,147**	**103,300**	**375,312**	**825,662**	**1,287,616**
% of New Sales	**3%**	**9%**	**22%**	**36%**	**53%**
% Penetration	**1%**	**3%**	**11%**	**24%**	**38%**
Projected Load (GWh)	**64**	**347**	**1,303**	**3,028**	**4,977**

Electric fleet stock is projected to grow 20.2% annually on average from 2023 through 2042 in DTE Electric's service territory. Please refer to Table 2a for more detail on the Starting Point outlook for electric fleet.

Table 2a: Electric Fleet Outlook

	2021	2025	2030	2035	2040
Vehicle Stock (cumulative vehicles)	**57**	**391**	**1,298**	**3,178**	**5,523**
Projected Load (GWh)	**1**	**14**	**74**	**195**	**312**

Q32. What type of DG resources were included in the forecast?

A32. 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 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).

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Q33. How was the DG outlook applied to the forecast?

A33. The DG outlook was developed utilizing the Company's residential and non-residential interconnection history. The Company engaged with ICF Resources LLC (ICF), a global consulting service company, to conduct a market study. ICF produced forecasts of PV economics for both residential and C&I customers and estimated the customer PV capacity and electricity output that will be added in DTE Electric's service territory.

In the residential and small C&I models, the historical and forecast DG is input directly as an end-use into the model. In the large C&I models, the incremental DG is subtracted as a post-regression adjustment.

Q34. What is the outlook for DG?

A34. Interest in customer-owned DG has grown steadily in recent years with the inception of DTE Electric's legacy net-metering and current DG program. On average from 2007 to 2018, DTE has interconnected just over 2,000 kW of new Solar PV annually to the distribution grid. From 2019 to 2021 this number jumped to roughly 10,000 kW, on average, of new solar PV added annually. The load forecast assumes these patterns continue moving forward as costs for these technologies come down. DG is expected to grow 9.2% annually, on average, from 2023 through 2042. Recognizing that costs for these technologies may decline faster than projected, the Company ran several alternative forecasts with higher growth in DG for resource planning that is described later in my testimony. Please refer to Table 2b for more detail on the Starting Point outlook for DG.

Table 2b: Distributed Generation Outlook (Cumulative capacity in MW)

	2021	2025	2030	2035	2040
Residential Installed Capacity	35	64	119	195	266
C&I Installed Capacity	25	41	73	112	147
Total Service Area Installed Capacity	60	106	192	307	413

Q35. How was the EWR outlook applied to the forecast?

A35. The EWR forecast was developed by Company Witness Bilyeu. The Starting Point forecast assumes EWR savings levels consistent with the 2021 Energy Waste Reduction Statewide Potential Study and was modeled for each of the three customer class forecasts. Since historical and forecast EWR savings are available at the end-use level for residential, those savings were applied directly to the corresponding end-uses in the residential SAE model resulting in lower end-use intensity projections. C&I EWR savings were applied to both the small C&I and large C&I forecast models as an explanatory variable in their respective regression models.

Incremental increases in EWR are evaluated through the IRP modeling process further explained by Company Witness Manning.

Q36. How was building electrification applied to the forecast?

A36. For most other end-uses, the residential model utilizes saturation projections from the EIA's AEO 2021 for the East North Central region. Given the growth in heat pumps experienced over the last ten years in DTE Electric's service territory, EIA's heat pump projection was not used due to both EIA reporting relatively flat growth

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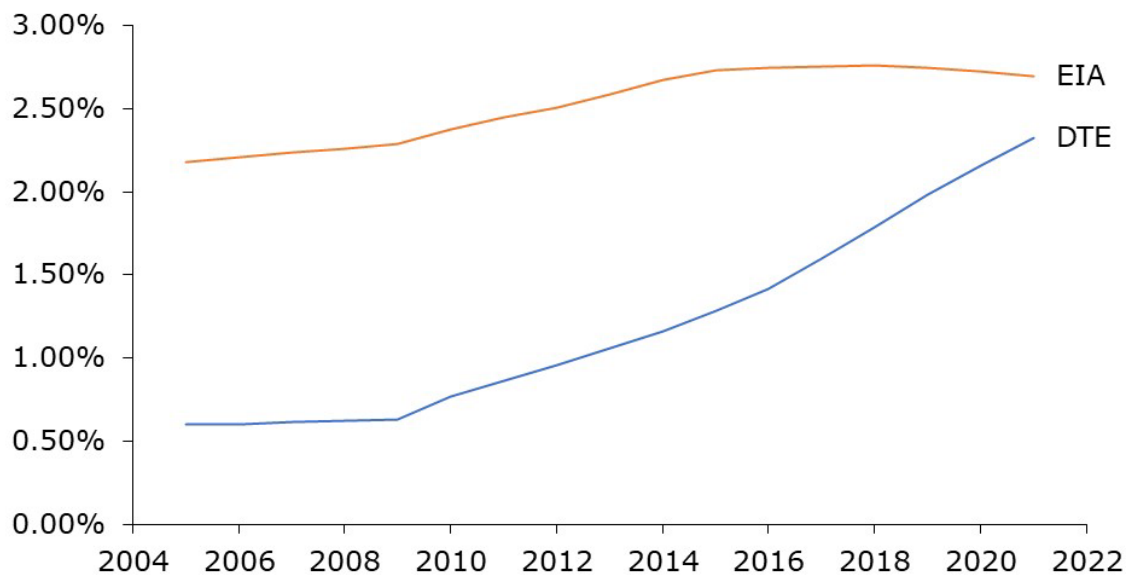
in heat pumps from 2009-2021, as well as projected declining heat pump saturation for the East North Central Region. Figure 3 displays these historical differences. The residential forecast assumes modest growth in heat pump adoption will persist as customers with baseboard, propane, or fuel oil heating systems turn over and adopt a more efficient and cost-effective technology to heat their home. Historical and forecast heat pump adoption is modeled as an additional end-use in the residential forecast.

Figure 3: DTE vs EIA Historical Air-Source Heat Pump Saturation



Q37. What is the outlook for building electrification?

A37. While still in the early phases of adoption, air-source (ASHP) and ground-source (GSHP) heat pumps have recently become a more viable solution for some residential customers to help reduce their carbon footprint and lower their heating costs compared to baseboard, propane, or fuel oil heating systems. Beginning in 2009, heat pump adoption began to gain modest traction in DTE Electric's service

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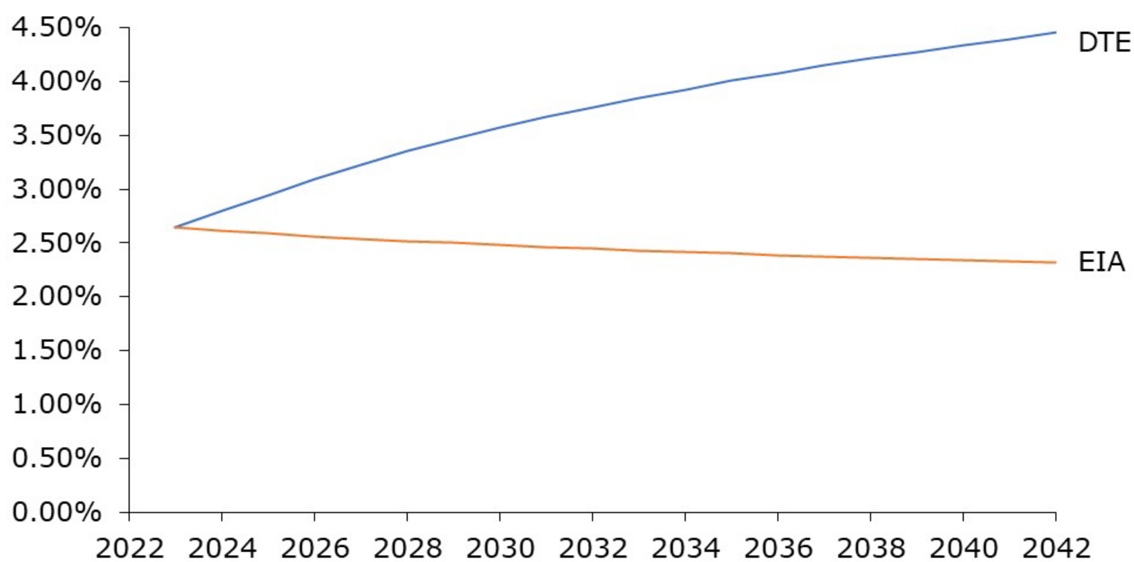
area. The forecast assumes growth in heat pumps will increase by 2.8% annually, on average, from 2023 through 2042. Conversely, EIA expects heat pump growth in the East North Central Region, in which DTE Electric resides, to decline by -0.7% annually on average from 2023 through 2042. Please refer to Figure 4 for a visual comparison of DTE Electric's and EIA's heat pump saturation projections.

Figure 4: Residential Heat Pump Saturation Comparison



Q38. How was the DTE Electric system peak demand forecast developed?

A38. The HELM was used to forecast annual DTE Electric service area and DTE Electric bundled peak demand. HELM was also utilized to determine monthly peak demands in the forecast period.

Q39. What is HELM?

A39. HELM is a bottom-up approach to developing the peak forecast by summing hourly load profiles. Load profiles are developed for each of the sales classes utilizing the company's historical hourly Advanced Metering Infrastructure (AMI) data. Residential and small C&I classes were further broken into base, cooling, and heating end-uses which enables the ability to capture changing peak demand levels based on the composition of the underlying load shapes, and changes in end-use consumption. Additional load profiles for new technologies such as EVs and DG are also used.

The profiles are scaled to the annual energy forecasts by customer class, adjusted for losses, and summed to predict the system total. The highest hourly value in a year or month is the peak forecast. Modeling system peak using a bottom-up approach is advantageous in that it enables the ability to model sensitivities around load shape diversity. As customers adopt more efficient HVAC units, or technologies such as EVs increase in penetration, a bottom-up approach provides the ability to understand changes in the system peak, as well as the hour in which it occurs.

Q40. What temperature assumptions were made regarding the DTE Electric service area and DTE Electric bundled peak demand forecast?

A40. Normal temperature on the day of the annual peak is assumed to be 82.8 F, which is the mean temperature from Detroit Metropolitan Airport. This value is based upon an average peak-day mean temperature for a 15-year period (2006 through 2020). The mean temperature is calculated as the average of hourly temperatures for the day. The peak day is assumed to occur on a weekday in July.

Q41. Are Demand Response (DR) programs included in the Company's peak forecast?

A41. DR programs are not explicitly included in the peak 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 Company Witness Burgdorf.

Part III: Recent Recommendations and Orders Related to Load Forecasting

Section I: Recommendations from Case No. U-20471

Q42. What orders were adopted related to load forecasting in the Company's last integrated resource plan?

A42. On page 49 of the Commission's order in Case No. U-20471 it outlines recommendations that were adopted for improving DTE Electric's load forecast. Specifically, the Commission ordered the following:

- Determine and report the mean absolute percentage error (MAPE) on monthly energy sales and peak load
- Use a shorter historical period for weather-normalization
- Provide an update on the implementation of using increasingly more granular data in the forecast models

I will discuss progress on each of these recommendations in greater detail.

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Q43. Pertaining to the first recommendation in Case No. U-20471, has the Company been able to determine and track MAPEs on monthly energy sales and peak demand?

A43. Yes. As seen in Exhibit A-10.5, I have provided DTE Electric's most recent monthly forecast MAPEs on both service area sales and service area peak demand. MAPE is a measurement of model error in which smaller values suggest better performance. The five-year average of monthly MAPE's on service area sales is 2.1% which is better than the industry benchmark of 3% or higher in some cases. The five-year average of monthly MAPE's on service area peak demand is 4.3%, with the last year 2021, showing an improvement over previous years MAPE at 1.6%.

Q44. Why was 2021's monthly MAPE for peak demand better than in previous years?

A44. The HELM model used to forecast peak demand formerly relied on sample load profiles from various sources. In 2020, the Company updated its HELM model to be sourced from actual hourly AMI data by customer class from the Company's service territory. The year 2021 was the first year the Company was able to utilize its own hourly data to forecast peak demand.

Q45. Pertaining to the second recommendation in Case No. U-20471, has the Company moved to a shorter time period for weather-normalization and the assumed normal weather in the load forecast?

A45. Yes. As explained earlier in my testimony, the Company now utilizes both a shorter and more recent time period to define normal weather. The weather assumed in the

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load forecast for this instant case is a 15-year average of historical values from 2006-2020. In Case No. U-20471, the Company utilized a 30-year normal weather period from 1981-2010. The differences between the 30-year normal weather period used in Case No. U-20471 and the 15-year normal weather used in this instant case can be seen in Table 3.

Table 3: Normal Weather Comparison

Case No.	Historical Time Period	Annual HDD65s	Annual CDD65s	Winter Peak Day HDD65s	Summer Peak Day CDD65s
U-20471	1981-2010	6,174	803	58	18
U-21193	2006-2020	5,969	899	57	18

Q46. Pertaining to the third recommendation in U-20471, has the Company made progress to utilize more granular data in its forecast models?

A46. Yes. Since the last IRP, DTE Electric has integrated AMI data into many of its processes. Recently, the Company began using aggregated AMI data in its long-term customer class forecast models, in lieu of monthly billing data where available. Daily AMI data is aggregated by customer class or supersector and appended to a longer history of billing data to use as the basis for its long-term sales forecast models. For the residential and small C&I models, AMI data is used for years 2015-2021 with billing data utilized prior to 2015. For large C&I, AMI data is used for years 2018-2021 with billing data utilized prior to 2018.

The HELM model used to forecast peak demand formerly relied on sample load profiles from various sources. As stated earlier, in 2020 the Company updated its

HELM model to be sourced from actual hourly AMI data by customer class from the Company's service territory.

Q47. Has using AMI data yielded any improvements to the forecast models?

A47. Yes. For example, in the residential sales model, the MAPE has improved. The years 2006-2014, which utilize billing data, have a MAPE of 3.1% while the years 2015-2021 have a MAPE of 1.2%, yielding nearly a 2% improvement in the model performance.

In general, AMI data is a much cleaner data source in that it is the purest measurement of customer consumption, whereas billing data may include irregularities such as billing adjustments, canceled bills or late bills.

Q48. Why doesn't the Company use daily or hourly models for the annual long-term sales forecast?

A48. While the Company does utilize the HELM model, which is foundationally built on hourly AMI data to scale the annual long-term sales to produce an 8,760 and peak demand forecast, the broader long-term forecast is still performed at a monthly granularity. The Company's objective is to be able to build daily or hourly models as the basis for the annual long-term sales forecast. While the Company does have daily class level models for month-ahead forecasts, it is not yet feasible to rely on these models for long-term sales forecasting due to the limited available history of AMI data. Long-term sales forecasting relies on a deeper history of data to make accurate projections 10 years or more into the future. Given that the longest history of AMI data available is just over six years, it would be challenging to incorporate variables that measure structural changes in energy-use such as economic fluctuations and changes in end-use efficiency and yield statistically significant results. Put simply, the current daily class level models are only capable of forecasting short-term drivers of load such as weather. Given that structural changes are the basis for long-term forecasts it would not be prudent for the Company to use a model that doesn't yield statistically significant results when those drivers of change are included.

Many long-term forecast models use at a minimum 10 years of history, with some going as far back as 20 years or more. As the Company's library of AMI data continues to develop a richer history it will continue to update stakeholders on the progress of using more granular data to do long-term sales forecast.

<u>Section II: Recommendations from Case No. U-20633</u>

Q49. In Case No. U-20633, the Commission ordered a collaborative to outline ways to align distribution plans with integrated resource plans. Were there any recommendations related to load forecasting improvement?

A49. Yes. On pages 15-19 of the Commission's order in Case No. U-20633 the Commission approved Staff's recommendations on load forecasting as outlined in the Staff's May 27, 2021 report. Specifically, the Commission recommended the following:

- Increase the granularity of data used in load forecasts to properly account for all the value streams around distributed energy resources (DERs)
- Utilize a componentized or modular approach to create load forecast, particularly around DER's

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- Have alignment around system-level forecasts for resource, distribution, and transmission planning.

I will discuss progress on each of these recommendations in greater detail.

Q50. Pertaining to the first recommendation in Case No. U-20633, has the Company made progress to utilize more granular data in its forecast models?

A50. Yes. Please refer to questions and answers 46-48 of my direct testimony. I discuss in further detail the Company's current status on utilizing more granular data in the forecast models.

Q51. Pertaining to the second recommendation in Case No. U-20633, is DTE Electric taking a componentized approach to the load forecast?

A51. Yes. In general, the Company has been taking a componentized approach by having isolated technology forecasts for items such as EV adoption and DG adoption for many years. As more technologies that have the potential to impact load reach relevancy, the collection of forecasting components will continue to grow, and the Company is well positioned to include them in the load forecast.

As discussed earlier in my testimony, the Company currently produces separate forecasts for the following that are then included in the total load forecast:

- EVs
- EWR
- DG

- End-use level projections (including heat pumps) to enable forecasted growth in fuel switching of appliances or electrification

Having this modularity in the forecast enables flexibility when creating alternative forecasts for resource and distribution planning, such as the ones performed for this instant case.

Q52. What are the benefits to taking a componentized approach to load forecasting?

A52. As stated earlier in my testimony, having individual components of change in the forecast promotes better clarity into the drivers of change, provides more flexibility when developing alternative forecasts, and allows for modeling load shape diversity when forecasting peak demand and hourly loads.

For example, having an explicit forecast for EVs combined with a unique charging load shape enables the ability to model varying levels of EV adoption and the impacts to hourly consumption, changing peak demands, and shifts in peak hours.

Q53. Pertaining to the third recommendation in Case No. U-20633, what enhancements are being developed by the Company to align resource, distribution, and transmission planning?

A53. As discussed on page 66 of the Company's Distribution Grid Plan in Case No. U-20147, the Company is actively working to develop an integrated forecasting solution (IFS) to align distribution and generation forecasting. Historically, system-level forecasting for generation has been isolated from distribution planning due to the complexity and spatial requirements to perform distribution-level forecasts.

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While distribution-level forecasts have been performed, they have done so spatially at the substation or circuit level but only for the substation or circuit's single annual peak demand. Circuit peak demands and load patterns have the potential to change over time due to the dynamic characteristics of technologies such as EVs and DG, creating the need for a more robust approach to distribution forecasting.

The load forecasting team is pursuing the capability to conduct 8,760 hourly load forecasts at the substation and circuit-level to help analyze and address grid impacts from these evolving technologies. The bottom-up substation and circuit-level forecasts produced for distribution planning will be calibrated to the bottom-up hourly system-level forecast used in IRPs. While resource and distribution planning both require unique forecast outputs, the Company believes the forecast for both should be driven by consistent inputs, thereby improving alignment across business units within the organization. Ultimately, the IFS will deliver not only forecasts that mirror each other, but drive consistency across planning processes.

Q54. What is the current status on the efforts to develop the IFS tools and capabilities?

A54. The Company's plan includes a three-phase approach to developing the IFS and resulting distribution-level load forecast.

1. Phase one includes enhancements to the existing modeling capabilities and functionality for DTE Electric's system level forecasts to enable distribution load forecasting.
2. Phase two includes additional core modeling enhancements at more granular levels, data collection, cleansing and validation, and implementation of a

software platform capable of processing an hourly level for all DTE Electric substations and circuits.

3. Phase three will include validating the models, refinement, calibration schemes to the system-level forecast and other potential enhancements.

The Company began work in the first phase in 2021 and has since then completed it. Elements of the second phase have begun in 2022 and are currently in progress. Phase three is dependent on the completion of phase two. Completion of phase two and phase three will be determined by availability and access to quality data, resources, training, and initial model performance.

Part IV: Historical and Forecast Electric Sales, Demand, and System Output

Q55. What has been the CAGR of DTE Electric sales over the last five years?

A55. As shown in Exhibit A-10.1, weather normalized service area sales from 2017 to 2021 have declined overall during the five-year historical period. In 2017, total service area sales were 47,519 GWh and 2021 sales were 45,482 GWh, representing a CAGR of -1.1%. The main reasons for the decline were EWR impacts and effects of COVID-19 present in 2020 and 2021.

Bundled sales have decreased from 42,699 GWh in 2017 to 41,126 GWh in 2021, representing a CAGR of -0.9%. The electric choice sales declined from 4,820 GWh in 2017 to 4,357 GWh in 2021 by an average annual decrease of 2.5%. Refer to Exhibit A-10 for additional detail regarding historical actual sales for the service area, bundled and electric choice.

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Q56. What has been the CAGR of DTE Electric peak demand over the last five years?

A56. As shown in Exhibit A-10.1, weather normalized service area peak demand from 2017 to 2021 decreased during the five-year historical period. In 2017, total service area peak demand was 11,362 MW and 2021 peak demand was 11,358 MW, representing a CAGR of -0.01%. From 2017 to 2021 bundled peak demand decreased from 10,592 MW in 2017 to 10,552 MW in 2021 at a CAGR of -0.09%. Refer to Exhibit A-10 for additional detail regarding historical actual peak demand for service area, bundled and electric choice.

Q57. What is the CAGR of the DTE Electric service area electric sales in the Starting Point over the forecast period?

A57. In the Starting Point sales forecast as shown in Exhibit A-10.3, service area sales are expected to be 45,230 GWh in 2023 and increase to 49,469 GWh in 2042. This represents a 0.5% average annual increase.

Q58. What is the CAGR of DTE Electric bundled electric sales in the Starting Point over the forecast period?

A58. The bundled sales in the Starting Point are projected to increase over the forecast period. In 2023, sales are expected to be 40,629 GWh and increase to 44,531 GWh in 2042 as shown in Exhibit A-10.3. This represents a 0.5% average annual increase. The long-term growth rate for DTE Electric bundled sales is the same as the growth rate for service area sales due to steady Electric Choice sales.

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Q59. What is the forecast for Electric Choice sales for 2023 through 2042 in the Starting Point?

A59. The electric choice sales in the Starting Point are projected to increase over the forecast period due to increasing service area sales. In 2023, sales are expected to be 4,602 GWh and increase to 4,937 GWh in 2042 as shown in Exhibit A-10.3.

Q60. What is the outlook for residential class sales in the Starting Point?

A60. DTE Electric's service area residential class sales in the Starting Point case will increase 0.9% annually, on average, from 2023 through 2042. Modest average annual growth of 0.3% in residential customer count is expected through 2042 due to a moderating housing market. Annual customer counts are shown in Exhibit A-10.6. Use-per-customer through 2042 is expected to increase by 0.6% annually on average. Growth in residential use-per-customer is primarily driven by the projected increases in electric vehicle demand, modest increases in heating load from growth in heat pumps, and continued growth in miscellaneous electric loads. This growth is partially offset by increases in efficiency gains in air conditioning, appliances, and increases in solar PV adoption.

Q61. What is the outlook for small C&I sales in the Starting Point?

A61. DTE Electric's service area small C&I class sales in the Starting Point case will increase 0.8% annually, on average, from 2023 through 2042. Modest average annual growth of 0.3% in small C&I customer count is expected through 2042, similar to residential customer growth. Use-per-customer through 2042 is expected to increase by 0.5% annually on average. Growth in the small C&I use-per-customer is primarily driven by the projected increases in electric vehicle demand

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from public charging infrastructure. Most other end-uses are declining or stable due to any increases in end-use consumption from economic growth being offset by more efficient equipment.

Q62. What is the outlook for large C&I in the Starting Point?

A62. DTE Electric's service area large C&I class sales are expected to decrease by 0.1% annually, on average, from 2023 through 2042. As mentioned previously, large C&I class sales are allocated between seven supersector markets. Out of the seven supersectors, TTU, offices, other markets, automotive and other manufacturing are all declining or flat due to any increases from economic growth being constrained by energy efficiency efforts. Education & health is increasing due to rising employment and steel is projected to remain flat due to consistent operations. Table 4 provides a view of each supersector sales' forecasted growth rates.

Table 4: Supersector Sales 2023-2042 CAGR

Supersector	2023-2042 Sales CAGR
Education & Health	0.6%
Trade, Transportation & Utilities (TTU)	-1.3%
Offices	-0.1%
Other Markets	-0.6%
Auto	0.0%
Other Manufacturing	-0.4%
Steel	0.0%
Total Large C&I	-0.1%

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Q63. What is the outlook for Other Class sales in the Starting Point case?

A63. DTE Electric's service area Other Class sales in the Starting Point case are expected to decrease 0.1% annually, on average, from 2023 through 2042. The Other Class consists of street lighting and traffic signals. The main reason for the decline in sales is the use of more energy efficient lighting.

Q64. What is the CAGR of the DTE Electric service area system peak demand in the Starting Point case over the forecast period?

A64. As shown in Exhibit A-10.3, DTE Electric's forecast service area peak demand in the Starting Point increases from 11,250 MW in 2023 to 11,836 MW in 2042, representing an average compound annual growth rate of 0.3%. The increase in peak demand is mainly due to an increase in electric vehicle adoption.

Q65. What is the CAGR of the DTE Electric bundled peak demand in the Starting Point over the forecast period?

A65. As shown in Exhibit A-10.3, DTE Electric's bundled peak demand forecast for 2023 is 10,437 MW and increases to 11,016 MW in 2042, an average compound annual growth rate of 0.3% is expected. The long-term growth rate for DTE Electric bundled peak demand is the same as the growth rate for service area peak demand due to relatively steady Electric Choice sales.

Part V: Electric Load Forecast Alternatives

Q66. Did you prepare alternate load forecasts for this proceeding?

A66. Yes, I prepared nine alternative forecasts as shown in Exhibit A-10.4. The alternative forecasts developed are:

1. High Load Growth – Required based on the Michigan Integrated Resource Planning Parameters (MIRPP) requirements to assess the impacts of either double the growth present in the Starting Point or a 1.5% growth rate on energy and peak demand.
2. Return of 50% Retail Choice Load – Required based on the MIRPP requirements to model the return of 50% of the retail choice load to the utility's capacity service by 2023.
3. Aggressive Customer Owned Distributed Generation – Performed to assess the impacts of higher penetration levels of behind-the-meter solar photovoltaics.
4. High Electrification – Modeled to understand the impacts of higher adoption rates of electric vehicles and heat pumps in the Company's service area.
5. Stakeholder – Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles.
6. Stakeholder with 25% Distributed Generation growth through 2030 – Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles as well as aggressive customer owned behind-the-meter solar adoption.
7. Stakeholder with High Fuel Switching - Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles as well as high levels of fuel switching in residential and commercial buildings from natural gas end-uses to electric.
8. Electric Choice Cap Increases to 15% - Developed through the stakeholder collaboration process to assess the impacts of increasing the retail open access cap from 10% to 15%.

9. Climate Change – Performed to assess the impacts rising trends in temperature would have on energy and peak demand.

Q67. What assumptions are used in the High Load Growth sensitivity?

A67. The High Load Growth sensitivity was a required sensitivity based on the MIRPP requirements as defined in section 6t of 2016 PA 341. The assumptions used in the High Load Growth sensitivity were described on page 16 of the parameters[3] which states,

"Increase the energy and demand growth rates by at least a factor of the two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business as usual load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity."

Because doubling the overall growth rate would result in less than 1.5% growth, all growth rates were set to 1.5% excluding technologies including EVs and solar PVs. Setting the new technologies growth rate to 1.5% would severely under forecast the growth of the technologies relative to the Starting Point. Conversely, increasing the new technologies growth rate by a factor of two would result in overly far-fetched growth rates. Therefore, the new technologies' growth rates were left the same as the Starting Point.

Q68. What assumptions are used in the Return of 50% of Retail Choice Load sensitivity?

[3] Exhibit A, Order issued 11/21/2017 in MPSC Case No. U-18418, page 16.

A68. The Return of 50% of Retail Choice Load sensitivity is another sensitivity that was required in the MIRPP. The parameters state, "*If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by 2023.*"

Q69. What assumptions are used in the Aggressive Customer-Owned Distributed Generation sensitivity?

A69. The aggressive customer owned DG sensitivity was based on the Reference case and utilized an aggressive scenario for behind-the-meter solar photovoltaic adoption produced by ICF Resources LLC. Solar system capital costs were set to align with NREL's 2021 Annual Technology Baseline aggressive scenario.

Q70. What assumptions are used in the High Electrification sensitivity?

A70. To align with the draft MI Healthy Climate Plan,[4] this scenario assumes 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales are electric by 2030. Additionally, it is assumed that there are increased incentives around existing programs to turn over baseboard, propane and fuel oil systems and replaced with heat pumps quicker.

Q71. What assumptions are used in the Stakeholder scenario?

A71. This scenario was developed through the stakeholder collaboration process to assess the impact of higher penetrations of EVs. The assumptions are the same as in the High Electrification case as it relates to EVs with 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales being

[4] https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588, accessed October 20, 2022

electric by 2030. Various sensitivities were then applied to this Stakeholder scenario as discussed below.

Q72. What assumptions are used in the Stakeholder with High Distributed Generation sensitivity?

A72. This sensitivity was also developed through the stakeholder collaboration process to assess the impacts of both aggressive DG adoption and increased penetration of EVs. The Stakeholder scenario was used as the basis for this sensitivity and included 25% annual growth of DG from 2023-2030 and 15% annual growth from 2031-2042.

Q73. What assumptions are used in the Stakeholder with High Fuel Switching sensitivity?

A73. This sensitivity was also developed through the stakeholder collaboration process to assess the impacts of both increased EV penetration and high levels of fuel switching from natural gas end-uses to electric. The Stakeholder scenario was used as the base and included aggressive building electrification assumptions. Residential customers adopt heat pumps for heating as well as heat pump water heaters at a rate of 30% saturation and 50% saturation by 2030 and 2042 respectively. Small C&I customers are fully electrified at a rate of 20% saturation and 50% saturation by 2030 and 2042 respectively.

Q74. What assumptions are used in the Electric Choice Cap Increase to 15% sensitivity?

A74. An additional sensitivity was also developed through the stakeholder collaboration process to assess the impact of increasing the retail open access cap from 10% to 15% by June 1st, 2024. New Electric Choice customer enrollments were assumed to begin in March 2024 which is when the new choice load was assumed to begin in 2024. The full year of 15% Choice is reflected in 2025.

Q75. What assumptions are used in the Climate Change sensitivity?

A75. The climate change sensitivity was performed to assess the potential impacts on electricity consumption through trends in temperatures and uses the reference case as the starting point. Trends in temperature from 1960-2021 were applied to the normal weather assumed in the starting point. The increasing temperature trend was applied in the form of CDDs and HDDs to project changes in load. The results indicated annual increases in CDDs and annual decreases in HDDs, which results in higher summer loads and lower winter loads.

Q76. Does this complete your direct testimony?

A76. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHAWN D. BURGDORF

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF

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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. What is your current position with the Company?

A2. I am currently the Manager of the Power Supply Strategy & Modeling team within the Generation Optimization department.

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. Do you hold any certifications?

A4. 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 Michigan State University.

Q5. What is your work experience?

A5. 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.

Q6. What are your duties and responsibilities in your current position?

A6. My current responsibilities include acquisition of wholesale electric power supply to reliably and economically serve the energy requirements of the Company's customers including: optimization of the Company's generation assets, including renewable energy facilities, within the wholesale power market; management of emission allowance procurement; management of resource adequacy processes; modeling the DTE Electric generation fleet; optimizing financial transmission rights; and review and advocacy of Company recommendations regarding proposed MISO rules, regulations, and business practices.

Q7. Have you previously provided testimony before the MPSC?

A7. Yes. I sponsored testimony in the following MPSC 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 Main Rate Case
U-20528	DTE Electric’s 2020 PSCR Reconciliation
U-18091	DTE Electric’s 2021 PURPA Avoided Cost
U-20836	DTE Electric’s 2022 Main Rate Case

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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:

I. an overview of the resource adequacy requirements and capacity market,

II. support of the Company's existing capacity resources including Power Purchase Agreements (PPA) counted by Midcontinent Independent Transmission System Operator, Inc. (MISO) for planning year 2022/2023,

III. an overview of demand response resource accreditation within MISO's resource adequacy construct,

IV. an overview of the effective capacity import limit (ECIL) for MISO Zone 7,

V. an overview of the MISO Zone 7 capacity position for Planning Year 2022/23 as well as forecasted capacity positions for 2023/24, 2024/25, 2025/26, 2026/27 and 2027/28, and

VI. an overview of current MISO market-compensated Ancillary Services.

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 effective capacity import limit (ECIL) for MISO Zone 7 and discussed the risks of relying on external capacity imports.

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Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-11	DTE Electric Existing Capacity Resources
A-11.1	MISO's Post PRA Presentation on 4-14-2022
A-11.2	OMS-MISO Survey Results 6-10-2022
A-11.3	MISO's Detailed 2022-23 PRA Results 6-25-2022

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	Overview of the Resource Adequacy Requirements and Capacity Market
Part II	Company's Existing Capacity Resources Including Power Purchase Agreements
Part III	Overview of Demand Response/Load-Modifying Resources (LMRs) Accreditation in the MISO Resource Adequacy Construct and DTE Electric's method of purchasing energy rather than relying on demand response
Part IV	Overview of the Effective Capacity Import Limit (ECIL) for MISO Zone 7

[1] Exhibits 11.1, 11.2, and 11.3 were created under my supervision, however the content of the exhibits was created by MISO

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Part V Overview of the MISO Zone 7 Capacity Position for Planning Year 2022/23 and Forecast for Planning Years 2023/24, 2024/25, 2025/26, 2026/27, and 2027/28

Part VI Overview of Current MISO Market-Compensated Ancillary Services

I. Overview of the Resource Adequacy Requirements and Capacity Market

Q13. Who establishes the resource adequacy planning requirements with which the Company must comply?

A13. Resource adequacy requirements are governed by a combination of the North American Electric Reliability Corporation (NERC), MISO, and the Michigan Public Service Commission (MPSC). The MISO tariff requires the Company to develop a resource adequacy plan that complies with the reliability standards set forth by NERC. NERC Standard BAL-502-RFC-02 "Planning Resource Adequacy Analysis, Assessment and Documentation" requires the Planning Coordinator to calculate a planning reserve margin for each planning year. MISO is the Planning Coordinator for the Midcontinent ISO region. MCL 460.6w (PA 341) requires the Company to demonstrate, annually, that it will have sufficient resources to meet its projected planning reserve margin on a four-year forward basis. This Michigan requirement is intended to ensure proper longer-term planning for resource adequacy, which is not the case with MISO's one-year annual planning cycle as further discussed in my testimony.

Q14. How are capacity planning reserve margin requirements established by MISO?

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A14. Each year, MISO establishes a Planning Reserve Margin (PRM), which is the amount 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 and 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 standard in the industry.

Q15. How does MISO implement its resource adequacy requirements?

A15. MISO's resource adequacy requirements are annual and implemented for the immediately upcoming planning year only. Every year, Load Serving Entities (LSE) 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. The PRMR compliance process is executed by MISO in the spring immediately prior to the planning year 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 (PY) 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.

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. 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

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capacity that a LRZ can import can be constrained further than the CIL resulting in an effective CIL (ECIL), which is calculated by the following formula: ECIL = PRMR - LCR. 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).

Q17. How is MISO's annual resource adequacy construct expected to change in the future?

A17. MISO filed with the Federal Energy Regulatory Commission (FERC) tariff changes to alter its resource adequacy construct from an annual to a seasonal approach (spring, summer, fall and winter) and incorporate planned outages performance under tight system hours as part of the capacity resource accreditation. The seasonal approach will be similar to the annual construct with a single PRA that solves for each season. Each season will have different CIL, CEL, LCR, local reliability requirement (LRR) and PRMR values as well as resource accreditation tied to the seasons. This will likely impact resource outage planning and provide a more granular focus on resource adequacy across the entire PY. The Seasonal Accredited Capacity filing (Docket No. ER22-495) was approved by FERC on 8/31/22 with MISO requesting the implementation starting with PY 2023/2024. Due to the timing of the FERC approval and the limited information the Company has received from MISO, the Company does not have an accurate Zone 7 capacity forecast under the new construct prior to this case filing. Witness Mikulan further discusses how the IRP modeling accounts for ensuring year-round resource adequacy for DTE Electric customers.

MISO has recently started to discuss, through the stakeholder process, further changes to how accreditation is done for non-thermal (including intermittent and DR) resources. Preliminary discussions indicate a potential negative accreditation impact on these types of resources in the future, though impact will vary by resource-type and season.

II. Company's Existing Capacity Resources Including Power Purchase Agreements

Q18. How are capacity resources recognized in meeting reliability requirements?

A18. MISO uses unforced capacity (UCAP) to determine the amount of capacity from a capacity resource to credit towards reliability requirements in each planning year. UCAP is intended to represent the amount of capacity that is expected to be available for that resource during MISO's summer peak demand based on its operating characteristics and historical performance. UCAP values for non-intermittent resources are currently calculated by reducing the resource's installed/tested capacity (ICAP) by its three-year historic forced outage rate. UCAP values for non-wind intermittent resources, such as run of river hydro and solar, are currently determined based on actual output during the hours ending 15, 16, and 17 during all days of June, July, and August of the most recent three years. UCAP values for wind resources are currently based on their average historical output during each of MISO's eight highest coincident peaks that occurred during the

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summer as well as an annual MISO study of the Effective Load Carrying Capability (ELCC) for wind resources throughout the footprint. 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. Since DR and Load Modifying Resources reduce demand at the point of customer interconnection, UCAP is determined by increasing the interruptible demand by the Local Balancing Authority's transmission loss percentage as well as the MISO PRM.

Q19. What existing capacity resources did the Company commit to MISO for planning year 2022/2023?

A19. Exhibit A-11 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 9,741 MW of MISO Planning Resources in the 2022/2023 planning year using the UCAP methodology. The Company's current DR resources qualified for 878 MW of MISO Planning Resources in the 2022/2023 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 D5 Interruptible Hot Water Heating Service Rate, 4) Tariff D8 Interruptible Supply Rate, 5) Tariff R1.1 Alternative Electric Metal Melting, 6) Tariff R1.2 Electric Process Heat, 7) Tariff R10 Interruptible Supply Rider, 8) Tariff R12 Capacity Release, 8) Tariff D1.8 Smart Currents, and 9) Bring Your Own Device. The Company's current long-term

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Power Purchase Agreements (PPAs) qualified for 159 MW of MISO Planning Resources in the 2022/2023 Planning Year and include both Public Utility Regulatory Policies Act (PURPA) and PA295/PA342 resources. The accredited value of capacity resources varies slightly from year to year based on unit performance and MISO's UCAP methodology.

Q20. How long does the Company project to purchase power from its Long-Term Power Purchase Agreements?

A20. Exhibit A-11 shows the Company's Long-Term Power Purchase Agreements and the year in which each agreement terminates. However, for planning purposes, 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.

III. <u>Overview of Demand Response/Load-Modifying Resources (LMRs) Accreditation in the MISO Resource Adequacy Construct</u>

Q21. How are DR resources currently accredited under the MISO Resource Adequacy Construct and what has changed with the accreditation in the recent past?

A21. In August 2020, FERC accepted a Tariff filing to incentivize DR resources to have shorter notification times and increased call limits. DR resources offered in the 2022/23 PY needed a notification time of six hours or less and they must respond to up to ten interruptions per year (if needed) to receive full accreditation. Resources that were only available for five to nine calls per year would receive 80% of the accredited capacity, and resources available for less than five calls or greater than six-hour notification times did not qualify as capacity resources. These changes were implemented to ensure DR resources are available when needed during emergency conditions. Prior to making the FERC filing, MISO noted "a significant gap between the full capacity credit currently being received by LMRs and the actual hourly availability being reported to MISO." [2]

Q22. Do you anticipate any further changes to the DR accreditation?

A22. Yes, as noted above, on 8/31/22 FERC approved MISO's Seasonal Accredited Capacity proposal. Beginning in the PY 2023/24, the number of interruptions will increase from up to ten per year to up to sixteen per year, with seasonal interruption requirements. 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.

Q23. Are you concerned about future DR accreditation changes as well as the generation transformation occurring across MISO having an impact on the ability to increase the level of DR resources in this IRP?

A23. Yes. As previously discussed, MISO has already made changes to demand response accreditation that requires shorter notification times and increases the number of times that DR resources can be interrupted per year to receive full accreditation. The generation transformation occurring across MISO has shown that total resource accredited amounts have dropped over the last few PYs (see Exhibit A-11.1, slides 7 and 8), however, accredited DR resources have remained relatively flat (see Exhibit A-11.1, slide 22). MISO stated that "Load Serving Entities' reliance on

[2] MISO Filing to Enhance Accreditation of Load Modifying Resources Participating in MISO Markets, ER20-1846 (pg. 11)

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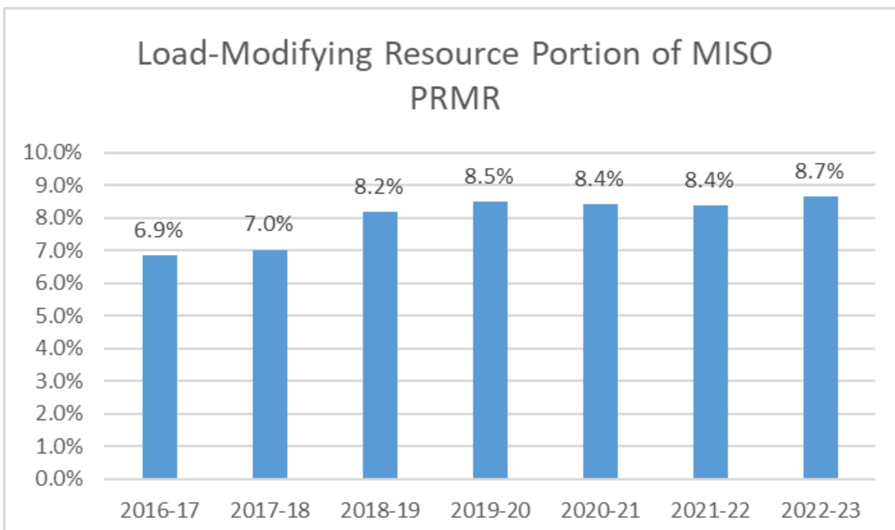
LMRs to meet their Planning Reserve Margin Requirements ("PRMR") has never been greater, with LMRs making up nearly 9% of MISO's PRMR."[3] As shown in Figure 1 below, MISO has seen a steady increase in LMRs and DR resources being used to meet the PRMR over the last several years. The North/Central regions show an even more extensive reliance on LMRs, making up 12.2% of their PRMR compared to 8.7% MISO-wide. Thus, the future expectation is that DR resources will be utilized to a greater extent as their percentage of the resource mix increases.

Figure 1: Portion of MISO PRMR met by Load-Modifying Resource



1) Data from MISO PRA results

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 Farrell for additional information on DR programs.

[3] MISO Filing to Enhance Accreditation of Load Modifying Resources Participating in MISO Markets, ER20-1846 (pg. 3)

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 Sections 69A.3.9a and 69A.3.9b of the MISO Tariff, if a DR resource does not respond to an interruption request, "if deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG [Behind the Meter Generation] from further use as an LMR for the remainder of the current Planning Year." If that same DR resource is unavailable for a second occasion, "the Demand Resource or BTMG will no longer qualify as an LMR and will not 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." Most new generation resources take multiple years to bring online, thus, disqualifications of demand response resources and/or customers dropping out of existing programs planned to meet resource adequacy targets creates a reliability risk. As discussed by Witness Farrell, the Company will monitor customer participation and performance.

IV. Overview of the Effective Capacity Import Limit (ECIL) for MISO Zone 7

Q24. What was the PY 2022/2023 Zone 7 ECIL and how did it limit Zone 7 capacity imports?

A24. Based on MISO's resource adequacy requirements for PY 2022/23, 97% of the PRMR applicable to load serving entities in Michigan Zone 7 must be supplied by resources located within the zone. For PY 2022/23, the Zone 7 ECIL was 657 MW (ECIL = PRMR – LCR = 21,886 – 21,229 = 657 MW using MISO PRA data published 4/14/22). Thus, while the capacity import limit was 3,749 MW, in reality, only 657 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.

Q25. How has Zone 7 ECIL changed over the past four Planning Years and the percentage of PRMR needed to come from local resources?

A25. 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 federal reliability standards in recent years has not dropped below 91.8% showing the importance of generation built within Zone 7.

Table 1: Zone 7 Historical ECIL and percentage of local resources required by Planning Year (in MWs)

Description	PY 2019/20	PY 2020/21	PY 2021/22	PY 2022/23
Zone 7 ECIL[1]	164	94	1,749	656
Local Requirement as percentage of PRMR[2]	99.3%	99.6%	91.8%	97.0%

1) Data from actual MISO PRA results
2) Local Requirement as percentage of PRMR calculated by dividing LCR by PRMR.

Q26. Do you have concerns about relying on imports and the ability to import capacity external to Zone 7?

A26. 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

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as there is no obligation by individual LSEs to ensure their share of the local reliability criteria is met.

The most recent MISO Planning Resource Auction for PY 2022/23 also showed that even when the ECIL was sufficient to import capacity, there were not enough resources external to Zone 7 available. Zone 7's capacity shortfall to the PRMR, combined with shortfalls in other zones, resulted in the entire MISO North-Central region clearing at CONE (see Exhibit A-11.1, slide 4) and demonstrates further risk of relying on external Zone 7 resources.

In addition, MISO has rules for external resources, such as those in Ontario, that ensure reliability. Ontario rules would need to improve 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

[4] MISO Tariff Module E-1 69A.3.1.c (p. 40)
[5] MISO Tariff Module E-1 69A.3.1.f (p. 50)

with the recall standards as established by MISO, thus disallowing its capacity from qualifying in the MISO construct.

Q27. Do you have concern with increased costs of relying on resources external to Zone 7?

A27. Yes. Customers are exposed to the potential of 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 (cost of new entry) 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 customers load at the Company's load node (DECO.NEC) may not be offset by the market revenue (generator LMP) received by a generation resource located in another zone/area. This mismatch in cost/revenue can be large and is unpredictable.

V. Overview of the MISO Zone 7 Capacity Position for Planning Year 2022/23 and Forecast for Planning Years 2023/24, 2024/25, 2025/26, 2026/27, and 2027/28

Q28. How did you forecast the total Zone 7 resources from PYs 2023/24 to 2027/28?

A28. The most recent capacity demonstration report published on March 25, 2022 by the MPSC Staff in Case No. U-21099 was used as the basis for Zone 7 resource projections. This capacity demonstration report does not extend beyond Planning Year 2025/26, so I held the Zone 7 resources flat for the PYs 2026/27 and 2027/28. I then adjusted the capacity demonstration values for known DTE Electric capacity value changes and changes associated with the Consumers Energy IRP Settlement in Case No. U-21090.

I believe using a forecast created with assumptions under the current MISO resource adequacy construct provides a reasonable Zone 7 capacity position outlook. The new MISO seasonal resource adequacy construct changes, as previously discussed, create too many unknown variables to accurately forecast Zone 7 capacity until further information is published by MISO or produced through other public forums (e.g., capacity demonstration filing).

Q29. What is the MISO Zone 7 Local Reliability Requirement (LRR)?

A29. The LRR represents the minimum amount of unforced capacity for an LRZ to meet its LOLE without considering transmission ties to systems outside of the LRZ. The

LRR is a part of the equation to calculate the LCR. Holding all else equal, a higher LRR results in a higher amount of capacity resources required to be located in a MISO Zone. The equations for LRR and LCR are as follows:

LRR = (Per-Unit LRR) * Zonal Peak Demand

LCR = LRR – CIL – Non-pseudo tied exports

In recent years, there have been no non-pseudo tied exports in Zone 7 and the equation simplifies to LCR = LRR – CIL.

Q30. How has the Per-Unit LRR changed over the past few PYs and what is a reasonable forecast for PYs 2023/24 through and 2026/27?

A30. The Per-Unit LRR represents the LRR per unit of peak demand. The historical Per-Unit LRR values for the past few PYs are shown in Table 2. The Per-Unit LRR has shown an upward trend from 115.3% in Planning Year 2018/19 to 119.4% in the most recent 2022/23 PY.

Table 2: Zone 7 Historical Per-Unit LRR by Planning Year

Description	2018/19	2019/20	2020/21	2021/22	2022/23
Zone 7 Per-Unit LRR[1]	115.3%	117.2%	119.5%	121.2%	119.4%

1) Source: MISO LOLE reports published for corresponding Planning Years

There are many factors that MISO considers in its LOLE analysis when determining reserve margins, which include weather and economic uncertainty, load, and generation. Even though the Per-Unit LRR dropped slightly from PY 2021/22, it has been trending upward in the recent past as shown in Table 2. I believe it reasonable to project a range using the current Planning Year 119.4% to the recent PY 2021/22 of 121.2% for the upcoming PYs 2023/24 through 2027/28.

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This range is possibly conservatively low and likely to increase with the generation transformation occurring in Zone 7 as further discussed by Witness Roy.

Q31. How did you project the Zone 7 Peak forecasted Demand for PYs 2023/24 through 2027/28?

A31. The Zone 7 peak forecasted demand was calculated by using the peak demand from the MISO 2022-23 LOLE Report as a baseline. DTE Electric's peak demand that was included in the LOLE report was then replaced with DTE Electric's most recent peak demand forecast in this case to get an adjusted Zone 7 forecasted peak demand.

Q32. Does DTE Electric believe the MISO Zone 7 CIL will change thru PY 2027/28 from the range of CIL values in the past six PYs (e.g., increase above maximum or decrease below the minimum CIL values)?

A32. No. Even though the historical CIL value has been volatile year over year, CIL is likely to stay within a similar range of values as shown in Table 3 as further discussed by Witness Roy. The Table 3 shows the variability in CIL values in recent years.

Table 3: Zone 7 Historical CIL value by Planning Year (in MWs)

Description	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Zone 7 CIL[1]	3,785	3,211	3,200	4,888	3,749	5,087

1) Source: MISO LOLE reports published for corresponding Planning Years

Q33. What is your projection of a reasonable range for potential MISO Zone 7 resources compared to the LCR and PRMR for Planning Years 2023/24, 2024/25, 2025/26, 2026/27 and 2027/28?

A33. Table 4 shows a range of MISO Zone 7 resource positions compared to the forecasted LCR and PRMR based on recent MISO data from the 2022 LOLE report, MISO's PRA results from PY 2022/23 and adjusting the MPSC Staff Report for Zone 7 capacity demonstrations in Case No. U-21099 for DTE Electric resource changes and estimated Consumers Energy resource changes.

Table 4: Zone 7 Resource Adequacy for Planning Year 2022/23 and forecasts for Planning Years 2023/24, 2024/25, 2025/26, 2026/27 and 2027/28

Line #	Description	PY 2022/23	PY 2023/24	PY 2024/25	PY 2025/26	PY 2026/27	PY 2027/28
1	Zone 7 Peak Demand (MW)[1]	20,920	20,942	21,258	21,607	21,521	21,386
2	LRR Unforced Capacity per-unit of Peak Demand	119.40%	119.4% - 121.2%	119.4% - 121.2%	119.4% - 121.2%	119.4% - 121.2%	119.4% - 121.2%
3	Local Reliability Requirement (LRR = Line 1 x Line 2)	24,978	25,005 - 25,382	25,382 - 25,765	25,799 - 26,188	25,696 - 26,083	25,535 - 25,920
4	Capacity Import Limit (CIL)[2]	3,749	5,087	3,200 - 5,087	3,200 - 5,087	3,200 - 5,087	3,200 - 5,087
5	Local Clearing Requirement (LCR = Line 3 - Line 4)	21,229	19,918 - 22,182	20,295 - 22,565	20,712 - 22,988	20,609 - 22,883	20,448 - 22,720
6	Zone 7 Resources (MW UCAP)[3]	21,489	22,638	22,864	22,221	22,579	22,578
7	LCR Position (Line 6 - Line 5)	260	456 - 2,720	299 - 2,569	(767) - 1,509	(304) - 1,971	(142) - 2,130
8	Anticipated LCR Position without Belle River (Line 7 - 1,215 MW UCAP)				(1,982) - 294	(1,519) - 756	(1,357) - 915
9	Planning Reserve Margin Requirement (PRMR)[4]	21,886	22,174	22,419	22,696	22,615	22,484
10	ECIL (Line 9 - Line 5)	656	(7) - 2,257	(146) - 2,124	(292) - 1,984	(268) - 2,007	(236) - 2,036
11	Anticipated PRMR Position without Belle River (Line 6 - Line 9 - 1,215 MW UCAP)				(1,689)	(1,251)	(1,121)

(1) Based on MISO 2022-23 Loss of Load Expectation Report including known DTE peak load changes
(2) Planning Year 2022/23 and 2023/24 are actual. Other years based on historic range of CIL values
(3) Planning Year 2022/23 is actual. Other years based on 2022-23 LOLE Study Report including known DTE resource changes and adjustments for Consumers IRP settlement
(4) Planning Year 2022/23 is actual. Other years based on 2022-23 LOLE Report adjusted for DTE peak load changes

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Q34. Do you have any concerns about relying on resources external to Zone 7?

A34. Yes. Table 4 shows the forecasted Zone 7 capacity position relative to the LCR and PRMR is tight in PYs 2025/26, 2026/27 and 2027/28. Any potential retirement of a Belle River Power Plant size generation asset (1,215 MW UCAP) during these PYs may drop the Zone 7 required resources below the LCR. Additionally, Zone 7 would likely be reliant on capacity imports as shown on Table 4, line 11. 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**. 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 current 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, it is not likely that they build excess generation due to MISO's 1-year capacity market.

Projections for PYs 2025/26, 2026/27 and 2027/28 in Table 4 show that Zone 7 would likely have to rely on imports of more than 397 MW without Belle River available as a capacity resource. 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 exceed the federal 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 eliminates this additional financial risk on our customers.

Q35. What is the significance of Zone 7 and/or the MISO region exceeding federal reliability standards that govern resource adequacy?

A35. 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. This is evidenced by the capacity shortfall in MISO North/Central regions in the 2022-23 PRA, which put those regions at a "slightly increased risk of needing to implement temporary controlled load sheds" (Exhibit A-11.1, slide 2). Rather than meeting the required 8.7% PRM, these regions had only a 7.7% reserve margin, putting the LOLE at 1-day in 5.6-years (Exhibit A-11.3, slide 4). Not meeting the federal standard increases the likelihood of using DR resources and the risk of outages due to a lack of capacity in those regions.

Q36. Do you have any other concerns about the timing of the generation transformation occurring across MISO and sustaining reliability over the next five years?

A36. Yes. Capacity projections from the 2022 OMS-MISO Survey show an increasing deficit of resources needed to meet reliability requirements if new resources are not brought online to replace retirements (Exhibit A-11.2, slide 5). With the MISO North-Central region already experiencing a capacity deficit in PY 2022 and the

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projection for deficits to continue over the next five years, it critical to properly plan for new generation assets to come online well in advance of any planned retirements or further increase the reliability risk to DTE Electric customers. From a pure economic sense, ideally new generation would 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 the large "excess generation" (generation in excess of requirements) available across MISO.

VI. Overview of Current MISO Market-Compensated Ancillary Services

Q37. Can you identify the compensation mechanisms for ancillary services that are currently recognized by MISO?

A37. 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 Operating Reserves (Regulating Reserve, Spinning Reserve, Supplemental Reserve, 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 Mikulan for discussion on incorporation of regulation and spinning reserve markets in the valuation of battery technologies in the IRP.

The Company's ancillary services that receive compensation through a MISO tariff rate (instead of a market) consist of Reactive Supply and Voltage Control, which provide the ability to maintain transmission system voltages within acceptable levels.

Q38. Can you describe each of the ancillary service products MISO administers?

A38. MISO administers Day-Ahead and Real-Time markets for Operating Reserves where each of the four operating reserve products are 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.

Reactive Supply and Voltage Control is supplied by facilities that can be operated to produce or absorb reactive power to control voltage on the system. The administration of this service is performed by MISO/ITC, where it is sold by qualified generators and purchased by transmission customers.

Q39. 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?

A39. 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 to incentivize resource attributes that were not a concern in the past. MISO has identified six reliability attributes[6] as initial priorities which include availability, fuel assurance, ramp up capability, voltage stability, rapid start-up and long duration energy at high output. MISO intends to develop and refine potential new products or requirements in the near term to address the reliability concerns.

MISO also intends to develop a reliability-based Demand Curve[7] that recognizes the incremental value of capacity above the 1 day in 10 LOLE standard. This supports and incentivizes a strategy to have surplus capacity supporting reliability and accounting for uncertainties as discussed by Witness Mikulan.

Q40. Does this complete your direct testimony?

A40. Yes, it does.

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[6] MISO Forward (misoenergy.org), https://cdn.misoenergy.org/20221012%20RASC%20Item%2008b%20System%20Attribute%20Overview%20Presentation626543.pdf

[7] Reliability Requirement Representations in the Planning Resource Auction: Consideration of a Reliability-Based Demand Curve (misoenergy.org), https://cdn.misoenergy.org/20221012%20RASC%20Item%2008a%20Reliability%20Based%20Demand%20Curve%20Presentation%20(RASC-2019-8)626583.pdf

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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SONJOY D. ROY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SONJOY D. ROY

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

A1. My name is Sonjoy Deb Roy, and my business address is: DTE Energy, One Energy Plaza, Detroit, MI 48226, USA. 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 Master of Science degree in Electrical Engineering in 2013 from the University of Calgary, Calgary, Alberta, Canada. I also received a Bachelor of Science degree in Electrical and Electronic Engineering in 2009 from Bangladesh University of Engineering and Technology, Dhaka, Bangladesh.

Q4. What work experience do you have?

A4. After pursuing my Masters from the University of Calgary I started my professional career with Teshmont Consultants LP as an Electrical Engineer in 2013. As part of a consulting group, I had the opportunity to work on numerous projects for several clients ranging from utilities, independent system operator (ISO), transmission owner, oil and energy production company, and renewable developer. My key responsibilities involved power system modeling, planning and reliability assessment studies, new generator interconnection studies for wind, solar, storage and gas fired generating facilities, reliability performance assessment studies for asset management, and technical support in utility regulatory filings. One of my major contributions was developing a highly sophisticated software program for the Alberta Electric Supply Operator (AESO) to implement incremental loss factor methodology to estimate annual loss factors for the generating services in Alberta.

In 2019, I was hired by an Oil & Energy production company, Syncrude Canada Ltd., as Senior Engineer in the Electrical & Instrumentation group under Equipment & Reliability Engineering Department. In this position my key responsibilities involved providing electrical engineering support for planned major and mini outages associated with gas turbine generators and other major equipment in the power generation and distribution area; providing technical support for incident investigations; developing specifications for electrical/control equipment; providing maintenance and test plans for major high, medium & low voltage electrical equipment; reviewing equipment test results; participating in hazard and risk assessment of various electrical equipment; managing Syncrude power system models, and performing arc flash hazard and short-circuit analysis. One of my major contributions was developing a sophisticated software program to automate Syncrude site-wide arc flash hazard analysis based on the up-to-date IEEE 1584-2018 standards.

In 2021, I accepted a position in DTE Energy as Engineer - Principal Specialist in the Transmission Optimization Group under Business Planning & Development.

Q5. What is your current position and what are your responsibilities?

A5. Currently I am a Principal Specialist Engineer in the Company's Transmission Optimization group. My responsibilities include:

- Analyzing, assessing, and validating transmission system reliability issues identified by the Midcontinent Independent Transmission System Operator (MISO) and local transmission system owners.

- Identifying robust engineering solutions to resolve transmission system reliability issues

- Estimating construction cost of technical solutions and developing the associated business case for selection over less optimal transmission solutions

- Leading generator interconnection studies and evaluating projects proposed by Transmission Owners to enable generator interconnections

- Leading efforts to develop plans to facilitate load interconnection projects

- Conducting studies and analyses in the resolution of engineering- related issue regarding reliability and operability of the bulk power transmission system

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to demonstrate how the electric transmission analysis performed in the Company's Integrated Resource Plan (IRP), as required by MCL 460.6t(5)(h), met all requirements of previous orders, and how it supports the proposed course of action (PCA). In my testimony I will provide the following:

- Details on our engagement with ITC Transmission (ITC) related to the IRP and the types of analyses that were performed by ITC in support of the IRP
- Implications to the Michigan transmission system based on the different cases studied and how they were considered in the IRP process and PCA, including grid infrastructure needs and the associated costs
- Description of the Capacity Import Limit (CIL) analysis and the anticipated effects of fleet changes proposed in the Company's IRP to the import capability of the lower peninsula of Michigan (i.e., MISO LRZ7)
- Description of additional transmission planning studies impacting the Company's IRP including any from the Midcontinent Independent System Operator (MISO).

Q7. Are you sponsoring any exhibits with your direct testimony?

A7. Yes. I am sponsoring the following exhibits:

Exhibit Description

Line No.

A-12.1	DTE Electric and ITC - Meeting Notes
A-12.2	ITC Study Scope for DTE 2022 IRP Transmission Analysis
A-12.3	ITC's DTE Electric IRP Transmission Analysis Memo
A-12.4	ITC CIL/CEL Analysis Report
A-12.5	LRTP Capacity Import Limit Analysis for Michigan

Q8. Were these exhibits prepared by you or under your direction?

A8. Yes, they were.

Q9. How is your testimony organized?

A9. My testimony consists of the following five (5) sections:

Section I	ITC Engagement and Analysis Definitions
Section II	Discussion of ITC Study Results
Section III	Consideration of studies on DTE Electric's IRP Process and PCA
Section IV	Discussion of the Capacity Import Limit (CIL) Analysis
Section V	Other Transmission System Studies

Section I: ITC 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 the local transmission owner, ITC Transmission (ITC or ITCT), a subsidiary of ITC Holdings Corp, a Fortis Company. ITC is a fully regulated company under the jurisdiction of the Federal Energy Regulatory

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Commission (FERC) that operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in the southeastern part of Michigan's lower peninsula. ITC Holding's transmission systems in Michigan include the ITCT and Michigan Electric Transmission Company (METC) transmission systems. METC operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in most of Michigan's lower peninsula.

Q11. What was the purpose of the engagement between ITC and DTE Electric?

A11. Part of the IRP statute, MCL 460.6t(5)(h), requires the utility to "include an analysis of potential new or upgraded electric transmission options for the utility." In addition, Subsection (j) requires the utility to include cost estimates for "any transmission and distribution infrastructure that would be required to support the proposed construction or investment and power purchase power agreements" for meeting current and future capacity needs. The Michigan Public Service Commission (MPSC), in orders issued in Case Nos. U-18419 (Certificate of Need for Bluewater Energy Center) and U-20471 (2019 IRP), also addressed its expectation for enhanced coordination of transmission and generation resource planning and collaboration between DTE Electric and ITC in future IRP processes.

In accordance with the statute and MPSC orders, DTE Electric engaged ITC to discuss the IRP and requested an analysis of the ITCT and METC transmission systems due to the potential changes to DTE Electric's generation fleet based on alternative retirement dates for the Monroe and Belle River power plants and other known changes in the state. The analysis was designed to include both generation

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and transmission considerations in the IRP process and includes cost estimates for new generation interconnections and associated transmission upgrades required to support the alternative retirement dates.

Q12. Can you summarize the IRP related interactions with ITC?

A12. Yes. From October 2021 through October 2022, DTE Electric collaborated with ITC over multiple meetings. See Table 1 below for the meeting dates and topics and Exhibit A-12.1 for the meeting minutes. In addition, the Company and ITC met informally several times during this same period. Meeting minutes were not developed for the informal meetings.

Table 1: List of Meetings between DTE Electric and ITC

Date	Summary of Key Meeting Items
10/21/2021	Reviewed MPSC filing requirements and feedback from the 2019 IRP order; ITC overview of modeling approach
11/10/2021	Reviewed IRP project timeline review
12/08/2021	Discussed DTE Electric's proposed scenarios and scope of transmission study
01/05/2022	Discussed studies, scope of work, timeline, and input assumptions
02/28/2022	Discussed studies, scope of work, timeline, and input assumptions
03/21/2022	Reviewed DTE Electric input assumptions to ITC and modeling approach; review IRP requirements

04/25/2022	Reviewed IRP filing requirements discussed transmission study progress
05/23/2022	Provided scope of work and DTE Electric input assumptions
06/21/2022	Discuss ITC's draft memo
08/05/2022	Discuss additional scenario, CIL study, scope of work, timeline, and input assumptions
09/29/2022	Discuss the results of the additional scenarios screening and the CIL analysis

Q13. How was ITC's scope of work defined?

A13. In October 2021, DTE Electric communicated its plans to file an updated IRP targeting October 2022. In January 2022, the Company provided preliminary assumptions for three generation scenarios to ITC. ITC then developed, in coordination with DTE Electric, a scope of work (SOW) for the analytical work that was to be completed. This initial ITC SOW was established on March 22, 2022, and is the basis for generation and transmission assumptions for this analysis. Minor revisions were subsequently made to the scope to accommodate and clarify information related to the transmission analysis and incorporated into the final SOW. The final version of the SOW is provided in Exhibit A-12.2.

Q14. What are the key elements of the analyses performed in the ITC evaluation of DTE Electric generation scenarios or cases?

A14. The analysis by ITC was designed to determine the nature and extent of transmission planning violations (e.g., voltage levels not meeting specified criteria) associated with changes in the generation resources (within in Zone 7) as well as estimates of the costs to resolve such violations and to interconnect new generation sources. In the analyses, ITC modeled snapshots of the transmission system representing summer peak and summer shoulder peak load conditions to evaluate key risk items. The 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 the National Electric Reliability Council (NERC) TPL (Transmission Planning) Standards.

The key analyses performed by ITC included the following:

- Steady state analysis – Thermal and voltage violations on the transmission system
- Stability analysis – Testing electrical system's ability to maintain generation and load balance (stay in synchronism) after major disturbances 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 additions of new resources
- New generation interconnection direct attachment facility cost estimation
- Capacity import limit (CIL) analysis – Impacts from DTE Electric's PCA to the capacity import capability of the lower peninsula of Michigan

I will describe the results of the analyses in more detail later in my testimony.

Q15. Can you briefly describe what a transmission steady state analysis is?

A15. The 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.

Q16. Can you explain both thermal and voltage violations?

A16. 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 thermal limits as defined by the transmission planning criteria set by the Transmission Owner (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 safety, 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 termed a voltage violation.

Q17. Can you briefly describe what a transmission stability analysis is?

A17. Yes. The transmission stability analysis determines the ability of the power system to maintain synchronism and return to an adequate steady state operation condition after a major disturbance occurs in the power system so that customers' power remains unaffected.

Q18. What scenarios were provided by DTE Electric to ITC for the transmission analyses?

A18. The Company provided three different scenarios for ITC to evaluate as set forth in the SOW. The scenarios were developed by the IRP team and contain varying assumptions for unit retirements and replacement generation.

1. **ITC Scenario-1**: Retire Belle River by 2028, then retire all four units of Monroe by early 2030's
2. **ITC Scenario-2a**: Retire Belle River by 2028, then retire two units of Monroe by early 2030s and the other two units by mid-2030s
3. **ITC Scenario-2b:** Convert Belle River to natural gas by 2028, then retire two units of Monroe by early 2030s and the other two units by mid-2030s. Retire converted Belle River by 2040.

In each of the three DTE Electric scenarios there are total retirements of ~4,100 MW with replacement resources consisting of ~7,300 MW solar, 2,000 MW storage and 1,500 MW of dispatchable resources over the 20-year study period. The low or zero carbon proxy dispatchable resources could be a gas combine cycle gas turbine (CCGT) with carbon capture and sequestration (CCS), hydrogen fired CCGT, small modular nuclear reactor (SMR) or some other dispatchable resource. See Exhibit A-12.2 for additional detail on the scenarios.

The key difference between the scenarios is the timing of the retirements and replacement resources, and the conversion of Belle River from a coal-fired plant to natural gas peaking resource in one scenario. The development of the scenarios is further discussed by Witness Mikulan in her testimony.

Q19. Did the Company request an additional ITC scenario?

A19. Yes, a fourth scenario, referred to as ITC Scenario-3, based on ITC Scenario-1, was requested in August 2022 to analyze the steady state impacts of additional wind, solar, storage, and demand response in place of the proxy dispatchable resource (previously a CCGT with CCS) when Monroe Power Plant was fully retired in the 10-year time frame. Refer to Witness Mikulan for additional details on the development of this scenario.

Q20. Can you describe the transmission system models used by ITC?

A20. MISO annually develops a series of transmission system models with different planning (time) horizons in each MISO Transmission Expansion Plan (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 MTEP21 series of models. The available transmission models in the MTEP21 series of models were the 1-year (2022), 2-year (2023), 5-year (2026) and 10-year (2031) models. ITC used the 10-year (2031) transmission model to develop the 15-year (2036) and 20-year (2041) models for the IRP study. The first three scenarios described above were evaluated across four different years (i.e., 5, 10, 15 and 20 years) and two snapshots for each year (i.e., summer peak and summer shoulder conditions). ITC adjusted the generation profile in the transmission models for both DTE Electric and the rest of MISO Zone 7 (including the Consumers Energy footprint) using the build plans developed by the IRP Team as described by Witness Mikulan.

Q21. How did ITC model the initial scenarios in the steady state analysis?

A21. Based on the three initial scenarios provided by DTE Electric, ITC selected one year during each 5-year period over the 20-year study time frame to analyze a snapshot of the system within the range of potential retirement dates for the applicable units. See below for the retirement years assumed in the steady state analysis to represent the scenarios provided by DTE Electric, as I previously discussed .

1. **ITC Scenario-1**: Retire Belle River in year 5 and retire all four units of Monroe in year 10
2. **ITC Scenario-2a**: Retire Belle River in year 5, then retire two units of Monroe in year 10 and the other two units in year 15
3. **ITC Scenario-2b**: Convert Belle River to natural gas peaking resource in year 5, then retire two units of Monroe in year 10 and the other two units in year 15. Retire the converted Belle River in year 20.

The generation replacements were aligned to these four timeframes as well. See Exhibit A-12.2 for additional detail on the generation replacement assumptions for each ITC Scenario.

Q22. How were the generation replacement resources sited in the model?

A22. DTE Electric provided ITC with siting assumptions for the replacement generation to include in the modeling over the 20-year study period. Siting was determined as described below:

- Approximately 7,300 MW Solar: This group was assumed to have 6,550 MW connected to the transmission system and 750 MW connected to the subtransmission system within DTE Electric's distribution system based on available injection capacity of the lines and subtransmission stations. The specific sites were based on projects included in MISO's interconnection queue through 2021, the ITC Hosting Capacity Study[1] and Company selected sites.
- 2,000 MW Storage: This group was assumed to have 1,750 MW connected to the transmission system and 250 MW connected to the subtransmission system within DTE Electric's distribution system based on available injection capacity of the lines and subtransmission stations. All storage, including storage connected to the subtransmission system, was assumed to be paired with up to 50% of the assumed solar installed capacity from above in effort to optimize the interconnections.
- 1,500 MW Dispatchable resource: This resource was assumed to be located in the Monroe area to support the south area transmission and connected at the transmission-level.

DTE Electric also specified to ITC how many MW of replacement projects should be sited in the rest of Zone 7 as explained by Witness Mikulan. The specific siting assumptions for the other parties in Zone 7 were not specified by the Company and were determined by ITC.

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[1] Michigan Hosting Capacity Study: https://www.oasis.oati.com/woa/docs/ITC/ITCdocs/MI_Hosting_Capacity_-_Final.pdf, accessed on October 18, 2022.

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Q23. Do you agree with the approach ITC used in the transmission steady state analysis?

A23. Yes. This was an agreed upon approach based on the timing of the studies that needed to be completed and the MTEP21 model and information available at the time when the analysis process was started. It was important to ensure that a comparison could be made between the transmission results of the ITC scenarios. Transmission analyses of this nature are looking at a snapshot in time to provide indicative results and more detailed studies would be conducted as part of future generation interconnection and transmission planning studies performed within MISO's planning processes.

Q24. How did ITC model Scenario-3?

A24. ITC performed a simplified steady state analysis on ITC Scenario-3. ITC Scenario-1 was determined to be the closest to Scenario 3, therefore modifications to the powerflow models started from ITC Scenario 1.

<u>Section II: Discussion of ITC Study Results</u>

Q25. Did ITC provide a copy of its study results?

A25. Yes. ITC provided DTE Electric with a copy of its study results in the form of a memo. The memo is included in Exhibit A-12.3.

Q26. Can you please summarize the key findings of the steady-state transmission analysis performed by ITC for ITC Scenarios-1, 2a and 2b?

A26. ITC performed the steady state thermal and voltage analysis on the three ITC 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-12.3. The key findings of the steady-state transmission analysis for each ITC scenario are summarized in Table 2 below. The replacement generation and transmission need figures shown by study year are cumulative.

Table 2: Summary of Generation Retirements and Replacements

		Retirement		Replacement Generation (MW)			Transmission Need			
ITC Scenario	Year	Belle River	Monroe	Solar	Storage	CCGT proxy	Line Miles	# Of Station Upgrades	MVAR Need	Transmission Investment ($M)
1	5	Retired	Online	665	0	0	332	2	0	$210
	10	Retired	Retired	6319	1450	1350	950	11	650	$1100
	15	Retired	Retired	6319	1450	1350	969	12	650	$1100
	20	Retired	Retired	7319	2000	1500	1074	12	650	$1300
2a	5	Retired	Online	665	0	0	332	3	0	$210
	10	Retired	Partially Retired	3319	300	700	770	9	0	$800
	15	Retired	Retired	6319	1450	1350	969	12	650	$1100
	20	Retired	Retired	7319	2000	1500	1074	12	650	$1300
2b	5	Converted	Online	0	0	0	0	0	0	$0
	10	Converted	Partially Retired	1619	125	0	534	9	0	$450
	15	Converted	Retired	4619	1000	750	744	12	0	$800
	20	Retired	Retired	7319	2000	1500	1074	12	650	$1300

Q27. Can you define Corrective Action Plan (CAP)?

A27. 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.

Q28. What transmission network upgrades were identified as CAPs to mitigate the thermal violations identified in the steady state analysis?

A28. 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 lines.

Refer to Table-1 and Table-2 in Exhibit A-12.3 for details on the cumulative thermal corrective project types and corrective project line miles identified in the steady state analysis for each ITC scenario.

ITC Scenario-1 (Retire Belle River – 5 years, Retire Monroe – 10 years)

Q29. Can you please summarize the results of the steady-state transmission analysis performed by ITC for ITC Scenario-1?

A29. Yes. ITC Scenario-1 exhibited a high prevalence of thermal violations and the highest number of required CAPs in the 10-year timeframe of the scenarios studied. This is due to the full retirement of both Belle River (both units) and Monroe (all 4 units) and the addition of 6,319 MW of solar, 1,450 MW of storage and a proxy dispatchable resource in the form of the 1,350 MW CCGT with CCS or a SMR. This scenario resulted in the majority of the costs associated with the transmission enhancements, up to $1.1 billion, to address the generation transformation being incurred in the 5- and 10-year time frame. After the 10-year timeframe, minimal requirement of CAPs was identified since the generation transition was minimal.

This scenario also identified reactive power support and voltage regulation need in southeastern Michigan in the 10-year timeframe. The majority of the voltage violations were found in the ITCT footprint. From the voltage analysis it was determined that 650 MVAR of dynamic reactive power support, similar in size to Belle River Units 1 and 2, would be required after the retirement of the Belle River units and full retirement of the Monroe units. This 650 MVAR need is in addition to the 1,500 MW of a new dispatchable CCGT with CCS or a SMR.

<u>ITC Scenario-2a (Retire Belle River – 5 years, Retire two units at Monroe – 10 years, Retire two units at Monroe – 15 years)</u>

Q30. Can you please summarize the results of the steady-state transmission analysis performed by ITC for ITC Scenario-2a?

A30. Yes. ITC Scenario-2a exhibited a moderate prevalence of thermal violations which consequently requires a moderate number of CAPs in the 10-year timeframe. This is due to the full retirement of Belle River, partial 2-unit retirement of Monroe (Units 3 and 4), the addition of 3,319 MW of solar, 300 MW of storage, and 700 MW of dispatchable CCGT with CCS or a SMR. To support the generation transformation occurring in the 5- and 10-year timeframe, ITC estimates up to $800 million in transmission enhancements. In the 15-year timeframe there was a high prevalence of thermal violations requiring additional CAPs, driven by the full retirement of Monroe and incremental addition of 3,000 MW of solar, 1,150 MW of storage and 650 MW of dispatchable CCGT with CCS or a SMR bringing the cumulative additions to 6,319 MW, 1,450 MW, and 1,350 MW respectively. The total estimated cost for the 15-year timeframe is up to $1.1 billion. After the 15-year timeframe, minimal requirement of CAPs was identified as no other generation retirements are occurring.

ITC Scenario-2a also identified a reactive power support and voltage regulation need in Southeast Michigan in the 15-year timeframe. The majority of the voltage violations were found in the ITCT footprint. From the voltage analysis it was determined that 650 MVAR of dynamic reactive power support, similar in size to Belle River Units 1 and 2, would be required after the retirement of the Belle River units and full retirement of the Monroe units.

<u>ITC Scenario-2b (Convert Belle River to natural gas peaking plant – 5 years, Retire two units at Monroe – 10 years, Retire two units at Monroe – 15 years, Retire converted Belle River – 20 years)</u>

Q31. Can you please summarize the results of the steady-state transmission analysis performed by ITC for ITC Scenario-2b?

A31. In ITC Scenario-2b, there was a steady but modest increase to the thermal violations and CAPs throughout the 20-year timeframe. The rate of CAPs required for the transmission system held steady at nearly the same annual rate throughout the 20-year outlook. This was driven by the re-purposing of Belle River and staggered retirement of the Monroe units. The conversion of Belle River resulted in a slower generation transition compared to the earlier retirement of Belle River in Scenarios 2a and 2b providing near-term transmission cost savings. The slow transition results in a deferment of transmission enhancements, which creates savings of $350 million ($800 million versus $450 million) in the 10-year horizon when compared to ITC Scenario-2a. The savings is $650 million

($1,100 million versus $450 million) in the 10-year horizon when compared to ITC Scenario-1. In the five-year horizon the savings are $210 million when compared to ITC Scenario-1 or Scenario-2a ($210 million versus $0). This is due to Belle River remaining a generation asset as opposed to being retired.

ITC Scenario-2b also did not identify a reactive power support and voltage regulation need in southeastern Michigan until the 20-year timeframe. The voltage violations found in the ITCT footprint were not observed until the full retirements of both Monroe and Belle River. The conversion of Belle River to a natural gas peaking resource reduces near-term reliability risk associated with the need for substantial reactive power support (650 MVAR) when both Belle River and Monroe retire.

<u>ITC Scenario-3 (Retire Belle River – 5 years, Retire Monroe – 10 years, no dispatchable CCGT with CCS or a SMR)</u>

Q32. Can you please summarize the results of the transmission analysis performed by ITC for ITC Scenario-3?

A32. Yes, the fourth scenario, referred to as ITC Scenario-3, was screened for steady state impacts with wind, solar, storage, and demand response in place of the proxy low or zero carbon dispatchable resource when Monroe was fully retired in the 10-year time frame (ITC Scenario-1). This was used as a simplified analysis that compared the overall violations between Scenario 1 and Scenario 3 for year 10. The analysis did not include a more comprehensive evaluation of the total cost impacts as was done for Scenarios-1, 2a and 2b over the 20-year horizon, but was used to screen for severity of the changes. In the screening analysis, ITC noted

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some additional and some eliminated thermal violations as compared to the prevalence of thermal violations and the high number of required CAPs in the 10-year timeframe of ITC Scenario-1. In addition, in the screening, ITC found no appreciable difference for voltage violations as compared to ITC Scenario-1 where 650 MVAR of dynamic reactive power support is needed when Belle River and Monroe retire in the 10-year period.

It should be noted that transmission analysis does not necessarily show the operational value of a dispatchable resource in having the flexibility to dispatch up and down to help alleviate constraints in the transmission system. It must also be noted that a stability analysis was not performed for ITC Scenario-3. However, ITC did note in the Addendum of Exhibit-12.3 that it would expect additional dynamic reactive support beyond the mitigation expected for Scenario 1. Additionally, having a new dispatchable resource in a zone may also have benefits for maintaining that zone's CIL as well as the real and reactive capabilities inside a zone as a whole.

Q33. What are New Interconnection Direct Attachment Facility costs?

A33. As described in Exhibit A-12.3, to enable a new generation facility to inject power (real and reactive) into the transmission system with a certain capacity, the following changes to the transmission system are often required:

- Building new interconnection substations
- Upgrades to an existing substation
- Upgrades to the existing transmission network
- Building new transmission facilities

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The cost associated with these changes can be attributed to the new generating facility to be interconnected to the transmission system and the cost is defined as a New Interconnection Direct Attachment Facility Cost or New Interconnection Facility Cost.

Q34. What is the estimated New Interconnection Facility Cost for each of the three ITC scenarios?

A34. The cumulative cost associated with new interconnection attachment facilities for all three ITC scenarios were reported by ITC in Table-3 of Exhibit A-12.3 and are summarized below in Table-3. ITC Scenario 2b defers approximately $93.6 million dollars ($64.8 million versus $158.4 million) of interconnection costs in the 10-year time frame when compared to ITC Scenario 2a.

Table 3: Cumulative Interconnection Attachment Cost High Estimates ($M)

ITC Scenario	5-Year	10-Year	15-Year	20-Year
1	$28.8	$266.4	$266.4	$302.4
2a	$28.8	$158.4	$266.4	$302.4
2b	$0	$64.8	$223.2	$302.4

Q35. Was a transmission system stability analysis performed by ITC as part of the transmission evaluation for ITC Scenarios-1, 2a and 2b?

A35. Yes. The stability analysis was performed on the 20-year case, which was the same in all three ITC scenarios, and had the highest penetration of intermittent resources as well as planned retirements of dispatchable generation in both ITCT and METC systems.

Q36. What were the results of the stability analysis?

A36. ITC did not find major system stability issues with the scenarios provided by DTE Electric, inclusive of the retirements and additions for the rest of Zone 7, that required any transmission upgrades. Due to the number of new generation additions considered in the analysis, a need for adjusting the control system and relay settings was identified but is not necessarily an issue requiring a transmission solution. Therefore, there were no costs associated with transmission stability CAPs in the cumulative cost estimates provided by ITC. However, DTE Electric recognizes that a more in-depth/complex analysis on system stability may yield different results.

Q37. Was a stability analysis completed for ITC Scenario-3?

A37. No. An analysis was not performed for dynamic stability due to the screening nature of the transmission analysis and the ITC resource constraints for completing such a large scale study (i.e., timeframe to allocate engineering resources to build necessary contingencies and perform faults).

Q38. What level of total transmission investment did ITC identify for the transmission network enhancements associated with the DTE Electric's generation transformation plan for ITC Scenarios-1, 2a and 2b?

A38. As mentioned in Exhibit A-12.3 and shown in Table 2 above, the estimated cumulative cost for the transmission enhancement identified by ITC in their evaluation of the ITC Scenarios ranged from $1.0 to $1.3 billion over the 20-year study period. The estimated cumulative cost for the transmission enhancements identified by ITC included the cost of network upgrades for CAPs to mitigate

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steady state thermal and voltage violations, transmission stability issues, and the cost associated with the New Interconnection Attachment Facilities. These cost estimates for the transmission system upgrades were included in the IRP modeling as described by Witness Mikulan.

Q39. Is the required level of investment projected by ITC for the transmission network upgrades appropriate for IRP planning purposes?

A39. Yes. The methodology used by ITC, based on the models and assumptions made, to estimate the $1.0 to $1.3 billion over the 20-year study period appears to be consistent with MISO estimation practices for new interconnection attachment facilities, 12 upgraded stations, 120 different upgraded lines over 1074-line miles for sag remediation, reconductoring, and rebuilding transmission line project types.

Q40. According to ITC, what are the limitations with their study?

A40. The limitations of the ITC study are described in the ITC memo in Exhibit A-12.3. The limitations cited by ITC include, generation expansion only considered within Michigan (Zone 7) and the analysis was limited to single contingency events (i.e., n-1). More mitigation will be needed as the transmission system is studied for multiple contingency events as MISO completes their studies. Lastly, cost estimations were based on today's dollars with no inflation rate and were premised upon numerous assumptions; consequently, the actual costs will vary depending on the actual timing and amount and location of generation additions, retirements, and the corresponding system power flows as well as the cost of land, materials and equipment.

Q41. Given these limitations, what is the significance of ITC's study?

A41. Despite the limitations listed above, ITC's study is informative and a necessary first step toward understanding the transmission impacts and associated costs that may be incurred under several retirement and generation replacement options being considered in this IRP. This study exhibits a good indication of the location of the transmission system vulnerability (i.e., thermal and voltage violations) due to potential changes to the Company's generation fleet, the required transmission CAPs for mitigating the violations and an estimated cost for the transmission CAPs including the cost for the direct attachment facilities for the new interconnection projects considered in the analysis. However, more analysis would be needed before the Company can retire the last 2 units of Monroe and know that the replacement capacity will maintain system reliability. For example, an analysis of multiple points of failure outages may demonstrate the need for additional transmission projects or other solutions such as local generation.

Section III: Consideration of studies on DTE Electric's IRP Process and PCA

Q42. How were the ITC transmission study results considered in DTE Electric's IRP process?

A42. As described by Witnesses Leslie and Mikulan, the IRP process used key insights from the ITC study, along with other studies, to balance reliability with customer affordability. The PCA is similar to ITC Scenario-2b, a conversion of Belle River Power Plant to a natural gas peaking resource and a phased approach to the retirement of the Monroe Power Plant, which had fewer reliability impacts and associated costs in the earlier years of the study compared to the other scenarios.

Q43. What information from the ITC study was used in DTE Electric's IRP process to help ensure reliability?

A43. ITC's study revealed the need for 650 MVAR of reactive resources for the system to be reliable once Belle River and Monroe fully retire. The PCA defers the need for this 650 MVAR of reactive resources through the conversion of Belle River and its operation until the plant retires by 2040. In addition, the upgrades identified by ITC take time to build and may not be able to accommodate the system in time if the fleet transition is accelerated beyond what is proposed in the PCA.

Q44. What is reactive power is and why is it needed for reliability?

A44. Reactive power is essential to move active power through the transmission and distribution system to the customer. Reactive power (VARS) is required to maintain the system voltage to deliver real power (watts) through transmission lines. Reactive power does not travel long distances over transmission lines and must be produced near load. When there is not enough reactive power, voltage drops, and it is not possible to push the power demanded by loads through the lines – with voltage collapse leading to system blackouts. I will describe why reactive power is important to maintain reliability and why transmission cannot be built to accommodate system stability needs in more detail when I explain MISO's Renewable Integration Impact Assessment[2] (RIIA) and MISO Long Range Transmission Planning[3] (LRTP) initiative.

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[2] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, accessed on October 18, 2022.
[3] Mtep21 Report Addendum: Long Range Transmission Planning Tranche 1: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf, accessed on October 18, 2022.

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Q45. What is Renewable Integration Impact Assessment (RIIA)?

A45. RIIA[4] was a compilation of studies performed by MISO that were completed in February 2021 to better understand the impacts of renewable energy growth in MISO over the long-term. This assessment provided concrete examples of renewable integration issues and examined potential solutions to mitigate them. The assessment demonstrated that as renewable energy penetration increases, so does the variety and magnitude of the bulk electric system need and risks and helped inform the sequencing of actions required to manage certain renewable penetration levels.

Q46. What were the key insights of MISO's RIIA that helped inform DTE Electric's IRP?

A46. MISO identified new stability risk and shifting periods of grid stress with increased levels of renewable energy penetration. The following were key insights of MISO's RIIA:

- At 20-30% renewable penetration levels, "issues become visible due to very high subregional instantaneous penetrations… Local generation flexibility needs greatly increase, along with the stress on the high voltage transmission system to allow regional transfer and balancing."[5]
- At 30-40% renewable penetration levels, "The flexibility that traditional generation units provide, if dispatched, will need to increase in magnitude and direction…This period of renewable growth presents a new risk

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[4] Renewable Integration Impact Assessment (misoenergy.org): https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd=, accessed on October 18, 2022.

[5] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, page 14, accessed on October 18, 2022.

related to system stability. Large regional pockets of inverter-based generation need strong reinforcement to maintain system stability, due to these resources' inability to maintain a stable voltage when concentrated in large numbers."[6]

- "As inverter-based resources from intermittent generation displace conventional generators, the grid loses the stability contributions of physically spinning conventional units and the grid's ability to maintain stable operation is adversely impacted."[7]
- "As intermittent resources supply most of the energy, the system becomes more dependent on the stability attributes of the remaining conventional generators."[8]

These insights from MISO -- focusing on reliability to support local generation flexibility and help maintain a stable voltage -- informed DTE Electric's PCA, including the following elements:

- Conversion of Belle River to a natural gas peaking plant within 5 years (2023-2027)
- Staggered Monroe retirement (two units in 10 years (2028-2032) and four units with 15 years (2033-2037)
- Deployment of a new dispatchable resource within 15 years (2033-2037)

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[6] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, page 14, accessed on October 18, 2022.

[7] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, page 3, accessed on October 18, 2022.

[8] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, page 3, accessed on October 18, 2022.

Q47. What is the connection between MISO's RIIA and other on-going work at MISO?

A47. According to MISO, "While grid operators have managed uncertainty for decades, MISO is preparing for an unprecedented pace of change. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges. MISO calls this shared responsibility the Reliability Imperative, which is broken into four categories Market Redefinition, Long Range Transmission Planning (LRTP), Operations of the Future, and Market System Enhancements. RIIA is a key part of understanding the risks ahead."[9]

Q48. Can you describe the LRTP initiative?

A48. As described by MISO, LRTP is a regional transmission planning initiative within MISO that was developed to address the ongoing industry trends related to the transformation of the generation fleet, increased rate of severe weather events, decarbonization policies, and market shifts to electrification. Similar to MISO's Multi-Value Projects that were initiated in 2010, to be included in the LRTP planning process a transmission project must provide improved grid reliability and economic benefits across multiple transmission pricing zones with a primary focus on improving the transfer capability within the entire MISO footprint.

MISO's LRTP process is separated into four different Tranches, with Tranches 1 and 2 addressing transmission issues in the MISO Midwest subregion (which

[9] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf, page 2, accessed on October 18, 2022.

includes Michigan), Tranche 3 addressing transmission issues in the MISO South subregion, and Tranche 4 addressing the need to increase the transfer capability between the MISO Midwest and MISO South subregions. In July 2022, the MISO Board of Directors approved the $10.3 billion Tranche 1 portfolio that includes 18 transmission projects that are spread across the MISO Midwest subregion[10]. DTE Electric will be responsible for paying for approximately 10% of this $10.3 billion based on DTE Electric's load ratio share of the MISO Midwest region.

Q49. When will the LRTP Tranche-1 projects be in service?

A49. MISO currently estimates the projects within the LRTP Tranche 1 portfolio to be in-service between 2028 and 2030.[11]

Q50. How does the conversion of the Belle River Power Plant to a natural gas peaking resource support transmission system reliability?

A50. Consistent with the key findings from MISO's RIIA, the conversion of Belle River Power Plant to a natural gas peaking resource allows it to support both the transmission and distribution system when needed for flexibility and to maintain stable voltage. The rotating mass of the unit provides system inertia to be able to maintain stability through major faults or large disturbances in the system and to provide short circuit strength to the transmission system, which improves system reliability. Also, as found in the ITC study described earlier, the conversion of the

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[10] MISO Board Approves $10.3B in Transmission Projects: https://www.misoenergy.org/about/media-center/miso-board-approves-$10.3-in-transmission-projects/, accessed on October 18, 2022.
[11] Mtep21 Report Addendum: Long Range Transmission Planning Tranche 1: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf, page 2, accessed on October 18, 2022.

Belle River Power Plant defers transmission line upgrades and helps maintain system reliability in the form of a dispatchable resource with dynamic reactive power support deferring the need for 650 MVAR until both Monroe and Belle River retire.

Q51. What is the expected impact of the dispatchable CCGT-proxy included in the PCA (or any dispatchable resource) in the mid-2030's on grid reliability?

A51. Consistent with the key findings from MISO's RIIA and the ITC studies that found the conversion of the Belle River Power Plant helped defer transmission investment and helped maintain reliability through reactive power support, the CCGT-proxy, which will be evaluated in future IRPs, is expected to help with flexibility needs and maintain system reliability by providing voltage stability and avoid transmission investments needed for dynamic reactive support. A dispatchable CCGT with CCS is capable of providing voltage regulation, short circuit strength to the transmission system and the rotating mass of the unit provides system inertia to be able to ride through large disturbances in the system. In summary, adding a new dispatchable resource when the last two units of the Monroe Power Plant retire, is expected to help balance the system while integrating a higher penetration of intermittent resources to reliably support the clean energy transition.

<u>Section IV: Discussion of the Capacity Import Limit (CIL) Analysis</u>

Q52. What is the CIL and Capacity Export Limit (CEL)?

A52. The CIL is the maximum amount of capacity that can be imported into a local resource zone during peak demand operating scenarios without violating thermal, voltage, or generation constraints. The CEL is the maximum amount of capacity that can be exported out of a local resource zone during peak demand operating scenarios without violating thermal, voltage, or generation constraints. The CIL and CEL are calculated for each MISO local resource zone. CIL and CEL transmission rights are not allocated to individual load serving entities under MISO's resource adequacy construct, as discussed further by Witness Burgdorf.

Q53. Can you provide context on the IRP filing requirements and other Commission orders related to the examination of CIL and CEL?

A53. Yes, Sections XII(d) and (e) of the IRP filing requirements adopted by the Commission in U-18461 on December 17, 2017, specify that the utility should include any information provided by the transmission owner indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, as well as potential transmission options that could impact the utility's IRP by increasing import or export capability. In several orders, including the February 2020 interim order in the Company's 2019 IRP and the September 2019 Statewide Energy Assessment, the Commission also expressed interest in examining the expansion of capacity import limits.

Q54. What are the 2022-2023 Planning Year CIL and CEL values for MISO Local Resource Zone ("LRZ") 7?

A54. The CIL and CEL values for MISO LRZ 7 for Planning Year 2022-2023 were 3,749 MW and 2,392 MW respectively. These values were included in the MISO

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Planning Year 2022-2023 Loss of Load Expectation Study Report[12]. In this report, MISO analyzed the import and export capabilities for MISO LRZ 7, which is comprised of the majority of Michigan's Lower Peninsula.

Q55. What was the Michigan Capacity Import/Export Limit Expansion Study[13]?

A55. In 2019, the MPSC requested an informational study to determine transmission expansion options to increase the Capacity Import and Export Limits for MISO's Local Resource Zone 7. The Michigan Capacity Import/Export Limit Expansion Study (MI CIL/CEL Study) considered three Scenarios (a 5-year, 10-year, and 15-year outlook using models from MTEP 2019 and various generation retirement/replacement assumptions). The study concluded in the summer of 2021. DTE Electric actively participated in all workshops and proposed six different alternatives, both transmission and non-transmission alternatives, to increase the CIL as seen in Table 1 in the Michigan Capacity Import/Export Limit Expansion Study[14].

Q56. What was the result of the MI CIL/CEL Study?

A56. The MI CIL/CEL Study resulted in two indicative transmission projects that would expand the CIL to 6,200 MW at a total cost of $91.3 million[15].

[12] Planning Year 2022-2023 Loss of Load Expectation Study Report: https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf, accessed on October 19, 2022.
[13] Michigan Capacity Import/Export Limit Expansion Study: https://cdn.misoenergy.org/20210603%20MTSTF%20Item%2002%20Michigan%20CIL-CEL%20Expansion%20Study%20Report556522.pdf, accessed on October18, 2022.
[14] Michigan Capacity Import/Export Limit Expansion Study: https://cdn.misoenergy.org/20210603%20MTSTF%20Item%2002%20Michigan%20CIL-CEL%20Expansion%20Study%20Report556522.pdf, page 5, accessed on October 18, 2022.
[15] Michigan Capacity Import/Export Limit Expansion Study: https://cdn.misoenergy.org/20210603%20MTSTF%20Item%2002%20Michigan%20CIL-CEL%20Expansion%20Study%20Report556522.pdf, page 2, accessed on October 18, 2022.

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Q57. You mentioned that these transmission projects were indicative. What does an indicative project mean, in the context of the MI CIL/CEL Study?

A57. It means that these projects were not included in the MTEP for approval and construction, but instead were used to inform MISO on the types of projects that could be built to increase the CIL. The MI CIL/CEL Study was said to inform MISO's broader Reliability Imperative initiative (i.e., LRTP) and MISO encouraged Michigan stakeholders to continue to engage with MISO on the development of the LRTP projects in making decisions about how to proceed based upon the MI CIL/CEL Study results[16].

Q58. Was the expected impact of the LRTP Tranche-1 projects analyzed by ITC as part of its transmission analysis conducted for DTE Electric to support the IRP process?

A58. Yes. Given MISO's approval of the LRTP Tranche-1 project portfolio, it was appropriate to consider whether these transmission projects affected the ongoing transmission analysis that ITC was conducting for DTE Electric as part of the IRP process. As seen in Exhibit A-12.3, ITC applied the LRTP Tranche-1 project portfolio to the ITC Scenarios-1, 2a and 2b used in the steady state and stability analysis. According to ITC, the LRTP Tranche-1 project portfolio reduces transmission line loadings and produces corresponding cost reductions in ITC's transmission cost estimate, in the amount of $70 million. Thus, the LTRP Tranche-1 projects could displace the need for some of the transmission upgrades

[16] Michigan Capacity Import/Export Limit Expansion Study: https://cdn.misoenergy.org/20210603%20MTSTF%20Item%2002%20Michigan%20CIL-CEL%20Expansion%20Study%20Report556522.pdf, page 3, accessed on October 18, 2022.

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associated with the PCA. This cost reduction does not, however, factor in the cost of the LRTP Tranche-1 portfolio that would be assigned to DTE Electric.

Q59. What was the impact of the LRTP Tranche-1 project portfolio on the LRZ 7 CIL as determined in the MISO LRTP analysis?

A59. According to the MISO LRTP Tranche 1 Portfolio Report presented during the Planning Advisory Committee (PAC) meeting held on May 27, 2022 (Chapter-7), the LRTP Tranche-1 projects are expected to increase the LRZ 7 CIL by 1,292 MW which includes ITCT and METC systems (i.e., Lower Michigan). The report can be found in the link below[17].

Q60. How does the LRTP Tranche-1 project portfolio for LRZ 7 compare to the indicative projects proposed under the Michigan Capacity Import/Export Limit Expansion Study?

A60. As seen in Exhibit A-12.5 on March 11, 2022, MISO shared that the LRTP Tranche-1 projects in the 20 year-out model outperform the upgrades identified in the original MI CIL/CEL Study.

Q61. Did DTE Electric request ITC to perform a CIL analysis to evaluate the impact of the PCA on LRZ 7 CIL?

A61. Yes, this request is described in the statement of work in Exhibit A-12.2 and the results of the analysis can be found in Exhibit A-12.4. DTE Electric's request for

[17] MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf, page 57, accessed on October 18, 2022.

the CIL analysis on the PCA was made in response to the IRP filing requirements discussed above.

Q62. Can you describe the results of the CIL analysis performed by ITC?

A62. Yes. As described in Exhibit A-12.4 and shown in Table 4, ITC's analysis indicates that ITC does not expect the generation changes in the DTE 2022 IRP PCA, to result in any material change in LRZ 7's current CIL value or future CIL values after LRTP Tranche 1 projects are in service, which is expected by the end of 2030.

Table 4: Calculated CIL Values

Key Study Year	Preliminary PCA (Without LRTP)	Preliminary PCA (With LRTP Tranche 1 Projects 2030)
2028	4500 MW	6500 MW (after 2030)
2035	4200 MW	6300 MW

In addition, ITC noted that the calculation of the CIL is based in large part on transmission system flows that can be impacted both by generation output and transmission topology (e.g., impedance). According to ITC, "Changes to future generation locations could materially increase or decrease the CIL, even if the transmission topology has no changes. Intermittent resources in a zone, can only be curtailed which could increase the CIL, but in-turn might limit the real and reactive capabilities inside a zone. Dispatchable (e.g., thermal) resources in a zone have benefits for maintaining a zone's CIL since they can be dispatched up or down to avoid transmission constraints."

Q63. Does the Company expect any current MTEP transmission projects to have a material impact on the CIL prior to MISO's LRTP projects?

A63. Not at this time. MISO's LRTP projects are the focus to try to improve CIL in Michigan. CIL studies are highly sensitive to assumptions and limiting elements can vary greatly from year to year; therefore, the projects to improve CIL are being addressed through MISO's LRTP.

Q64. Why does reactive power need to be produced locally and how does it enable full use of the estimated CIL values?

A64. As described previously, reactive power does not travel long distances over transmission lines and must be produced near where it is needed. When there is not enough reactive power, voltage drops, and it is not possible to push the power demanded by loads through the lines. Reactive power can also occupy the capacity of the CIL for the import of real power as needed for the economic dispatch. Moreover, utilizing the transmission lines close to their capacity limits, increases the need for those lines to absorb reactive power to maintain the voltage at an acceptable level, avoiding a voltage collapse (blackout). The inclusion of a dispatchable resource can help provide a local source of reactive power to enable the full use of the CIL. In addition, as noted by ITC's CIL analysis, "the calculation of the CIL is based in large part on transmission system flows that can be impacted both by generation output and transmission topology (e.g., impedance). Changes to future generation locations could materially increase or decrease the CIL, even if the transmission topology has no changes. Intermittent resources in a zone, can only be curtailed which could increase the CIL, but in-turn might limit the real and reactive capabilities inside a zone. Dispatchable (e.g., thermal) resources in a zone have benefits for maintaining a zone's CIL since they can be dispatched up or down to avoid transmission constraints."

Q65. Did the PCA account for the import/export capabilities of the transmission system in its development to displace, defer, or optimize the amount, type, and location of additional generation?

A65. Yes. The import/export capabilities into LRZ 7 is an important component of maintaining 24/7 reliability as DTE Electric integrates more zero carbon intermittent resources into the system. DTE Electric will rely on this import/export capability to optimize the 24/7 energy delivery from MISO for the benefit of its customers. As discussed by Witness Burgdorf, since most of MISO are fully regulated utilities planning for capacity to meet only their own utility need, to ensure reliability DTE Electric's PCA also includes enough dedicated capacity to meet its customer's needs.

<u>Section V: Other Transmission System Studies</u>

<u>Peaker Sensitivity</u>

Q66. Did the Company ask ITC to study a peaker sensitivity as part of its steady state transmission study?

A66. Yes. The Commission's order in the Company's 2019 IRP Case No, U-20417 identified the need for further analysis of peaking generation. To prepare for the

2022 IRP, the Company identified a group of peakers for evaluation and potential retirement consideration. ITC conducted the sensitivities on Scenario 2a, the 5- and 10-year studies. ITC performed a sensitivity where the peakers were turned on. For further discussion of the peaker analysis and the factors that are considered when retiring a generation asset, including grid reliability, refer to Witness Morren's testimony.

Q67. What were the results of the ITC peaker sensitivity?

A67. As noted in Exhibit A-12.3, ITC determined that there would be no material impact to the expected cost estimates or CAPs. The benefits of peakers in redispatch would be most noticeable when considering N-1-1 contingencies for the system and allowing additional flexibility in operations and planning.

Q68. Are there MISO studies relevant to this IRP process?

A68. Yes. As part of the peaker analysis it was noted that three of the peaker sites considered for potential retirement are connected to the transmission system. The peaker sensitivity described above indicated that there were no steady state issues identified. To further understand if there are transmission impacts from specific peaker sites DTE Electric engaged MISO to evaluate whether ~38 MWs of peaker units could retire at the Fermi, River Rouge, and St. Clair sites without being required to stay online as a MISO system support resource (SSR) per section 38.2.7b. of the MISO tariff. The study is on-going at the time of this filing.

Q69. Does this complete your direct 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

GRACE N. MUSONERA

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF GRACE N. MUSONERA

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

A1. My name Grace N. Musonera (she/her/hers). 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.

Q3. What is your educational background?

A3. I received a Bachelor of Science in Electrical Engineering from Texas Tech University, Lubbock, Texas, and a Masters of Business Administration from Wayne State University, Detroit, Michigan.

Q4. What is your work experience?

A4. I began my career at DTE Electric in 2010 as a sub-transmission planning engineer in Operation and Planning Engineering responsible for planning and maintaining the reliability of the sub-transmission system in the southeast region. During my years in Operation and Planning Engineering, I represented DTE Electric as a transmission planning oversight engineer conducting analytical studies to consider power system thermal, voltage, and reactive behavior for transmission system expansion, interconnection of new generation, and load to the transmission system.

In 2016, I took a position with the Federal Regulatory Affairs Department of the Regulatory Affairs Organization. In this role I was responsible for managing regulatory filings and provided witness testimony in the Power Supply Cost

Recovery (PSCR) proceedings. In 2018, I joined the Distribution Operations (DO) Project Management team where I managed the first conversion project in the City of Detroit Infrastructure (CODI) strategy plan for the downtown Detroit electrical system. I was promoted to a Supervising Engineer in 2019 and joined the Central Distribution Engineering team responsible for developing and executing long term plans for the distribution system.

Q5. What is your current position and what are your current responsibilities?

A5. Currently, I am a Manager in the Distribution Operations Long Term Strategy team. In this role, I lead the development of the Distribution Grid Plan as well as other varied long term grid planning and regulatory efforts.

Q6. Were you involved in regulatory filings with the Michigan Public Service Commission in the past?

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

Case No.	Description
U-17920-R	DTE Electric's 2016 Reconciliation of its Power Supply Cost – Recovery (PSCR) Plan
U-20069	DTE Electric's 2017 Reconciliation of its Power Supply Cost Recovery (PSCR) Plan

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to

- Explain how the 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);
- Describe system-wide avoided Transmission and Distribution (T&D) capacity values for the Company's Energy Waste Reduction (EWR) program to support the IRP modeling;
- Describe the distribution cost assumptions associated with the interconnection of new generation used by the IRP modeling team; and
- Describe the steps Distribution Operations (DO) is undergoing related to the peaker generation study

Q8. How is your testimony organized?

A8. My testimony consists of four parts:

Part I	Planning Coordination
Part II	CVR/VVO Program
Part III	Other Distribution Operations Assumptions for IRP Modeling
Part IV	Distribution Operations Peaker Analysis

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am supporting 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
A-13.2	System-Wide Avoided T&D Capacity Value

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

Part I: PLANNING COORDINATION

Q11. Witness Leslie discusses the increased coordination between resource and distribution planning. How has the MPSC addressed this topic?

A11. The coordination of planning between IRPs and distribution system planning was addressed by the Commission as part of its order establishing the MI Power Grid initiative (see October 17, 2019, order in Case No. U-20645).[1] As part of this 2019 order, the Commission identified and emphasized the need to align resource, transmission and distribution planning around "optimizing grid investment and performance". Specifically, the Commission commented that:

> *"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,*

[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).

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as detailed in the 2019 Statewide Energy Assessment." (p. 8, Case No. U-20645, Oct. 17, 2019 order)

Q12. What challenges were identified by the Commission related to the integration of the IRPs and distribution system 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. Did the Commission provide direction to address these planning challenges in its September 24, 2021 order in U-20633 et al.?

A13. Yes. The Commission adopted recommendations from Staff's May 27, 2021, report in its September 24, 2021, order in U-20633. These recommendations provided that: 1) utilities increase consistency throughout the planning processes and coordination of timing between processes to ensure the information flow from one process to another is consistent and accurate and to create a link between various inputs, outputs and resulting decisions; 2) increased communication and transparency in the resource, transmission, and distribution planning processes both within the utility organization and with stakeholders; and 3) utilities engage in planning as an iterative process to provide a clear picture of how resource,

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transmission, and distribution planning process can impact and support one another. (see p. 26)

Q14. Can you briefly discuss how the Company has implemented these recommendations related to the integration of distribution and generation planning?

A14. Yes. The Company submitted its Distribution Grid Plan (DGP)[2] to the Commission in September 2021, building from foundation established in the first distribution plan filed in 2018. The 2021 DGP is based on shared planning objectives for generation and distribution planning and lays out the investments necessary to enhance reliability, modernize the electric distribution infrastructure, and integrate Electric Vehicles (EVs) and other Distributed Energy Resources (DERs) such as solar and battery storage. The Company has numerous ongoing collaborative efforts related to distribution and generation planning. These efforts include:

- 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 Witnesses Leslie and Mikulan
- Advancement in load forecasting methodologies and tools to support both distribution planning and IRP planning processes, as discussed by Witness Leuker

[2] The Company's Distribution Grid Plan could be found on the MPSC site 068t000000Uc0pkAAB (force.com), https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000Uc0pkAAB . Accessed October 21, 2022

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- 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 2021 DGP 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
  - estimated distribution costs associated with new generation resources
- Coordination among multiple business units including Distribution Operation in the peaking generation study to better understand distribution system impacts as discussed further by Witness Morren and in my direct testimony
- Improved information sharing with external stakeholders related to distribution planning topics including participation by Distribution Operations team in IRP public open houses as discussed by Witness Leslie

This IRP builds on the advancements in distribution planning and incorporates distribution planning assumptions and considerations to support a more holistic planning approach. Continued coordination between the Company's IRP and distribution planning teams and processes will be important to understand and account for the impacts of DER and electrification on both the bulk power and distribution systems.

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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. How are DERs driving the need for increased coordination between distribution and generation planning?

A16. The expectation that DER adoption will continue to increase and impact both distribution system planning as well as generation planning is driving the need for increased coordination between the planning teams.

Specifically, with an increased adoption of DER, load forecasting will need to advance and become more robust to account for the forecasted impacts of DERs and EVs on capacity and energy needs at the aggregate system level in IRPs as well as the distribution, or circuit-level, for distribution planning. Moreover, increased levels of DERs and two-way power flows will likely alter load patterns and system conditions. Therefore, it will be important to have increased visibility into system conditions to inform operations and planning, as well as enhanced communications, sensing, and control technologies to mitigate grid impacts and optimize integration of DERs. The 2021 DGP established a roadmap to modernize the grid through base

[3] August 20, 2020, order in Distribution Investment and Maintenance plan Case No. U-20147, page 11

infrastructure investments and technology applications to better integrate DERs and maintain safe, reliable operations.

Q17. Can you discuss how the Company is improving forecasting methods and tools to prepare for increased DER adoption rates?

A17. The DO team is working with the Corporate Energy Forecasting (CEF) team to develop a forecasting solution that accounts for the potential distribution grid benefits and 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 advancements in forecasting are consistent with the Commission's May 27, 2021, Order in Case No. U-20633, to align planning processes, data, assumptions, and methodologies for a more consistent, integrated and scenario-based approach. Witness Leuker provides additional details as well as the status of the new forecasting solution under development in his testimony.

Q18. Will the Company continue to coordinate efforts between distribution and resource planning with the increased adoption of DERs?

A18. Yes, the Company is already taking steps to increase collaboration between generation and distribution planning to be prepared for changing grid conditions with increased electrification and DERs. As DER adoption grows, continued coordination between the Company's IRP and distribution planning teams and processes will be important to understand and account for the impacts on both the bulk power and distribution systems.

<u>Part II: CVR/VVO</u>

Q19. What is Volt-Var Optimization and Conservative Voltage Reduction?

A19. Volt Var Optimization (VVO) manages system-wide reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing circuit level voltage, optimizing operating parameters and/or optimizing power factors, etc.

Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to maintain customer voltage down to the circuit level in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand and energy consumption. CVR/VVO provides both a benefit to the distribution system as well as a generation alternative through reduced demand and energy consumption.

CVR is achieved by utilizing various electrical equipment including transformer load tap changers (LTC), overhead line regulators, and capacitor banks. In addition, supervisory control and data acquisition (SCADA) monitoring devices and line sensors are used to ensure customer voltage levels are maintained in allowable voltage ranges; advanced telecommunication and optimization tools can also be used to achieve optimal savings in the system.

Q20. Why is the Company evaluating CVR/VVO?

A20. The Company has been evaluating CVR/VVO as an option to reduce peak demand and energy consumption as a generation alternative as part of the Company's implementation of the Commission-approved Integrated Resource Plan in Case U-20471. The Company is continuing to implement and evaluate CVR/VVO as an offset to peak generation, and because of the potential benefits to the distribution grid. In addition to the direct benefits as a generation alternative, CVR/VVO supports the installation of increased monitoring and control in support of the larger distribution grid plan for a more advanced distribution system.

Q21. Can you describe the CVR/VVO program the Company is pursuing?

A21. Prior to the CVR/VVO program, a pilot was pre-approved in the Company's Integrated Resource Plan Case No. U-20471. The pilot implemented a series of upgrades on selected circuits to allow voltage reduction at substation transformers using a time-based schedule. In addition, the pilot included measurement and analysis of the expected benefits. The technology upgrades needed to implement CVR/VVO on selected circuits include two major components.

The first technology enhancement is to enable real time remote monitoring and control capability at substations and on circuits. The technology upgrades could take the form of:

- Installing Remote Terminal Units (RTU) and SCADA at substations to enable remote voltage and current monitoring and to enable remote control of transformer load tap changers when needed.
- Installing advanced voltage sensors on circuits to enable remote monitoring of circuit primary voltage.

The second technology enhancement is to install or upgrade line capacitor banks to improve voltage conditions. The technology upgrades could take the form of:

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- Installing remote controllable capacitor banks in new locations to improve circuit voltage profile during peak hours.
- Upgrading capacitor banks at existing locations with remote control to improve circuit voltage profile during peak hours.

The exact technology installed at substations and on circuits could vary depending on detailed engineering and technology analysis prior to CVR/VVO implementation on individual circuits. As the Company scales up CVR/VVO beyond the pilot, the goal is to verify the CVR/VVO implementation on a portfolio of circuits to better understand program costs and benefits as well as any field execution constraints.

Q22. Did DTE Electric reflect the approved CVR/VVO pilot in the starting point for the 2022 IRP modeling?

A22. Yes, in discussions with the IRP team, the demand savings associated with the CVR/VVO pilot approved in the 2019 IRP were reflected in the modeling starting point for the 2022 IRP. As shown in Exhibit A-13, this includes approximately 28.7 MW of cumulative CVR/VVO through 2025.

Q23. What CVR/VVO plans does the Company have to scale up this technology on its distribution system?

A23. Based on the promising results of the pilot, the Company intends to continue investments in CVR/VVO in 2022 and beyond as a program. The Company has continued to engage with industry experts and peer utilities that have implemented CVR/VVO around approaches to achieve energy and demand savings for

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customers. Specifically, the Company plans to move beyond the pilot and to invest in a more advanced approach to CVR/VVO, where set points for substation transformer LTCs, capacitor banks and regulators are coordinated and adjusted dynamically to optimize the voltage levels on a real-time basis to maximize demand and energy savings. Substations for CVR/VVO implementation are prioritized based on their energy reduction potential and synchronized with the substations selected for the Company's substation automation program. This advanced approach to CVR/VVO would leverage the Company's Advanced Distribution Management System (ADMS) to manage the real-time control of the equipment involved. This new CVR/VVO approach is expected to produce higher demand and energy savings than the pilot and provide flexibility in adjusting voltages to better accommodate distributed energy resources. For instance, with the pilot approach of CVR/VVO, if a voltage reduction on substation transformer led to low voltage conditions during any time period, the substation transformer would not be selected for CVR/VVO implementation, thus limiting its applicability. In contrast, using the updated approach, the substation transformer could still be selected for the advanced approach of CVR/VVO because the substation transformer voltages will be adjusted to automatically maximize voltage reduction and avoid low voltage conditions. ADMS control of CVR/VVO through the ADMS Volt-Var control (VVC) module is expected to be implemented in 2024.

Q24. What is the investment plan and the scope of work for CVR/VVO program as part of the PCA?

A24. The Company continues to implement the CVR/VVO investments approved in the 2019 IRP and reflected in the starting point of the 2022 IRP as discussed above.

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The PCA includes approximately 7.5 MW per year from 2026 through 2030 as shown in my Exhibit A-13 for a total of 37.5 MW through that period. The program is maintained at a demand savings level of approximately 66.2 MW through the end of the study period. To enable implementation of advanced CVR/VVO and maximize energy and demand savings for customers, the CVR/VVO implementation for selected substations will include:

- Upgrade substation transformer LTC with remote control capability;
- Install remote controls for existing overhead capacitor banks or install new smart capacitor banks at targeted locations on the circuits;
- Install remote controls for line regulators;
- Install voltage sensors at strategic locations to monitor primary voltage levels; and
- Implement the VVC module from the ADMS to allow real-time voltage control and optimization.

Substations for CVR/VVO implementation are prioritized based on their energy reduction potential and synchronized with the substations selected for the substation automation program.

Q25. When you factor in the existing CVR/VVO in the modeling starting point and the incremental CVR/VVO that are part of the PCA in this 2022 IRP, what are the total savings levels and associated costs?

A25. As shown in Exhibit A-13, the CVR/VVO program is expected to generate 66 MW of peak demand reduction and 103 GWh of energy reduction by 2030. Exhibit A-13 also lists annual incremental peak demand reduction, cumulative peak demand reduction, annual incremental energy reduction, and cumulative energy reduction from the program, based on mid points of the saving estimates.

As shown in Exhibit A-13.1, the program is expected to cost $68 million of capital through 2025, with a projected cost estimate of $20 million in 2025 continuing at that level through 2030, adjusted for inflation.

Q26. Is the Company requesting pre-approval of costs for the incremental CVR/VVO investments included in the PCA?

A26. No, the Company expects to continue to address cost recovery requests through the rate case process, consistent with its approach in Case No. U-20836.

Part III OTHER DISTRIBUTION OPERATIONS ASSUMPTIONS FOR IRP MODELING

Q27. Are you supporting other assumptions used in the IRP modeling?

A27. Yes. I am sponsoring Exhibits A-13.2, that detail assumptions shared with the IRP modeling team to reflect the estimated deferred transmission and distribution costs associated with the EWR program. These estimates were developed by DO. The estimates for deferred T&D costs were also shared with Witness Bilyeu, who discusses the Company's EWR inputs in the PCA and other assumptions related to the program costs and benefits.

In addition, a study was performed in 2021 by Sargent and Lundy under DO direction that quantifies the potential distribution and subtransmission grid upgrade costs that would result from Belle River and Monroe Power Plant retirement and

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resource replacement scenarios. See Table 1 for the estimated distribution costs that were provided to the IRP team for use in their economic modeling.

Table 1. System upgrade estimates

Belle River Power Plant	Monroe Power Plant	Distribution/Subtransmission Cost Estimate
Off	2 units off	\$60 - \$70M
On	2 units off	\$60 - \$70M
On	4 units off	\$90 - \$110M

It should be noted that the retirement of any generating units would require a study by MISO to determine if the retirement has transmission impacts that need to be addressed prior to unit retirement

Part IV: DISTRIBUTION OPERATIONS PEAKER ANALYSIS

Q28. Can you describe the role peaking generation provides to support the distribution system?

A28. Peaker generation resources have the ability to go from offline to full load within minutes to meet emergent system demand. The generation peaker fleet plays a key role in supporting the reliability of the distribution grid. Peaker units have the ability to provide grid edge local capacity and voltage support during planned and unplanned outages on the distribution system. The peaker generation units are utilized during planned outages to provide local system support in the event of any system issues or unexpected power flows. This support is critical to allow electrical system supervisors to confidently schedule the necessary shutdowns to perform routine maintenance and replacements on equipment while minimizing customer interruptions, as well as execute necessary system upgrades to meet future needs of our customers. In some circumstances, peaker generation units also provide an ability to restore customers' service during a storm or other multiple unplanned outage events before the grid can be restored to normal operating conditions. Without peaker support, the Company's ability to serve pockets of customers during adverse system conditions may be negatively impacted until distribution system mitigations can be developed and constructed.

Q29. Could you provide an example of how peaking generation is used during unplanned and planned outages on the distribution system?

A29. During events such as a storm, system equipment failure, and performing routine maintenance on the system, peakers are utilized to mitigate equipment overloads and low voltage issues on the distribution system. During routine maintenance on a transmission (120kV) line or subtransmission (40kV) line, peakers can be utilized in the event of next contingency loss of another piece of 120kV or 40kV equipment. In the case of next contingency, peakers could be put in service and used as necessary to support the system and prevent cascading outages on the system.

Q30. Witness Morren discusses the Company's peaker analysis to evaluate certain peaking units. Can you describe DO's role in this peaking generation analysis?

A30. After the Energy Supply team selected the peakers for analysis, DO reviewed the list and identified those with known distribution system impacts. DTE Electric maintains operating practices which document the system load conditions and equipment shutdowns that trigger the use of localized peaking generators. During these known conditions, local generation resources such as peakers that are able to supply reactive power, are utilized to temporarily help support distribution system demands, and minimize potential overloads and voltage drops.

If not mitigated, the retirement of peaking units with known distribution system impacts may produce reliability issues and low voltage violations during both planned and unplanned outages since these units would be unavailable to support the distribution and transmission systems. To accommodate the loss of peaker benefits, distribution grid mitigation projects will be required to minimize the risk of distribution system failure during adverse system conditions. In cases where an impact to the distribution system was identified, DO estimated preliminary mitigation costs associated with upgrading the distribution system as well as potential transmission costs. These costs were provided to Witness Cejas Goyanes for his analysis on peaker retirements.

Q31. How were the estimated mitigation costs determined?

A31. A potential distribution solution was identified based on a review of the distribution system impact studies. Once a potential solution was identified the associated costs were estimated. In addition, the DO team estimated potential transmission costs to support a retirement. The costs are shown in Table 2.

Table 2. Peaker distribution and transmission estimates

Peaker Units	Connection (kV)	DTE Electric Cost Estimate (M)	Transmission Cost Estimate (M)
FERMI 11-3 & 11-4	120	$0	$0
ST. CLAIR DG 12	120	$0	$0
RIVER ROUGE DG 11	120	$0	$0
SLOCUM DG 11 (Battery Pilot)	24	$40	$0
OLIVER	40	$3.7	$0
WILMOT DG 11	40	$3.7	$0
HANCOCK 11	40	$11	$0

NORTHEAST 11	24	$10	$0
HANCOCK 12	120	$0	$8
NORTHEAST 12	120	$0	$8 total (for NE 12 and 13)
NORTHEAST 13	120	$0	
COLFAX DG 11	40	$6.5	$40
PLACID DG 12	40	$7	$3
PUTNAM DG 11	40	$14	$0
SUPERIOR	40	$24	$0

Q32. How did DO determine that the identified peakers may cause an impact to the distribution system if the peaker was retired?

A32. DO set generation and loading parameters to internally model the electrical system and identify known contingency scenarios that would likely have an impact on the reliability and operability of the distribution system with the retirement of certain peakers. The DO analysis indicates that the retirement of the units with known distribution system impacts is expected to produce reliability issues, especially within the local area where these units have been designated as customer outage mitigation measures. A review of the minimum distribution and transmission system upgrade scope to satisfy these distribution system needs without the peaker units has provided direction on which units require additional study. More analysis is needed given the complexity of how peakers support the distribution system.

Q33. What are the next steps in the peaker analysis study?

A33. Distribution Operations will work with a third-party service provider to perform a more detailed analysis to identify mitigation projects to address any identified distribution system issues created by a peaking generation retirement. The DO team will work with the Energy Supply team to create a prioritized list of peakers for more in-depth analysis. If projects are identified these will likely be considered in the distribution planning process (i.e., conversions, subtransmission upgrades) and future DGPs. The results of the third-party analysis will be shared with the Energy Supply team to determine potential future actions.

Q34. Does this complete your direct testimony?

A34. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

RYAN C. PRATT

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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, Planning and Procurement, within the Fuel Supply department.

Q2. What is your business address and on whose behalf are you testifying?

A2. My business address is One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of DTE Electric Company (the "Company" or "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. Please summarize 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.

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In 2015, I transferred to the Fuel Supply department of DTE Electric as Supervisor, Planning and Procurement and have since been promoted to the role of Manager, Procurement.

Q5. What are your duties and responsibilities in your current position?

A5. My current responsibilities include 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 am also responsible for planning the delivery of those fuels to the Company's power plants and forecasting fuel costs and transactions.

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-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

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U-20826 DTE Electric’s 2021 PSCR Plan

U-20827 DTE Electric’s 2021 PSCR Reconciliation

U-21050 DTE Electric’s 2022 PSCR Plan

U-21259 DTE Electric’s 2023 PSCR Plan

I have also provided support to the DTE Electric fuel witness in the following MPSC cases:

U-18419 DTE Electric’s 2017 Certificate of Necessity Case

U-20069 DTE Electric’s 2017 PSCR Reconciliation

U-20162 DTE Electric’s 2018 Main Electric Rate Case

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 fuel supply arrangements and costs associated with the Company's existing and planned generating facilities;
- Describe and support the fossil fuel price forecasts used in the Company's Integrated Resource Plan (IRP) process; and
- Describe the expected fuel costs associated with potential proposed or future supply resources.

Q8. Did you provide inputs to the group responsible for conducting the integrated resource planning 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 fossil 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-14	Henry Hub Price Forecast Accuracy – EIA Annual Energy Outlook 2009 - 2020
A-14.1	Henry Hub Price Forecast Accuracy – Market Futures 2009 - 2020
A-14.2	Henry Hub Price Forecast Accuracy – Siemens vs EIA AEO 2014- 2020

Q10. Were these exhibits prepared by you or under your direction?

A10. Yes, they were.

PART 1: FOSSIL FUEL SUPPLY TO DTE ELECTRIC'S EXISTING GENERATING FACILITIES

Q11. Would you please describe the Company's existing fossil-fueled generating facilities?

A11. As described by Company Witness Morren, DTE Electric has a number of existing generating facilities powered by fossil fuels. Currently, coal generators are the largest portion of the Company's capacity mix and consist of generators at the Monroe and Belle River Power Plants. DTE Electric also has gas-fired generating capability at the Blue Water Energy Center (BWEC), Greenwood, Renaissance, Dean, Belle River Peakers, Delray, Dearborn, Hancock, Northeast, and St. Clair sites. Furthermore, the Company has oil-fired generating capability at its Monroe and Belle River Power Plants along with a number of oil-fueled peaking units.

Q12. How does the Company procure fuel supply for its existing natural gas-fired generating facilities?

A12. 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 (LDC). A brief summary of how natural gas is supplied to each of the Company's gas-fired generators is provided below.

BWEC

DTE Electric purchases gas year-round with a combination of short-term and long-term purchases. In order to reduce exposure to spot prices and reduce price volatility for our customers, approximately two-thirds of BWEC's supply will be purchased on a forward basis at fixed prices. The Company has firm transportation agreements with Vector and Enbridge for access to the Dawn hub and with DTE Gas and NEXUS for access to the Utica Marcellus region, providing redundancy in transportation service to diversify locations of gas supply. DTE Electric has firm storage and balancing agreements with Enbridge and Washington 10 which include approximately 7.5 billion cubic feet (Bcf) of storage capacity. These contracts allow for multiple ways to service BWEC reliably while minimizing costs to its PSCR customers.

Greenwood 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 SEMCO lateral. 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 their system to the plant. The Company's agreement with DTE Gas includes approximately 1.1 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

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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 firm storage capacity.

Belle River Peakers

DTE Electric purchases gas from a third-party marketer 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 peakers.

Delray and Dearborn

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 0.35 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.

Q13. What types of coal are consumed at the Company's coal-fueled power plants?

A13. The Company's coal-fueled power plants consume a combination of Low Sulfur Western (LSW) and High Sulfur Eastern (HSE) coal. LSW accounted for approximately 85% of the Company's coal consumption in 2021, 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 has the ability to blend HSE and LSW coal in an effort to utilize the higher heat content of HSE coal and maximize generation production during high market opportunities. In addition to coal, petroleum coke (petcoke), a byproduct of the petroleum refinement process, is an economic fuel which provides higher heat content when compared to coal. Petcoke is consumed only at the Company's Monroe Power Plant due to its emissions control equipment.

Q14. How does the Company procure fuel supply for its existing coal-fired generating facilities?

A14. A brief summary of how coal is supplied to each of the Company’s coal-fired generators is provided below.

<u>Belle River Power Plant</u>

In order to ensure 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. Belle River Power Plant exclusively consumes LSW from Montana, which is transported via rail to DTE Electric’s subsidiary, Midwest Energy Resources Co. (MERC), in Superior, Wisconsin, which provides transshipment services to DTE Electric and other third-party customers. The coal is then held in inventory and subsequently loaded into lake freighters for transportation to the power plant.

Monroe Power Plant

In order to ensure 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 of these fuels can be delivered via rail and vessel, although petcoke is delivered primarily via truck. LSW and petcoke vessel shipments utilize MERC as a transshipment facility while HSE vessel shipments utilize various Lake Erie docks for transshipment.

Q15. How does the Company procure fuel supply for its existing oil-fired generating facilities?

A15. The Company uses diesel 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.

PART 2: FOSSIL FUEL PRICE FORECASTS USED IN THE IRP PROCESS

Q16. What fossil fuel price forecasts were used in the IRP Process?

Line No.

A16. The fossil fuel price forecasts used in the IRP Process are shown in Section 13 of the IRP Report. The fossil fuel price forecasts for natural gas, coal, and oil are described below.

Natural Gas

Q17. How was the natural gas price forecast used in the IRP process developed?

A17. 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.

Q18. How does the Company forecast gas supply costs?

A18. 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 2022, these prices were determined by using the Chicago Mercantile Exchange (CME) Group/New York Mercantile Exchange (NYMEX) near-term futures prices. Starting in 2023 through 2025, a transition period starts which was based on a combination of near-term futures prices and the long-term gas price forecasts from Siemens Power Technologies International (Siemens). The long-term Siemens forecast is used exclusively starting in 2026. This forecast methodology is consistent with the process used by the Company in developing its forecasts for its PSCR Plan filings and the 2019 IRP.

Q19. How was the long-term gas price forecast developed?

A19. The Company acquired a long-term gas price forecast from Siemens. Witness Manning describes the Siemens gas price forecast in more detail in her testimony.

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Q20. 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)?

A20. DTE Electric's natural gas price forecast methodology has been more accurate than the EIA AEO price forecasts. The EIA AEO forecasts have historically been higher than the actual price of natural gas. Exhibit A-14 shows the EIA AEO nominal Henry Hub Natural Gas Spot Price projections published from 2009 – 2020 in lines 4-15. Line 1 shows the actual Henry Hub spot prices from 2010 – 2021. Lines 18-29 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 – 2021 were higher than the actual price in 75 out of 78 predictions. These predictions averaged 92% higher than actual, with the percent error being as much as 373%.

Q21. How has the Company's gas price forecast methodology performed over the same period?

A21. Exhibit A-14.1 shows the historical accuracy of the market futures, which the Company used for the first two years of the gas price forecast, before transitioning into the long-term Siemens forecast. While the market futures have been higher than actual prices in recent history, they have been more accurate than the EIA AEO projections. Exhibit A-14.1 shows the percent error of the market futures compared to the actual prices. The market futures averaged 69% higher than actuals while the EIA AEO has been 92% higher. In addition, the market futures were a better predictor of actual spot prices than the EIA AEO in 67 of 78 instances.

The Company has used Siemens for the long-term natural gas price forecasts since 2014. Siemens' 2014 through 2020 forecast accuracy can be compared against the EIA AEO over the same time period. Exhibit A-14.2 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 59% higher for the same period.

Q22. How were gas transportation and delivery costs determined?

A22. Transportation costs were added to the supply costs to represent the costs associated with transporting the gas from the relevant hub to the power plant. Depending on the plant and location, transportation costs may have been based on existing agreements or general service tariff rates.

<u>Coal</u>

Q23. How were the delivered coal price forecasts used in the IRP process developed?

A23. Coal commodity costs were added to transportation rates, including railcar costs, to determine the delivered cost of coal by route to each generation facility.

Q24. How does the Company forecast coal commodity prices?

A24. For 2023 and 2024, 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 2026 and 2027, the forecasted coal cost was derived by applying an inflation index factor to the 2025 forward market coal prices. Beyond 2027, the Company utilizes the Siemens forecast escalation applied to the forward market coal prices. Witness Manning describes the Siemens forecast in more detail.

Q25. How does the Company forecast coal transportation rates for the remaining months of the current year and the subsequent five years?

A25. 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.

Q26. How was the petcoke price forecast developed?

A26. Petcoke prices utilize forward-market prices through 2026. Then, the Siemens deflator series was applied each year on the forwards price starting in 2027.

<u>Oil</u>

Q27. How are delivered oil price forecasts developed for existing generating plants?

A27. 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. For 2022, fuel oil supply pricing was market index based with a constant markup applied by the supplier. For 2023 through 2025, a transition period is in place between the near-term futures prices and the long-term price forecast from Siemens. Starting in 2026, the Siemens forecast was utilized exclusively for forecasted fuel oil prices.

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Q28. Are the sources and methodology to develop the fossil fuel price forecasts used for this IRP filing consistent with the Company's annual PSCR filings?

A28. Yes. 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 was 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.

Q29. Does the Company's fossil fuel procurement strategy enable reliable supply for its fossil generating sites?

A29. Yes. 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 ensure reliable and flexible supply while minimizing costs for its customers. For the Company's coal fired sites, 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 these sites. The Company holds coal inventory on-site to mitigate potential coal supply disruptions and maintain reliability of supply for its customers.

PART 3: FOSSIL FUEL FORECASTS FOR POTENTIAL SUPPLY RESOURCES ANALYZED IN THE IRP MODELING PROCESS

Q30. How were the natural gas price forecasts developed for potential future gas-fired generation assets described in the IRP process?

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A30. In addition to other resource options, the IRP model included combustion turbines (CTs) as well as combined cycle gas turbines (CCGTs) as alternative 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 ensure supply reliability. These firm agreements would have annual reservation charges to reserve capacity on the gas system. These costs were applied to the potential CCGT supply resources evaluated in the IRP process by scaling the costs based on plant capacity. The firm services estimated provide for a high level of natural gas supply reliability to a power plant.

Q31. Would you describe the Company's proposed changes in fuel type at the Belle River Power Plant?

A31. As described more fully by Witness Morren, the Company is proposing to convert the Belle River Power Plant to a peaking plant that would operate on natural gas instead of coal and oil.

Q32. What assumptions did the Company include related to the fuel supply for the Belle River Power Plant if it is converted to natural gas?

A32. The Belle River Power Plant is located adjacent to the Company's BWEC site and is approximately one mile from three major pipeline systems – Vector Pipeline, DTE Gas, and Great Lakes Gas Transmission. The Company intends to interconnect with the Vector lateral that currently serves BWEC in order to provide gas supply to Belle River Power Plant. This interconnect would allow for access to both the DTE Gas and Vector Pipeline systems for transportation services and to Washington 10 and Enbridge Gas for storage and balancing services. In addition, natural gas hubs at MichCon (upstream) and Dawn (downstream) provide liquid markets to procure natural gas supplies.

For modeling purposes, this IRP assumes that the Company would contract with Vector Pipeline for firm transportation services and with Enbridge Gas for firm transportation, storage, and balancing services and procure gas at the Dawn hub. The Company utilized its contracted rates for BWEC with Vector Pipeline and Enbridge Gas to estimate the cost of these services by scaling the costs based on the fuel requirements of the Belle River Power Plant if it is converted to natural gas. This assumption results in estimated annual fixed fuel costs of $7.4 million for transportation, $9.0 million for storage and balancing, and a one-time cost of $6.6 million to interconnect with the existing Vector lateral and to expand metering capacity to accommodate the additional load. Considering that Belle River is expected to operate as a peaking or cycling plant with a relatively low capacity factor, the entirely firm services described above are conservative estimates of the necessary gas supply services to reliably serve the plant. The Company will utilize a Request for Proposals to facilitate a competitive bidding process for gas supply services, which may result in lower costs than assumed in this IRP.

Q33. Are there any other new fossil-fueled generation assets that could be required in the future to meet the Company's forecasted electric demand?

A33. As described more fully by Witnesses Leslie, Manning, and Mikulan, the Company's proposed course of action (PCA) includes a placeholder dispatchable resource when the second two units of Monroe are retired in 2035. For purposes of this IRP, that resource is a new gas-fired CCGT with Carbon Capture and

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Sequestration (CCS) technology. The Company will monitor developments of emerging technologies and evaluate options for dispatchable generation in future IRPs.

Q34. How would the Company procure fuel supply for a potential future new CCGT with CCS?

A34. The IRP does not specify potential locations for resources, therefore the Company estimated fuel supply costs for a new CCGT with CCS based on a generic South Area location considering that the plant is forecasted to replace capacity when the Monroe Power Plant is retired. Similar to BWEC, the Company would enter into firm transportation and storage agreements for a new CCGT with CCS in order to ensure supply reliability. The Company estimated the costs of the transportation, and balancing services, resulting in estimated annual fixed fuel costs of $7.5 million for transportation and $8.7 million for storage and balancing.

Q35. Does this complete your direct testimony?

A35. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TIMOTHY J. LEPCZYK

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF TIMOTHY J. LEPCZYK

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

A1. My name is Timothy J. Lepczyk (he/him/his). My business address is DTE Energy Company, One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

Q2. What is your position and on whose behalf are you testifying?

A2. I am Assistant Treasurer and Director of Corporate Finance, Insurance and Development for DTE Energy Company (DTE Energy) and its subsidiaries including DTE Electric Company (DTE Electric or Company). I accepted the position of Assistant Treasurer and Director of Corporate Finance in August 2021. I am testifying on behalf of DTE Electric.

Q3. What are your responsibilities as Assistant Treasurer and Director of Corporate Finance for DTE Electric?

A3. I am responsible for assisting the Treasurer in managing the capital needs of the Company. These responsibilities include managing corporate liquidity and financing activities such as the raising of both equity capital and capital markets debt for DTE Energy, DTE Electric, and DTE Gas Company (DTE Gas). I assist in maintaining relationships with the commercial and investment banking community, interact with the rating agencies, and execute corporate financial policies, particularly in the areas of balance sheet management, debt issuances, and agency ratings. In addition, I manage the Company's capital investment approval and review process along with managing the Company's property and liability insurance function.

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Q4. What is your educational background?

A4. I graduated from Georgetown University in 2004 with a Bachelor of Business Administration degree, with a concentration in International Business. In 2008, I graduated with my Masters of Business Administration (MBA) from the University of Michigan, with a focus in Finance and Corporate Strategy.

Q5. What is your professional experience?

A5. I began my employment with Ford Motor Company in the summer of 2004 as a financial analyst within that company's Dearborn Stamping facility. In 2006, I left to pursue my MBA. In 2008, after graduation, I went to work for Booz & Company, a management consultancy, where I focused on the automotive and industrial sectors. I worked at Booz & Company from 2008 until 2013 when I joined DTE Energy.

In 2013, I joined DTE Energy as a Manager on the Corporate Strategy team where I was the lead analyst for various projects and studies primarily relating to the Gas Storage and Pipeline business. In 2014, I formally accepted a position within the Gas Storage and Pipeline team as Manager in their strategy group where I was responsible for various economic analyses (e.g., natural gas supply and demand fundamentals) and for assessing potential new acquisition opportunities. In 2016, I accepted the position of Manager for the Corporate Development team where I was responsible for managing DTE Energy's capital investment process and various valuation processes (for example, DTE Energy's annual Goodwill impairment assessment). In addition, I led broader strategy initiatives including the analysis, which ultimately led to the decision to spin off the Midstream business segment.

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In 2021, I accepted my current position, Assistant Treasurer and Director of Corporate Finance, Insurance and Development.

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

A6. Yes, I sponsored direct and rebuttal testimony in DTE Electric's 2022 main electric rate Case No. U-20836.

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to support the reasonableness of an updated Financial Compensation Mechanism ("FCM") for future Power Purchase Agreements ("PPAs") and to describe the appropriateness of the after-tax weighted average cost of capital within the incentive. In addition, with respect to the remaining net book value (NBV) and decommissioning costs associated with the proposed early retirement of coal-fired generation, I propose to recover these amounts by classifying them as regulatory assets and then recovering those assets through amortization in base rates.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-15.1	L-1	Depreciation Scenarios – Status Quo
A-15.1	L-2	Depreciation Scenarios – Acceleration
A-15.1	L-3	Depreciation Scenarios – PCA
A-15.2		Impact of Securitization on Capital Structure
A-15.3		Securitization Impact – Moody's
A-15.4 - Confidential		Moody's Credit Opinion May 31 2022

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

A9. Yes, they were.

PPA Financial Compensation Mechanism

Q10. Witnesses Leslie and Hernandez discuss the Company's proposal for an update to the Company's current financial compensation mechanism on PPAs as part of this Integrated Resource Plan (IRP). Why does the company believe that it would be reasonable for the MPSC to approve this financial incentive on PPAs contracted by the utility?

A10. There are three primary reasons.

1. PPAs are credit negative. PPAs are long-term obligations of the utility that are similar to leases. Like leases, monthly payments are guaranteed and obligated to be paid by the utility to third parties without the long-term benefits of ownership. At the end of the PPA period, like a lease, if the asset is still needed, the third party will likely renegotiate with the utility and re-contract at market rates, as no other obligation is owed to the utility. Additionally, like leases, the obligation is disclosed to investors and rating agencies as a commitment owed by the utility. These commitments, depending on the methodology applied by the rating agency and/or credit analyst, are often net present valued, in whole or in part, and added to the debt balances of the company for their calculations of the various credit metrics the utility uses. An FCM will partly offset this impact.

2. PPAs can increase the cost of equity. A PPA is a lost opportunity cost for the utility, as the return on investment is transferred from the utility to a third party. While DTE Electric maintains a strong backlog of capital investment opportunities it considers prudent, there is a limit on the amount of investment that can be undertaken before affordability is challenged. As

a result, the lost opportunity (i.e., opting for a PPA in lieu of utility-owned generation) has the effect of reducing the rate base growth that the utility would have otherwise generated. Utility investors, assuming risks are equal, will favor utilities with higher growth rates, thereby increasing the cost of equity for the slower growth utility. The FCM will partly offset this impact.

3. Lastly, a FCM is fairer to utility stakeholders. The project which is supplying the PPA is financed on the back of the utility's customers and investors. The obligations borne by the credit worthy utility provide the foundation for the project to gain more favorable debt and equity financing. If the utility was not credit worthy, the terms a project sponsor would receive on its financing would be considerably worse. For example, the sponsor would have higher interest rates, more restrictive covenants in its financing agreements, and equity investors would no doubt expect a higher return. The credit worthiness of the utility, which is driven by its strong, well-capitalized balance sheet, provides the means for the efficient financing and equity returns of the developer's project. At the end of the PPA period, the project, assuming the project was well executed and well operated, would likely have its debt paid off and have provided a return for the project's equity holders. The FCM provides some fairness as it compensates the utility's debt and equity holders, who are negatively impacted during the PPA period for the material benefits that the project sponsors received.

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Q11. Is the Commission authorized to compensate the utility for PPA risks?

A11. Yes. Public Act 341 explicitly authorizes the Commission to approve financial incentives for the utility when entering PPAs.

Q12. Did Public Act 341 address PPAs and a financial compensation mechanism?

A12. Yes. PA 341 (MCL 460.6t(15)) states:

> "For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital. *["WACC"]*"

Q13. Do other utilities in Michigan incorporate a financial compensation mechanism on their PPAs?

A13. Yes. Consumers Energy, Indiana Michigan Power, and Upper Peninsula Power Company (UPPCO) have all requested and received authorization to implement an FCM for PPAs.

Q14. Does DTE Electric currently have an FCM?

A14. Yes. The Company is currently authorized to apply an FCM on future Voluntary Green Pricing ("VGP") PPAs equal to the Levelized Cost of Energy ("LCOE") difference between a self-build or Build Transfer Agreement ("BTA") project and the PPA, multiplied by a financial incentive factor of 30%, multiplied by MWh sold under the PPA. The FCM was approved by the Commission in its June 9, 2021, order in Case Nos. U-20713 and U-20851. This FCM is restricted to a value capped at the total value of the PPA payments (based on the PPA rate times the MWhs under the PPA(s)) multiplied by DTE Electric's current after-tax WACC on total capital (currently 5.46%). This financial incentive would be added to the cost of the selected PPA and would be recovered through the subscription fee for the VGP program. To date, this FCM has not been implemented, though it is projected to be used for the PPA related to Savion Calhoun.

Q15. Is DTE Electric's current FCM an effective incentive to address the PPA risks discussed above?

A15. No. The negative impacts listed above in Q10 / A10 – the fact that PPAs are credit negative, they can increase the cost of equity, and the assets from which they derive are financed on the good standing of DTE Electric and its customers – are not directly addressed by the shared savings FCM that is currently approved. The negative impacts from PPAs correlate directly with the size (i.e., dollar value) of the PPAs, and thus, the ideal FCM would be designed to tie explicitly to the size of the PPA payments. Instead, the current FCM framework, basing the incentive on the difference between DTE Electric's self-build LCOE and the PPA cost, detracts from this objective. The financial impact from the shared savings mechanism can be materially below that of a WACC-based methodology. For example, I estimate that for a utility self-build project with an LCOE 10% above the price of a comparable PPA, the shared savings methodology results in an FCM approximately 55% that of one based upon WACC (the basis for the methodology approved for several peer utilities).

In addition, the current FCM is limited to the VGP program only and would not apply to new resources such as solar included in the Company's proposed course

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of action ("PCA"). However, the negative impacts discussed above are present from all PPAs, regardless of whether the PPA stems from VGP, base build, or Public Utility Regulatory Policies Act ("PURPA") assets.

The current FCM is also difficult to determine. While it is based on a shared savings mechanism, it is not clear at what point the shared savings should be determined – at the point of project evaluation/selection or at the time the project commences operations. This is an important factor to understand as a project's contract price could be amended any time prior to commissioning (if both parties agree and if the MPSC approves the amendment), which would then impact the shared savings calculation as one of the reference points for the mechanism. Furthermore, were the DTE Electric-owned asset to be derived from a BTA, the figure that the calculation is based off may or may not be a negotiated number that could change throughout the negotiation and construction process. Therefore, the current FCM results in a high degree of uncertainty and lack of transparency.

These limitations - the low incentive level available under the approved FCM methodology, the FCM's applicability being limited to the VGP program, and the variability of the prices on which the calculation is based - make the existing FCM inadequate at addressing the PPA risks identified above and supporting the implementation of the PCA.

Q16. What are the details of the financial incentive you are proposing in this case?

A16. DTE Electric is proposing an FCM based upon the after-tax WACC of its total capital structure (currently approved 5.46%) applied to all PPA payments under the applicable contracts. First, a WACC-based FCM achieves the aforementioned priority of tying the Company's financial compensation directly to the size of the PPA payments it makes. Second, this framework is consistent with the FCMs of other utilities in Michigan. Per Consumers Energy Case No. U-21090, "the parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%." In Case No. U-20350, UPPCO also received approval to implement an FCM that was based upon Consumers Energy's then-applicable WACC of 5.88%. In Case No. U-20591, the Indiana Michigan Power settlement stated they may include an FCM on renewable resources that mirrored the methodology outlined for Consumers Energy in Case U-20165 in their next IRP.

Also, the Company proposes to include PPA payments for new and any modified PPAs under this mechanism, as the negative impacts to the Company from PPA payments are present regardless of which program the underlying asset is part.

The FCM methodology and applicability to PPAs would be specified in any requests for proposal documents for acquiring new resources to implement the PCA, and the cost of the FCM would be incorporated in the financial assessment of PPAs in the bid evaluation process. The inclusion of the FCM on customer bills, along with the mechanism's collection and accounting, would – for VGP-related PPAs – follow the current process. For FCMs applied to PPAs outside of the VGP program, we will seek recovery in future regulatory filings.

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Q17. Does the Company's proposed FCM methodology include deferred taxes and short-term debt in the total capital to calculate the incentive?

A17. Yes. The Company is requesting an FCM in this proceeding that includes deferred taxes and short-term debt in its capital structure. Based on the premise that the financial incentive is meant to offset the lost opportunity cost for investments, it would be reasonable to use DTE Electric's permanent capital structure (excluding deferred taxes) to compensate equity and debt holders (DTE Electric's pre-tax WACC on its permanent capital structure is 8.79%). Using the WACC as proposed does understate the incentive as the total capital structure on which the WACC of 5.46% is based includes a material weighting for deferred taxes. Deferred taxes are less relevant considerations for the FCM because temporary book and tax depreciation differences – the primary driver behind the accumulation of deferred taxes – do not derive from PPA payments. However, based on input from stakeholders in Case Nos. U-20713 / U-20851 (VGP case) and consistent with the methodology approved for Consumers Energy Case Number U-21090, DTE Electric has not developed the FCM under this framework.

<u>Recovery Methodology of Regulatory Asset Request</u>

Q18. Can you provide context for the Company's regulatory asset request that includes the recovery of the remaining NBV of the proposed early retirement of coal-fired assets at the Belle River and Monroe Power Plants?

A18. Yes. I will discuss the NBV portion of the request; Witness Uzenski will address the respective Belle River and Monroe power plant decommissioning costs and ongoing capital expenditures at Monroe Power Plant.

The PCA calls for the cessation of coal (and the subsequent conversion to a natural gas peaking resource at the Belle River Power Plant in 2025 and 2026. In addition, it proposes the early retirement of the Monroe Power Plant, with units 3 and 4 retiring in 2028 before units 1 and 2 are retired in 2035. This acceleration, if approved as part of the PCA, would result in unrecovered NBV at time of retirement because the depreciation schedules reflected in existing rates have been based on the previously determined remaining useful lives for these facilities (i.e., 2041 through 2044 for Monroe Power Plant and 2030 for Belle River Power Plant). The NBV amounts included in rate base derive from reasonable and prudent investments to maintain the facilities properly and have been reviewed and approved in rate cases. Absent regulatory action, the remaining NBV at the time of the plant retirements would be considered unrecovered. Without resolution of this issue and an appropriate recovery mechanism, the Company would not be able to implement the PCA and proceed with the early retirements given the significant financial consequences.

At the end of 2024, the remaining NBV associated with coal-fired assets at these facilities is estimated at $3.3 billion ($3.1 billion associated with total plant at Monroe Power Plant; $0.2 billion at Belle River for coal-handling assets; see Exhibit A-15.1). Furthermore, as supported by Witness Morren and shown in Exhibit 6.1, the Company anticipates an incremental $0.7 billion of maintenance capital will be required to support ongoing operations at the Monroe Power Plant during 2025 through its planned retirement in 2035.

This situation is not unique to DTE Electric. Utilities in Michigan and across the country are accelerating plant retirements due to a variety of factors, including environmental regulation compliance or emission-reduction commitments, and many have pursued regulatory actions to address the remaining net book values as I reference further in my testimony.

Q19. How does the Company propose recovering the remaining net book value of the proposed retirement units?

A19. The Company proposes to recover the remaining NBV of the assets by classifying the amounts as regulatory assets and amortizing these assets through base rates. For Belle River, the assets to be retired (with an estimated NBV of $209 million at year-end 2024; see Exhibit A-15.1) include all the structures and equipment used exclusively for handling coal. As supported by Witness Morren, this includes unloading equipment, storage, hoppers, conveyors and weighing equipment. As described by Witness Uzenski, the Company is requesting regulatory asset treatment and proposing that the actual NBV be reclassified to a regulatory asset in its first general rate case filed after receiving an order in the instant IRP case. Amortization of this regulatory asset would extend 10 years beyond the planned cessation of coal use in 2026 (thus, until 2036). This timing aligns with when the underlying plant assets would have reached a zero net book value through normal depreciation.

The Monroe Power Plant, which the Company is proposing to reclassify as a regulatory asset, has an estimated NBV of $3.1 billion at year-end 2024 (see Exhibit A-15.1). As described by Witness Uzenski, the Company is proposing that the actual NBV be reclassified to a regulatory asset in its first general rate case filed after receiving an order in the instant IRP case. The Company proposes to record the additional capital expenditures at Monroe Power Plant (currently estimated at $730 million for 2025 through 2035; see Exhibit A-15.1, line 25, columns (h) through (r)) to the regulatory asset account for review in future general rate cases. Amortization of the regulatory asset would extend 15 years from the retirement date of the last two units in 2035 (thus, until 2050). This timing is expected to result in recovery of the full NBV by 2050, which is the year by which the Company aspires to achieve net zero carbon emissions.

Q20. What is the impact to customer revenue requirement of reclassifying the remaining net book value from plant to a regulatory asset?

A20. There is essentially no impact because rate base does not change, and collection of the asset occurs over the same time period that would have applied if the plants were not retired early. As shown in Exhibit A-15.1, Schedule L-3, line 26, the impact to annual depreciation and amortization expense is negligible (i.e., less than $10 million annually).

Q21. How have other jurisdictions addressed the recovery of remaining net book value associated with the early retirement of coal-fired generating units?

A21. There does not appear to be any universal approach to the recovery of coal-fired generation facilities that are retired early. However, several jurisdictions that have recently dealt with the early retirement of generating units have recognized the need to ensure the means of recovery for the utility, including earning a return on the remaining value until recovery is complete. Some examples include:

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- In Oregon in 2010, in response to legislation requiring the elimination of coal generation by 2030, the Oregon Public Utility Commission authorized Portland General Electric in Order No. 10-478 to accelerate depreciation of the coal-fired Boardman plant and recover the increased depreciation expense through a tracker to facilitate the shut-down of the plant by 2020.
- In Georgia, in Case No. 31958 in 2012, that state's Public Service Commission authorized Georgia Power to reclassify the remaining book values for facilities that are retiring early as regulatory assets and to recover those balances via amortization. In April 2015 in Cases 34218 and 36498, the commission ordered that the coal-fired power plants Branch, Hammond, and McIntosh be given Regulatory Asset treatment and amortized over the period of their remaining useful lives. The Commission also ruled in August of 2016 that the coal-fired power plant Mitchell be treated as a regulatory asset with a 3-year amortization schedule starting in January 2020.
- In Kentucky, American Electric Power subsidiary Kentucky Power utilizes a rider to recover the costs related to the 2015 retirement of the coal-fired Big Sandy Unit 2 plant, including a return on the investment (from Case No. 2014-00396). The Kentucky Public Service Commission authorized the rider as part of a rate case settlement adopted in June 2015.
- In Florida, the Public Service Commission has – in Order No. PSC-15-0401-AS-EI (September 2015) and in Order No. PSC-16-0506-FOF-EI (November 2016) - authorized Florida Power & Light to classify the book balances associated with the coal-fired facilities Cedar Bay and Indiantown as regulatory assets and to recover these balances over a period of

approximately ten and nine years, respectively. The Cedar Bay plant was retired in 2016; the Indiantown plant was retired in 2020.

- In Washington, Puget Sound Energy's 2017 rate case decision (Dockets UE-170033 and UG-170034) called for modifications to the depreciation schedules for the company's investment in the coal-fired Colstrip plant, aimed at allowing units 1 and 2 to close by mid-2022 and units 3 and 4 to close by Dec. 31, 2027.
- In Indiana, in December 2019, the state's regulatory Commission authorized Northern Indiana Public Service Company ("NIPSCO") to create a regulatory asset equal to the remaining NBV of its R.M. Schahfer and Michigan City coal-fired generating units at the date of each unit's retirement to be amortized through December 31, 2032 (Cause No. 45159). Also in that state, in a 2020 rate case decision for Duke Energy Indiana (Cause No. 45253), the Indiana Utility Regulatory Commission approved the company's proposal to accelerate the depreciation schedules of three coal plants — Gallagher, Cayuga and Gibson — to reflect the fact that "the useful lives of coal-fired assets are declining in relation to what we may have thought they would be 15 or even five years ago."
- In Wisconsin, both Wisconsin Electric Power Company ("WEPCO") and Wisconsin Power and Light Company provide examples.
    - In December 2019, Wisconsin's Public Service Commission (in Case No 5-UR-109) addressed the $400 million remaining book balance associated with WEPCO's Pleasant Prairie Power Plant. $100 million (associated with environmental controls) was to be securitized, while $300 million was to be recovered through

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WEPCO's normal revenue requirement. The remaining balance of the plant (which was retired in 2018) has been reclassified as a regulatory asset, which – at the time of the 2019 order - had approximately 20 years remaining.

- Wisconsin Power and Light Company, in a December 2021 ruling (Case No. 6680-UR-123), was authorized to transfer the remaining NBV of the ~400MW Edgewater 5 coal-fired generating facility to a regulatory asset. In addition, the Wisconsin PSC found it reasonable that the NBV of Edgewater 5 shall be recovered based upon a levelized cost of recovery basis upon retirement through June 2045. The levelized cost of recovery included both return on and of investment.

- In Virginia, in November 2020, the Virginia State Corporation Commission directed American Electric Power Company subsidiary Appalachian Power, in Case No. PUR-2020-00015, to book unrecovered coal plant balances associated with plants retired early as regulatory assets that would be amortized over a 10-year period. The unamortized balance was included in rate base cash return at the company's overall weighted average cost of capital.
- In North Carolina, in March 2021 (Docket No. E-7, Sub 1214) and April 2021 (Docket No. E-2, Sub 1219) decisions for Duke Energy subsidiaries Duke Energy Carolinas LLC and Duke Energy Progress LLC, respectively, the North Carolina Utilities Commission authorized the company to amend the depreciation rates for certain coal-fired generation facilities that are being retired early to match the remaining lives of the plants.

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- In Idaho, in June 2022, the state's Public Utilities Commission found it fair, just, and reasonable to approve Idaho Power's application to establish accelerated depreciation rates that fully depreciate the coal assets of the 2,123-MW Jim Bridger power station by December 31, 2030 (Case No. IPC-E-21-17).
- In June 2022 in Case U-21090, the Michigan Public Service Commission permitted Consumers Energy (CE) to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through CE's proposed regulatory asset treatment, with a 9.0% return on equity after the retirement date of those units, as part of CE's electric rates over the current design lives of those units.

Q22. Why is the Company not proposing to recover the remaining net book value by the proposed retirement dates?

A22. The Company is not proposing to recover the remaining NBV by the proposed retirement dates (i.e., via accelerated depreciation) in the PCA due to the significant burden on customers in the form of increased customer rates. Based upon the planned dates for retirement or the cessation of coal use at these facilities, accelerated depreciation would potentially increase customer revenue requirements by approximately $500 to $700 million annually through 2027 as shown on Exhibit A-15.1, Schedule L-2, page 1, line 26. (At a high level, this would represent an approximately 10% increase in overall customer revenue requirement.). The accelerated retirement dates are driven by the Company's environmental regulation compliance, carbon reduction goals, and other factors considered as part of the IRP analysis to develop the most reasonable and prudent course of action as discussed by Witnesses Leslie and Mikulan. Recovery of the NBV over a longer time frame balances the revenue requirement impacts of current customers with those of future customers.

Q23. Should the Commission consider any form of base rate recovery of the investments in the retirement units that does not include a return on the investment?

A23. No. Such an approach would have serious detrimental impacts. Were the Commission not to authorize a method of recovering the remaining NBV of the plants, including full recovery of regulatory asset classification at the same time the PCA is approved, the Company would be required to write off a portion of the NBV of Monroe Power Plant and Belle River Power Plant and immediately record an impairment for accounting purposes (per Accounting Standards Codification ASC-360; Property, plant, and equipment). Such an outcome is not reasonable or prudent. The investments in these plants were necessary to maintain the facilities in a safe, reliable manner, reasonable at the time they were made, and approved by the Commission in numerous rate case orders over the span of many years. Changed circumstances driven by public policy do not render those investments unnecessary or unreasonable. The reasonableness of an investment, and by extension, its appropriateness for recovery through rates, should always be considered on the basis of what was known at the time the investment decisions were made.

Q24. Could you please discuss the impact of financing an early retirement without a return?

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A24. Utilities make investments in long-term assets that can take decades to recover. Investments that have long time horizons often require higher returns as macroeconomic factors, technology, state or federal public policy, and legislation can change over time. The stability provided by Michigan's regulatory environment allows the Company to secure lower cost long-term financing and encourages investments that improve safety, reliability, and affordability. One of the key criteria used by rating agencies is the quality of a utility's regulatory environment and as noted by both Moody's and S&P Global, the recovery of investments and the ability to earn a reasonable return are key components of that analysis:

> *"A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score." [Moody's June 23, 2017, Regulated Electric and Gas Utilities Rating Methodology Report, page 7]*

> *"The utility can fully and timely recover all its fixed and variable operating costs, investments and capital costs (depreciation and a reasonable return on the asset base)." [S&P Global November 19, 2013, Key Credit Factors for the Regulated Utilities Industry Report, page 7]*

Furthermore, S&P Global, in April 2022, argued,

> *"In the near term, it is imperative for utilities to recover the outstanding NBV of the many coal plants that are being retired early. In addition to recouping remaining investments in coal units, the recovery will support a utility's financial measures while new generation investments are being constructed and not being recovered in rates." [S&P Global April 11, 2022, Utilities' Early Retirement of Coal Generation Increases Uncertainty Over Recouping Stranded Investments, page 3]*

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To the extent the Company is forced to take an impairment on investments that were previously deemed reasonable and prudent, such an action would raise serious questions regarding the stability of Michigan's regulatory environment and ultimately negatively impact or raise the Company's long-term financing costs, thereby discouraging future investments.

Furthermore, it would encourage recovery of assets over shorter timeframes in order to avoid the uncertainty of regulatory outcomes. Such an action would drive large increases in customer rates. In contrast, allowing assets to be financed over longer periods of time provides a more balanced approach for customers.

Q25. Could you please discuss securitization and the role it has played in DTE Electric's other recent early retirements of generating units?

A25. Securitization is the financing method whereby a discrete asset or group of assets (e.g., storm costs, unrecovered net book value) are separated from the utility and financed with securities whose credit quality is separated from that of the utility in order to achieve higher credit ratings and lower financing costs. In order to accomplish this, the utility sells the revenue stream and other entitlements and property created by the financing order to a newly established special purpose entity ("SPE" or "Issuer") in a transaction which represents a "true sale" for bankruptcy purposes. This sale insulates the securitization property from the creditors of the utility and, thereby, from the credit risk of the utility. The SPE then issues bonds backed by the securitization property and "other collateral" to investors / bondholders. A trustee acts on behalf of bondholders, remits payments to bondholder and ensures bondholders' rights are protected in accordance with the

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terms of the financing documents. The company performs routine billing, collection, and reporting duties as the servicer for the Issuer pursuant to a servicing agreement between the company, the Issuer and the trustee. In addition to the bankruptcy remote status of the Issuer, credit enhancements, such as a capital contribution to the Issuer and a true-up mechanism, are necessary to reach the rating standard for this type of securitization, which is the highest rating (a "triple-A rating") from each of two or more of the major rating agencies.

The Commission authorized DTE Electric to use securitization financing to recover the remaining book value for its River Rouge coal-fired generating facility (as well as tree trimming surge amounts that had been recorded as a regulatory asset) (in Case U-21015). In total, this amounted to approximately $230 million.

Q26. Could you please discuss the impacts of securitization on the Company's financial standing?

A26. Similar to PPAs, a securitization creates a long-term financial obligation that has an impact on the credit of the Company. Unlike PPAs, however, securitization debt is included on the Company's balance sheet. Therefore, its impact on the Company's capital structure is readily observed. The most significant aspect in which a securitization negatively impacts the Company is with regard to the Company's credit rating metrics. Moody's includes securitization debt as part of the capital structure of the company and includes the securitized debt and related cash flow in the calculation of financial metrics despite that debt being considered non-recourse to the Company. Non-recourse means that the loan is secured by collateral (e.g., property) and, if the borrower defaults, the lender can seize the collateral but cannot seek out the borrower for any further compensation, even if the collateral does not cover the full value of the defaulted amount. This inclusion of securitization debt adversely impacts the Company's corporate rating. Specifically, Moody's stated in their publication *Corporate Methodologies for Electric and Gas Utilities* from June 23, 2017:

> *"In general, we view securitization debt of utilities as being on-credit debt, in part because the rating associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in company's ratios by including the securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal)."*

Moody's methodology explanation makes it clear that securitizations are in fact negative for a company's credit ratings.

Q27. Could you please discuss the use of securitization proceeds?

A27. Historically, the Company has used the proceeds from securitization to pay down debt and equity in equal portions. That may have been reasonable when the balance of securitization debt was relatively modest (such that the capital structure remained balanced when including securitization), as in the case of the River Rouge / tree trimming securitizations. However, the magnitude of incremental securitization debt (e.g., associated with Monroe Power Plant's remaining NBV) that additional securitization financings would place on the Company's balance sheet would skew the relative balance of debt and equity, which would have negative impacts on the Company's financial health (as discussed below in my testimony). Exhibit A-15.2 provides an illustration of this impact using the Company's most recently approved

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capital structure, and demonstrates that doing so would skew the balance toward using more debt than equity. A securitization of the remaining NBV at Monroe and Belle River Power Plants at the time of their retirements would shift the capital structure toward 60% debt and 40% equity (from a 50% / 50% split today).

Q28. Is securitization the preferred method of recovering the remaining net book values associated with the potential early retirement of the Company's remaining coal plants as proposed in this case?

A28. No. In fact, it appears that the issuance of securitization bonds for early coal retirements is much less common than allowing the assets to be recovered through a regulatory asset with a return of and on unrecovered balances. Due to the securitization undertaken for River Rouge and tree trimming surge expenses, DTE Electric has approximately $230 million securitization debt reflected on its Generally Accepted Accounting Principles ("GAAP") accounting statements. In comparison to WEPCO, for example, (which issued approximately $120 million of securitization bonds), the percentage of securitization debt relative to rate base is higher for DTE Electric: approximately 0.7% for WEPCO, when securitization debt is compared against parent WEC Energy's total estimated electric rate base versus approximately 1.1% for DTE Electric, following the securitization of River Rouge and tree trimming surge expenses. Were the post-retirement balances at Monroe and Belle River Power Plants to be securitized and that debt included in the calculation, the percentage of securitized debt to rate base would increase to approximately 14.7%.

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In addition, securitizing the remaining NBV associated with the Monroe and Belle River Power Plants would have a materially adverse impact to the Company's Cash Flow from Operations – Working Capital / Adjusted Debt ("CFO-WC/Debt"), a critical metric for Moody's. Per Exhibit A-15.3, this negative impact is assessed at approximately 380 basis points, or 3.8%. In Moody's May 31, 2022, Credit Analysis on DTE Electric Company, the agency published DTE Electric's last twelve months ("LTM") March 2022 CFO-WC/Debt at 20.5% (page 2[1]). Moody's also noted that, if the Company's credit metrics deteriorate such that the ratio of CFO-WC/Debt falls below 20.0% for a sustained period of time, a downgrade could be possible. A 380-basis point reduction in our CFO-WC/Debt would result in a ratio of 16.7% (20.5% - 3.8%), which would be materially below our downgrade trigger and may result in a negative ratings action. A prospective downgrade may result in higher debt costs for the company (and, as a result, would negatively impact customer affordability).

DTE Electric submits that it is much more common and preferrable to recover the remaining NBV of the Monroe and Belle River Power Plant coal assets through the more traditional cost recovery method, specifically as a regulatory asset that is amortized over a reasonable timeframe that aligns with the Company's carbon reduction goals. This approach balances customer impacts and the utility's financial health to support the energy transition.

Q29. Are there any other components of the regulatory asset request?

[1] Source: Moody`s Investors Services – DTE Electric Company Credit Opinion dated May 31, 2022 , See Exhibit A-15.4 CONFIDENTIAL

A29. Yes, per Witness Uzenski's testimony, the Company is also requesting that decommissioning costs for Monroe and Belle River Power Plants be included in the regulatory asset.

Q30. How would the method of recovery impact the Company's PCA?

A30. As discussed by Witness Leslie, DTE Electric's PCA is a fully integrated proposal that ties the Company's generation transformation to other proposals such as the regulatory asset and financial compensation mechanism. Therefore, any modification to, or rejection of, a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

To implement the PCA, the Company must be in a position to recover the remaining NBV of retired coal assets in a manner that preserves customer affordability and the Company's credit and financial profile.

Any recovery mechanism that resulted in significant rate increases or the Company incurring an impairment or financing assets over a long period of time without proper compensation for the capital needed to finance those assets would not be a prudent course of action. Increasing the Company's leverage through the use of securitization would pressure and potentially lower our credit ratings at Moody's and therefore limit the financial flexibility of the Company and hinder the Company's ability to make necessary capital investments proposed in the PCA

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(e.g., the deployment of solar and storage). Recovery of the remaining NBV via accelerated depreciation is not the preferred path given the significant burden that would place on customers in the form of increased customer revenue requirement.

The Company's proposal to recover the remaining NBV of the retired assets over a period of up to 15 years beyond the retirement date, as supported by Witness Uzenski, is a balanced proposal that would have no material impact on customer revenue requirement and preserve the Company's credit and financial profile and is necessary for DTE Electric to proceed with the PCA as proposed.

Q31. Does this complete your direct testimony?

A31. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

THERESA M. UZENSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF THERESA M. UZENSKI

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

A1. My name is Theresa M. Uzenski (she/her/hers). 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 work experience and what position do you currently hold at DTE Energy?

A4. I have worked for DTE Energy or one of its affiliated regulated utilities for thirty-three years in various accounting, finance, and management positions. I am currently the Manager of Regulatory Accounting for DTE Electric Company as well as 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 (Commission or MPSC) 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. To what extent have you participated in prior rate cases and other regulatory proceedings?

A7. I have sponsored testimony in the following cases:

U-11222	Michigan Consolidated Gas Company (MichCon) Depreciation
U-13898	MichCon UETM
U-14702	Detroit Edison 2006 PSCR Plan
U-15160	Detroit Edison Enhanced Security Cost Recovery
U-15244	Detroit Edison Choice Incentive Mechanism 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 RETM Reconciliation
3	U-16246-R	Detroit Edison 2010 RETM Reconciliation
4	U-16356	Detroit Edison 2009 REP Reconciliation
5	U-16472	Detroit Edison 2010 Rate Case
6	U-16574	Detroit Edison 2010 UETM Reconciliation
7	U-16582	Detroit Edison 2011 REP Plan
8	U-16769	MichCon Depreciation
9	U-16952	Detroit Edison 2011 CIM Reconciliation
10	U-16956	Detroit Edison 2011 RETM Reconciliation
11	U-16964	Detroit Edison 2011 UETM Reconciliation
12	U-17302	DTE Electric Company 2016 REP Plan Update
13	U-17437	DTE Electric Company Transitional Cost Recovery Mechanism
14	U-17767	DTE Electric Company 2014 Rate Case
15	U-17999	DTE Gas Company 2015 Rate Case
16	U-18014	DTE Electric Company 2016 Rate Case
17	U-18122	DTE Electric Company Customer 360 Program Accounting
18	U-18255	DTE Electric Company 2018 Rate Case
19	U-18419	DTE Electric Company Certificates of Necessity
20	U-18999	DTE Gas Company 2018 Rate Case
21	U-20106	DTE Gas Tax Cut & Jobs Act – Credit A
22	U-20105	DTE Electric Tax Cut & Jobs Act – Credit A
23	U-20162	DTE Electric Company 2018 Rate Case
24	U-20298	DTE Gas Tax Cut & Jobs Act – Credit C
25	U-20561	DTE Electric Company 2019 Rate Case

Line No.		
1	U-20642	DTE Gas Company 2019 Rate Case
2	U-20940	DTE Gas Company 2021 Rate Case
3	U-21015	DTE Electric Company 2021 Securitization
4	U-20836	DTE Electric Company 2021 Rate Case

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Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. As supported by Witness Leslie, and as further discussed by Witness Lepczyk, the Company is proposing regulatory asset treatment for the remaining net book value (NBV) of a portion of the Company's Belle River Power Plant and the related cost to decommission the assets, and regulatory asset treatment for the remaining net book value of the Company's Monroe Power Plant, plus decommissioning costs. My testimony describes the accounting proposal in more detail. I am also requesting amortization of the deferred regulatory assets commensurate with recovery of the expense in base rates.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-16	Amortization Expense Illustration

Q10. Was this exhibit prepared by you or under your direction?

A10. Yes, it was.

Belle River Power Plant

Q11. What assets are being retired at the Belle River Power Plant?

A11. As described and supported by Witness Mikulan, the Belle River Power Plant, currently fueled by coal, will be converted to a natural gas peaking resource in 2025 and 2026 (Unit 1 and Unit 2, respectively) as part of the Company's proposed course of action (PCA). The plant assets to be retired include all the structures and equipment used exclusively for handling coal such as unloading equipment, storage, hoppers, conveyors and weighing equipment, as supported by Witness Morren.

Q12. What is the net book value of the Belle River coal handling assets that will be retired?

A12. The net book value of the assets on December 31, 2021, was $261 million and is estimated to be approximately $209 million as of December 31, 2024, as supported by Witness Lepczyk. The Company is requesting regulatory asset treatment and proposing that the actual net book value be reclassified to a regulatory asset in its first general rate case filed after receiving an order in the instant IRP case.

Q13. What is the expected life of the Belle River Power Plant?

A13. The estimated depreciable life of a steam unit is defined by the initial date of service and the final date of service, i.e., the period the plant is available and capable of generating electricity. Therefore, there is generally no difference in the life for depreciation purposes from the engineered design life unless a plant is targeted for early retirement. As stated in DTE Electric's depreciation case, No. U-16117, the overall depreciable life of our steam units is 65 years. Depreciation rates are periodically updated and reset by considering the undepreciated balance and the remaining useful life of assets (among other factors). With the conversion of Belle River Power Plant from coal-fired to natural gas-fired, the PCA reflecting a final retirement by 2040, and a portion of the assets being retired in 2026, the remaining depreciable life will need to be updated in the Company's next depreciation study.

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Q14. Is there a cost to remove the coal handling equipment from Belle River?

A14. Yes. These costs are in addition to the net book value of the plant assets. The Company estimates those removal / decommissioning costs at $30 million and proposes that the actual costs incurred be recorded to a regulatory asset. (See workpaper TMU-1.)

Monroe Power Plant

Q15. What assets are being retired at the Monroe Power Plant?

A15. As described and supported by Witness Mikulan, two of the generating units at the Monroe site are targeted for retirement in 2028, and retirement of the two remaining units is targeted for 2035 as described in the PCA.

Q16. What is the net book value of the Monroe Power Plant that will be retired?

A16. The net book value of the assets on December 31, 2021, is $3.0 billion and is projected to be approximately $3.1 billion as of December 31, 2024, as supported by Witness Lepczyk. The Company is requesting regulatory asset treatment and proposing that the actual net book value be reclassified to a regulatory asset in its first general rate case filed after receiving an order in the instant IRP case.

Q17. What if additional capital costs are incurred after the date the NBV is initially reclassified to a regulatory asset?

A17. The Company proposes to record the additional capital expenditures to support ongoing operations at the Monroe Power Plant through its planned retirement in 2035 to the regulatory asset account for review in future general rate cases. These capital expenditures are supported by Witness Morren.

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Q18. What is the estimated cost to decommission the Monroe Power Plant?

A18. The Company estimates removal / decommissioning costs at $300 million and proposes that the actual costs incurred be recorded to a regulatory asset. These costs are in addition to the net book value of the plant assets. (See workpaper TMU-1.)

Regulatory Asset Request

Q19. Can you clarify which costs you are proposing be deferred to a regulatory asset?

A19. Yes. The regulatory asset would initially include the actual net book value of the specific Belle River coal handling assets that are to be retired, and the actual net book value of the entire Monroe Power Plant site, based on the most recent historical balance available when the Company files its first general rate case after receiving an order in the instant IRP case. Capital expenditures incurred at the Monroe site after the initial reclassification would be added to the regulatory asset balance subject to review in future general rate cases. A separate regulatory asset would be established for the removal and decommissioning costs related to the Belle River coal handling assets and the Monroe Power Plant site.

Q20. How would the deferred regulatory assets be recovered?

A20. The Company proposes that the asset for the NBV of the plant earn a return equal to the currently authorized overall rate of return, including debt and equity. This would be accomplished by including the regulatory assets in rate base as a working capital item and reflecting the amortization expense as part of the revenue requirement. The net book value of the plants is currently in rate base and the related depreciation expense on the gross balance is in the revenue requirement.

The proposed treatment would reduce the net plant balance and recognize a regulatory asset for an equal amount. Instead of depreciation expense on the gross plant balance, there will be amortization expense of the net plant balance.

The Company also proposes that the asset for deferred decommissioning costs earn a return equal to the currently authorized overall rate of return. The deferred decommissioning costs would be recovered through amortization expense. Actual costs incurred would be deferred / debited to the regulatory asset, and accrued amortization would be credited to the regulatory asset.

Q21. How would the annual amortization expense be determined?

A21. Please refer to Exhibit A-16. This illustration assumes a general rate case will be filed in 2024 and reflects December 31, 2024, estimated balances. (The estimated amounts and rate case timing assumptions are subject to change.) The regulatory asset balance starts with the $209 million NBV of the Belle River coal handling assets on line 1 in column (c), plus the $3.1 billion NBV of the Monroe Power Plant site in column (d) for a total regulatory asset of $3.3 billion in column (e). Annual amortization expense of the NBV is approximately $138 million, as shown on line 3, column (e). To that annual amount, I add $14 million to cover estimated decommissioning costs on line 6, column (e), to get a total amortization expense of approximately $152 million on line 7, column (e).

The computation for amortization of decommissioning costs is shown starting on line 4, with $30 million for Belle River, and $300 million for Monroe, totaling $330 million in column (e). The annual amount is $14 million shown in line 6, column (e).

Q22. How did you determine the amortization period for the regulatory assets?

A22. I propose the Belle River regulatory asset be amortized through 2036 which is when the underlying plant assets would have reached a zero net book value through normal depreciation. The Monroe regulatory asset will be amortized through 2050. This timing aligns with the Company's goal to achieve net zero carbon emissions. The calculation is shown on Exhibit A-16, starting on line 8. The end of the recovery period is shown on line 10. The amortization period assumes new base rates and recovery starting in 2025 as shown on line 11. The resulting number of years of amortization expense is January 2025 through December of the recovery period for each regulatory asset, as shown on line 12. The number of years of amortization expense and recovery will be based on the actual timing of future rate cases.

Q23. Why is it appropriate to add decommissioning costs to amortization expense?

A23. Depreciation rates are intended to recover the original cost of the plant plus the net cost to retire / decommission it. For example, if the cost of a plant is $100 and it will cost $10 to decommission it when it is removed from service, depreciation rates will be established to recover $110 over the life of the asset. At the end of the plant's life, the reserve would have an "additional" $10 to absorb the removal costs. At retirement, the gross plant of $100 would be credited, and $100 would be debited to accumulated depreciation, leaving a credit balance of $10 in the reserve to absorb the removal costs. The assets subject to this proposal are being retired before the full amount for the removal and decommissioning costs has been recovered in depreciation expense. Amortization of only the regulatory asset NBV would bring the net balance to zero with nothing left in the reserve. This would result in the original cost being recovered, but none of the removal costs. Therefore, consistent with how depreciation rates are set and applied, the amortization expense must cover the NBV plus the decommissioning costs. As actual decommissioning costs are incurred, they will be charged to the regulatory asset instead of to accumulated depreciation.

Q24. Could the Company recover the decommissioning costs through depreciation rates instead of amortization expense?

A24. No. Depreciation rates must be applied to gross plant in service. Since the assets will be retired from the books, there will be no plant balance to which a depreciation rate can be applied. Regardless of whether the expense is classified as depreciation expense or amortization expense, ultimately it will be the actual removal and decommissioning costs that get recovered.

Q25. What is the basis for the estimated decommissioning costs?

A25. The costs are based on a study performed by an outside consultant, Sargent & Lundy, in DTE Electric's depreciation Case No. U-18150, plus inflation through the retirement dates in the PCA. They are presented in round numbers in the instant case to provide the order of magnitude of the costs. The Company expects to provide an updated study before requesting specific amounts in a general rate case.

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Q26. What if actual decommissioning costs are different than the amount reflected in amortization expense?

A26. The Company will maintain accounts to reconcile the amortization of estimated decommissioning costs and the actual expenditures. If a negative (credit) balance remains in the regulatory asset account after the decommissioning work is complete and paid, the balance will be refunded to customers. If a positive (debit) balance remains, the Company proposes to recover the balance in a future rate case.

Q27. Does this conclude your direct testimony?

A27. 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

AARON WILLIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF AARON WILLIS

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

A1. My name is Aaron Willis (he/him/his). 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 as Manager, Regulatory Economics.

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 Arts in Political Science from the University of Michigan, a Master's in Environmental Management from the Yale School of Forestry and Environmental Studies, and a Master's in Business Administration from the University of Maryland.

Q4. What work experience do you have?

A4. In 2009, I was employed by the US Army Corps of Engineers, Institute for Water Resources as Social Scientist. In this role I supported enforcement of the Clean Water Act and engagement with domestic and international partners on a variety of water resources issues. In 2015, I was employed by Booz Allen Hamilton in their energy practice, providing support to commercial and federal clients on a variety of energy matters including market strategies, project development, and new energy technologies. In 2017, I began my employment with DTE Energy as an Associate in Corporate Strategy. In this role I supported key operational and strategic work across the Company. I was promoted to Senior Associate in 2019 and transitioned to Corporate Development, where I supported the Company's financial strategy. In

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2020, I accepted a position in Regulatory Affairs supporting the Company's state regulatory strategy and engagement with the Commission, Staff, and Michigan energy stakeholders. In 2021, I was promoted to my current position of Manager, Regulatory Economics.

Q5. What are your current duties and responsibilities with DTE Electric?

A5. My responsibilities include the management of regulatory activities relative to DTE Electric's rate strategy, pricing, and load research.

Q6. Have you been involved in prior cases before the Michigan Public Service Commission (MPSC or Commission)?

A6. Yes. I have supported the Company's positions in Case Nos.:

- U-21163 – DTE Electric XL-High Load Factor Rate D13
- U-20836 – DTE Electric 2022 General Rate Case
- U-21306 – DTE Electric Rider No. 16 transition

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Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. My testimony will provide an estimate of the impact on average customer rates resulting from the Proposed Course of Action (PCA) as required pursuant to the Michigan Public Service Commission's December 20, 2017 order in Case No. U-18461 (Attachment A, page 22), Public Act (PA) 286 6t (5)(l). This includes an analysis of rate impacts for the Residential, Commercial Secondary, Primary, and Other classes consistent with the Commission's February 20, 2020 Order[1] in Case No. U-20471.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes. I am sponsoring the following exhibit:

Exhibit	**Description**
A-17	Average Impact on Customer Rates

Q9. Was this exhibit prepared by you or under your direction?

A9. Yes, it was.

Q10. How will the revenue requirement associated with the PCA as identified by Company Witness Manning be recovered?

A10. The revenue requirement associated with the Company's PCA will be recovered in DTE Electric's future general rate cases, related Energy Waste Reduction and Renewable Energy Program proceedings, and Power Supply Cost Recovery filings.

[1] https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000009jWc2AAE (page 87), accessed October 21, 2022

Q11. What information is presented in Exhibit A-17?

A11. Exhibit A-17 demonstrates the total impact of the Company's PCA on customer rates, described separately for Residential, Secondary, Primary, and Other. As I discuss below, this exhibit uses data from various exhibits sponsored by other Company witnesses to determine the average rate impact of the PCA.

Q12. Would you please describe how you calculated the overall average rate impact of the PCA for bundled customers in Exhibit A-17?

A12. Yes, I will describe each line and the source where applicable. The page for each customer class is structured the same. Line 1 shows the Company's current base rate revenue requirement for full-service customers, as approved by the Commission on May 8, 2020 in Case No. U-20561. Line 2 forecasts revenue requirement growth based on an inflation factor and without the impacts of the PCA. Line 4 reflects the percentage of production cost allocations assignable to the class, consistent with the May 2020 Order in Case No. U-20561. Line 6 represents the incremental revenue requirement of the PCA as supported by Company Witness Manning in Exhibit A-3.5. Line 8 is the class allocation of the incremental revenue requirement, which is the product of multiplying Line 4 and Line 6. Line 10 is the class sales forecast as supported by Company Witness Leuker in Exhibit A-10.3. Line 12 is the current average rate based on the final Order in Case No. U-20561. Line 13 is the projected rate after inflation without the impacts of the PCA. Line 14 is the absolute rate impact of the PCA. Line 15 is the relative rate impact of the PCA expressed as the absolute increase divided by the initial rate for a given year, Line 14 divided by Line 13. Line 16 is the total projected rate. Line 18 is the compound annual growth rate (CAGR) of the incremental revenue requirement in each respective class.

Q13. How does your exhibit reflect the rate impact resulting from the level of Energy Waste Reduction (EWR) in the PCA, as supported by Witness Bilyeu?

A13. The incremental revenue requirement on Line 2 includes the total incremental cost of the PCA and the EWR levels within the PCA. The incremental revenue requirement is consistent with the EWR levels assumed in Witness Leuker's sales forecast. Both the PCA and the sales forecast reflect a 2% level in 2023 and the 2021 Michigan Energy Waste Reduction Statewide Potential Study thereafter.

Q14. What is the average rate impact on bundled customers of the PCA's incremental revenue requirement on a cent per kilowatt-hour basis?

A14. For each year included in this exhibit, the amount by which rates would increase or decrease on a per kilowatt-hour basis as a result of the PCA's incremental revenue requirement for the respective year is shown on Line 14 of Exhibit A-17, Pages 1-4. The sales forecast used for this analysis is equal to Witness Leuker's bundled sales forecast for the Starting Point Scenario, shown in Exhibit A-10.3. This analysis assumes no other changes in the Company's revenue requirement over the years included in this exhibit. Below is a simplified table reflecting 2023 average impacts by class in cents per kilowatt hour, a summary of the total impact over the first five years, and the CAGR, as described in Exhibit A-17[2].

[2] Table values may vary slightly from Exhibit due to rounding

Line No.

Table 1 2023 Average Impacts by Customer Class

	Projected rate without PCA (¢/kWh)	Projected impact of PCA (2023) (¢/kWh)	Total projected rate (2023) (¢/kWh)	CAGR of PCA (%)
Residential	17.49	(0.00)	17.49	(1.74%)
Secondary	13.09	(0.01)	13.08	(2.20%)
Primary	8.25	(0.00)	8.25	(3.43%)
Other	33.79	(0.00)	33.79	(0.52%)

Considering the ranges by customer class, the incremental impact of the PCA is:

- Residential – a high of 2.76% in 2035, a low of (6.00%) in 2039, and an average change over the first five years of 0.66%
- Secondary – a high of 3.36% in 2035, a low of (7.29%) in 2039, and an average change over the first five years of 0.80%
- Primary – a high of 4.69% in 2035, a low of (10.20%) in 2039, and an average change over the first five years of 1.12%
- Other – a high of 0.93% in 2035, a low of (2.02%) in 2039, and an average change over the first five years of 0.22%

As shown by Exhibit A-17, Line 8, the annual change in revenue requirement varies over time, but over the study period the CAGR of the incremental revenue requirement of the PCA compared to the base plan is (2.18%) assuming a Year 0 value of the Case No. U-20561 approved revenue requirement.

Line No.

Q15. Does the incremental revenue requirement on Line 8 of Exhibit A-17, Pages 1-4, include all expected changes in revenue requirements during the reflected timeframe?

A15. No, it does not. The incremental revenue requirement on Line 8 is limited to the change in revenue requirement from comparing the base plan to the PCA as supported by Company Witness Manning. It is intended to isolate the revenue requirement between these two situations. 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. DTE Electric's revenue requirement will also have changed by the first full year of the IRP planning period, so I have used the currently in effect Case No. U-20561 and a standard growth rate as a proxy for projected rates.

Q16. Does this conclude your direct testimony?

A16. 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, and for other relief) Case No. U-21193

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. (he/him/his). 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. Please review your employment history with DTE Energy.

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

Line
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and reporting activities. During this assignment, I developed a working knowledge 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.

Q5. Please describe your more recent positions and duties.

A5. 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.

Q6. What are your duties and responsibilities in your current position?

A6. 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 the strategy development related to environmental compliance for the Company.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes, I have sponsored direct and/or rebuttal testimony in the following MPSC cases:

U-17319	2014 Power Supply Cost Recovery (PSCR) Plan Case
U-17680	2015 PSCR Plan Case
U-17767	DTE Electric Main Rate Case
U-17920	2016 PSCR Plan Case
U-17920-R	2016 PSCR Reconciliation Case
U-18143	2017 PSCR Plan Case
U-18403	2018 PSCR Plan Case
U-18419	DTE Electric Certificates of Necessity (CON)
U-20069	2017 PSCR Reconciliation Case
U-20221	2019 PSCR Plan Case
U-20222	2019 PSCR Reconciliation Case
U-20471	DTE Electric Integrated Resource Plan (IRP)
U-20527	2020 PSCR Plan Case
U-20528	2020 PSCR Reconciliation Case
U-20826	2021 PSCR Plan Case
U-20827	2021 PSCR Reconciliation Case
U-21050	2022 PSCR Plan Case
U-21051	2022 PSCR Reconciliation Case
U-21259	2023 PSCR Plan Case

Line No.

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. 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 Protections 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.

Q9. Did you provide inputs to the group responsible for conducting DTE Electric's IRP process for the PCA?

A9. Yes. I provided information on environmental regulations that are expected to impact the Company. Information on the impacts of environmental regulations

Line No.

were used by the Company's IRP group in the IRP planning process and associated testimony.

Q10. Are you supporting any exhibits?

A10. Yes. I sponsor the emission projections summary data provided in Exhibit A-18. I also sponsor the environmental details provided in the IRP Report.

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

Q12. How is your testimony organized?

A12. My testimony consists of the following sections:

Part I	Environmental Regulations and Compliance Options
Part II	Emissions Projections and Comparison
Part III	Environmental Justice Assessment
Part IV	Impact Assessment

PART I: ENVIRONMENTAL REGULATIONS AND COMPLIANCE OPTIONS

Q13. What are the environmental regulations impacting the Company's existing power plants?

A13. Although many environmental regulations are 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:

Line No.

- Steam Electric 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

Q14. What are the Effluent Limitation Guidelines (ELGs)?

A14. 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 economically achievable for an industry. EPA promulgated the Steam Electric Power Generating (SEPG) ELGs in 1974, and amended the regulations in 1977, 1978, 1980, 1982, 2015, and 2020. The regulations cover wastewater discharges from power plants operated by utilities. The ELGs are incorporated into National Pollutant Discharge Elimination System (NPDES) permits.

Q15. Can you describe the recent revisions to EPA's ELGs?

A15. The EPA's ELGs regulate how electric utilities must manage certain wastewaters. On October 13, 2020, the EPA finalized the ELG Reconsideration Rule which revised some requirements from the 2015 version of the ELG rule. The Reconsideration Rule revised 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 provides additional compliance opportunities by finalizing subcategories, such as for the cessation of coal burning activities.

Q16. When does DTE Electric need to comply with the revised ELGs?

A16. The Reconsideration Rule provides opportunities for the Company to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in a 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. For facilities pursuing the FGD wastewater Voluntary Incentives Program (VIP), 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 the State of Michigan.

Q17. What were DTE Electric's options for ELG compliance?

A17. The Company had two options to achieve compliance under the Reconsideration Rule for BATW and FGD wastewater. The first option was to design and engineer new technologies that are compliant with the ELG requirements for BATW and FGD wastewater. The second option was to pursue a compliance subcategory for BATW and FGD wastewater that EPA established within the Reconsideration Rule. One compliance subcategory allowed for companies to attain compliance with the ELGs for both BATW and FGD wastewater by ceasing coal burning activities, which includes retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies certified that unit(s) will cease the use of coal by unit(s) retiring or refueling, they can continue to operate those units until their specified coal retirement date, which is required to be before December 31, 2028. For the electrical generating unit(s) that certified under this subcategory, companies need to maintain the existing standard discharge limits already in effect for BATW and FGD wastewater discharges.

In addition to the cessation of coal burning activities subcategory, the Reconsideration Rule also provided a compliance subcategory specific to FGD wastewater. The Reconsideration Rule established Best Available Technology (BAT) standard discharge limits for FGD wastewater discharges and finalized the VIP subcategory. Under the VIP, companies may choose to meet more stringent effluent limits established by EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chose the VIP option, the applicability date for FGD wastewater compliance would be extended to December 31, 2028.

To establish compliance for either of the subcategories detailed previously, companies were required to submit a Notice of Planned Participation (NOPP) to the state permitting agency by October 13, 2021. DTE Electric submitted the NOPP(s) to the Department of Environment, Great Lakes, and Energy (EGLE) in Michigan on that date. Once submitted, companies are required to submit annual progress reports to EGLE to ensure the commitment of compliance under the subcategories.

Q18. Can you describe the NOPP filing requirements and any filings made by the Company?

A18. To establish compliance for the compliance subcategories detailed above, companies were required to submit an NOPP no later than October 13, 2021. The cessation of coal NOPP requirements included: (1) identification of the electric generating unit (EGU) intended to achieve permanent cessation of coal combustion; (2) expected date that each EGU is projected to achieve permanent cessation of coal combustion; (3) whether each date represents a retirement or a fuel conversion; (4) whether each retirement or fuel conversion has been approved by a regulatory body; and (5) identification of the relevant regulatory body. In addition, the NOPP must include a copy of the most recent IRP for which the applicable state agency approved the retirement or repowering of the unit subject to the ELGs, certification of EGU cessation under the CCR rule, or other documentation supporting that the EGU will permanently cease the combustion of coal by December 31, 2028. The NOPP needed to include, for each such EGU, a timeline to achieve the permanent cessation of coal combustion. Each timeline was required to include interim milestones and the projected dates of completion. A cessation of coal NOPP was submitted for Belle River Power Plant (Belle River) on October 13, 2021.

The VIP NOPP for FGD wastewater requirements included: (1) identification of the facility opting to comply with the VIP discharge requirements; (2) specify what technology or technologies are projected to be used to comply with those requirements; and (3) provide a detailed engineering dependency chart and accompanying narrative demonstrating when and how the system(s) and any

Line No.

accompanying disposal requirements will be achieved by December 31, 2028. A VIP NOPP was submitted for Monroe Power Plant (Monroe) on October 13, 2021.

Q19. What is the Company's compliance strategy for Belle River?

A19. At Belle River, fly ash is currently dry managed and therefore there are no implications with the requirements of the ELGs for fly ash treatment water (FATW). Additionally, the power plant was constructed and operates without FGDs, therefore, there is no FGD wastewater. However, the bottom ash is currently collected using transport water and the ELG Reconsideration Rule requires the Company to achieve compliance with BATW discharge requirements. As mentioned, the Company submitted an NOPP for cessation of coal at Belle River and the evaluation of an alternative fuel source. As outlined in the PCA for this case, the Company is proposing to convert Belle River to natural gas between 2025 and 2026. As a result of this conversion, and the previously submitted NOPP, the plant is utilizing a subcategory in the rule for ELG compliance by ceasing coal operation. The Company will avoid approximately $55 million in capital spend to build a new, ELG-compliant bottom ash handing system as stated in Witness Morren's testimony.

Q20. What is the Company's compliance strategy for Monroe?

A20. At Monroe, the Company is currently implementing projects for FATW ELG compliance according to the 2015 ELG Rule that will allow the plant to continue operating beyond 2023. FATW is regulated by the 2015 version of the ELG rule which requires system upgrades to be completed no later than December 31, 2023. Monroe did not have the infrastructure required to reliably comply with the 2015

ELG mandate related to fly ash in order to maintain environmental compliance. Therefore, in 2016 DTE Electric moved forward with a FATW compliance project that entailed design and engineering, procurement, demolition of existing system, and construction of a new fully automatic vacuum-to-pressure fly ash handling system. The project is currently scheduled to be completed by the end of 2023. Upon completion, Monroe's fly ash transport and storage system will be in compliance with the ELG requirements for zero-liquid discharge and be able to reliably remove 100% percent of the fly ash it produces in a dry capacity. The new system will have adequate storage and loadout capabilities to continue to operate for the remaining life expectancy of the Plant. Following installation, there will be a start-up and optimization period to get the equipment operating reliably and consistently to meet ELG standards by December 31, 2023.

For BATW wastewater ELG compliance, the Company will achieve compliance at Monroe by the end of 2025. The Company plans to terminate the use of water for bottom ash at Monroe. In place of water conveyance, a submerged grinder conveyor system will be installed. The project is currently approved for engineering, design, and initial work.

Plans for compliance with the FGD wastewater ELG have changed with the PCA proposed in this case. As mentioned above, the Company submitted an NOPP for the VIP at Monroe. The PCA includes the retirement of Units 3 and 4 at Monroe in 2028. This will significantly reduce the amount of FGD wastewater generated at the plant and will decrease the compliance costs for the plant. Although the specific technology for compliance has not been finalized, it is expected that through the early retirements of Units 3 and 4, the Company will avoid approximately $21 million in capital spend for FGD wastewater compliance. The capital spend for FGD wastewater compliance for four units at the plant was projected to be $127 million, while the capital spend for the remaining two units outlined in the PCA is projected to be $106 million. Details on expenditures required to comply with ELG regulations at Monroe can be found in Table 1 later in my testimony.

Coal Combustion Residuals

Q21. Can you describe the EPA's Coal Combustion Residuals (CCR) Rule and its impact on the Company's coal-fired units?

A21. The EPA's CCR Rule regulates how electric utilities must manage and dispose of CCR in landfills and impoundments. On August 28, 2020, the EPA published an amendment to the CCR rule (the Part A Rule) that requires all unlined surface impoundments to cease receipt of waste and initiate closure as soon as technically feasible but no later than April 11, 2021. The Part A Rule also provided utilities the ability to request site-specific alternative closure deadlines through a demonstration process to obtain EPA approval. On November 12, 2020, EPA published an additional amendment to the CCR rule (the Part B Rule) that allows 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 Rule and Part B Rule require EPA approval to continue operating the company's unlined CCR surface impoundments.

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Q22. Can you describe the Company's strategy for compliance with the amended closure provisions of the CCR Rule?

A22. The Company submitted Part B Rule applications to perform Alternate Liner Demonstrations for the Monroe Fly Ash Basin (FAB), the BRPP Bottom Ash Basins (BAB), and the BRPP Diversion Basin. The EPA is currently reviewing the submittals and the outcome of their review will determine the timeline for closure of these unlined surface impoundments. The Company is currently closing the Monroe BAB by removal of all ash. Closure of the Monroe BAB was initiated and is anticipated to be completed in accordance with the timeline required by the CCR rule. Closure is required to be complete within five years (with the opportunity for five 2-year extensions, if necessary). Compliance costs for closure of the of the ash basins mentioned above are not impacted by the early retirements proposed in the PCA in this case.

The Company's coal ash landfills – Range Road Landfill, Monroe CCR Landfill, and Sibley Quarry Landfill – have adequate capacity to manage all CCR that requires disposal, through the active life of the power plants. These landfills will be closed in place by installing cover material over the ash deposits at the end of their active life. The Company is currently making infrastructure improvements at Sibley Quarry Landfill to enhance storage capability, including the ability to accept the CCR material coming from the Monroe Bottom Ash Basin. There is not expected to be a significant reduction in compliance costs for closure of the Company's coal ash landfills due to the early retirements proposed by the PCA in this case, however savings of approximately $7 million are projected for the closures of Sibley Quarry and the Monroe CCR landfill as a result.

Q23. What information is being presented in this case related to CCR expenses and projects for the Company's CCR units?

A23. Details on capital expenditures required to comply with CCR regulations at the Company's facilities can be found in Table 1 later in my testimony. In addition to capital expenditures required to comply with the CCR regulations, there is ongoing operations & maintenance (O&M) required for compliance through inspections, monitoring, reporting, and requirements of the regulations. O&M expenditures for the Company's seven CCR units will be incurred once the units have been closed. Those seven sites include the Belle River and Monroe BABs, the Belle River Diversion Basin, the Monroe FAB, and the Range Road, Monroe CCR, and Sibley Quarry Landfills. Beyond the date of each site closure, O&M costs include ongoing monitoring and site preservation, in addition to O&M costs for remediation that are accounted for in environmental reserve accounts. The Company has one environmental reserve associated with CCR expenses at Belle River. The environmental reserve for Range Road Landfill is for groundwater remediation required by Part 115 of the Natural Resources and Environmental Protection Act of 1994, as amended. The groundwater is managed through an EGLE approved Remedial Action Plan that includes operation and maintenance of two French drain systems to capture off-site shallow groundwater to the northwest, northeast, and east of the landfill.

<u>National Ambient Air Quality Standards</u>

Q24. Can you describe the NAAQS regulations and their impact on the Company?

A24. 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.

Although all NAAQS can affect DTE Electric's power plants, two in particular have impacted the Company's generation fleet. In 2010, the EPA lowered the one-hour SO_2 NAAQS, resulting in an area in southern Wayne County being designated as non-attainment in 2013. This area included the Company's River Rouge and Trenton Channel Power Plants. The Company implemented SO_2 emission reductions at both power plants to help achieve attainment in the area through unit retirements and accepting lower emission limits. Parts of a State Implementation Plan (SIP) submitted by EGLE were disapproved by EPA, and EPA recently finalized a Federal Implementation Plan (FIP) for the area. The retirements of River Rouge and Trenton Channel in 2021 and 2022, respectively, means that no further action in this area for the Company.

The same 2010 SO_2 NAAQS that affected the Wayne County plants also impacted a small portion of St. Clair County. An area of St. Clair County that includes Belle River and St. Clair Power Plant was designated as non-attainment in late 2016. The

Company installed SO_2 monitors near the power plants to monitor actual SO_2 emissions. Using this data, and the retirement of St. Clair in 2022, EGLE submitted a Clean Data Determination (CDD) to EPA, which was subsequently approved. The CDD demonstrates that ambient air quality in the area shows attainment with the SO_2 NAAQS standard. While the CDD approval doesn't automatically redesignate the area to attainment, no further action was required regarding emissions reductions at the Company's plants. In addition, the Company has accepted lower permitted SO_2 emission limits at Belle River. These emission limits allow for the area to show attainment via air dispersion modeling. EGLE is currently developing a redesignation request for the area based on this modeling which will then be submitted to EPA for approval.

In 2015, the NAAQS for ozone was lowered from 75 parts per billion (ppb) to 70 ppb. As a result, a seven-county area of southeast Michigan was designated as non-attainment for ozone. This area includes many of the Company's fossil fuel-fired electric generating facilities. The nonattainment area is impacted by many other industries and factors. The Company, among other industrial sources in the area, are collaborating with EGLE to develop a SIP, as required, for ozone. The emission reductions associated with the Company's PCA include further reductions in ozone in the future 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 in the SIP.

Thermal Discharge Regulations

Q25. What are the thermal discharge regulations?

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A25. 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 of 316(a) are outlined below.

Q26. What are the impacts of the 316(a) regulations on the Company's operations?

A26. There are various impacts to the Company's facilities depending on the 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, 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 BWEC discharge also uses this outfall. The conversion of Belle River to natural gas proposed by the PCA in this case will reduce the water use by the plant as well as the associated thermal impact on the plant's water discharge on WOTUS.

Current plans for Monroe are to perform biological studies on the plant's water discharge outfall in 2024. These studies will be conducted to determine whether there is an impact on the aquatic ecosystem in the area. Once the studies are

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performed, any requirements related to 316(a) will be included in the plant's NPDES permit. The proposed retirement of Units 3 and 4 in 2028 included in the PCA in this case will reduce the thermal impact on the plant's water discharge on the associated WOTUS. Beyond the cost of the biological studies at Monroe, additional costs associated with 316(a) regulations, if any, are unknown at this time.

Cooling Water Intake Structure (CWIS) Regulations

Q27. What are the cooling water intake structure (CWIS) regulations?

A27. 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.

Q28. What are the impacts of the 316(b) regulations on the Company's operations?

A28. There are no expected impacts at Fermi 2 due to the use of a closed-cycle cooling system at the plant. Current plans are that Greenwood will 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 use once-through cooling systems, which entails taking in non-contact cooling water, then discharging it back to the body of water with no recirculation. The CWIS are equipped with screens that prevent debris from being taken into the plant systems. The impact of 316(b) at Belle River is expected to be minimal based on the cooling water intake design. Additionally, the natural gas conversion of Belle River proposed by the PCA in this case would reduce the water intake need at the plant and the associated impact.

The Company's expectation is that Monroe will be required to install new cooling water intake screens and install a fish return system to comply with 316(b) regulations. Through the early retirements of Units 3 and 4 proposed by the PCA in this case, the Company will avoid approximately $24 million in capital spend for 316(b) compliance. The capital spend for 316(b) compliance for all four units at the plant was projected to be $81 million, while the capital spend for the two remaining units outlined in the PCA is $57 million. 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. Details on capital expenditures required to comply with 316(b) regulations at the Monroe can be found in Table 1 later in my testimony.

Greenhouse Gas Regulations

Q29. Can you discuss the current status of Federal carbon dioxide (CO_2) and greenhouse gas (GHG) regulations?

A29. In August 2015, the EPA finalized new source performance standards (NSPS) for existing power plants under Section 111(d) of the CAA and for new sources under Section 111(b) of the CAA as part of the Clean Power Plan (CPP). The rules

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underwent significant legal challenges, and the existing source rule was stayed by a 2016 U.S. Supreme Court decision, pending judicial review. In 2017, an Executive Order was issued, which instructed the EPA to review the final rules. On October 16, 2017, the EPA published a proposal to repeal the CPP in the Federal Register. The standards for new sources under Section 111(b) were not part of the stay and remained in effect.

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) Rule as a replacement for the previously proposed CPP rule for existing sources, which never went into effect. The final ACE rule was published on June 19, 2019. On January 19, 2021, the D.C. Circuit Court vacated the ACE rule and remanded to the EPA for further proceedings. EPA issued a memorandum on February 12, 2021 regarding the status of ACE and CPP indicating that they did not expect states to take any further action to develop and submit plans under 111(d) with respect to GHG emissions. On October 29, 2021, the U.S. Supreme Court (SCOTUS) agreed to hear an appeal of the D.C. Circuit Court decision vacating the ACE rule.

SCOTUS issued an opinion on June 30, 2022, holding that EPA lacked authority under Section 111 of the Clean Air Act to set an emission cap for GHGs based on generation shifting. The SCOTUS decision also remanded the case for further proceedings. While this case continues and the ultimate outcome is uncertain, the Company has no plans to amend its current goal to achieve net zero emissions by 2050. The Company is also announcing new CO_2 reduction targets through the PCA in this case. Although there are currently no regulations for reducing CO_2 emissions from electric generating units, neither are there currently any federal

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taxes or fees associated with CO_2 emissions, CO_2 emission adders were included in some modeling sensitivities as outlined in Witness Manning's testimony.

Other Environmental Regulations

Q30. Are there other environmental regulations that the Company has considered, but do not have a large impact on the Company's IRP planning?

A30. 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 Protection Act (NEPA)
- Michigan Environmental Protection Act (MEPA)

Q31. 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?

A31. 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. 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[1] – 2023 and Beyond

Project	Estimated Cost
ELG – Monroe Fly Ash	$37M
ELG – Monroe Bottom Ash	$78M
ELG – Monroe FGD	$106M
ELG – Belle River Bottom Ash	--
CCR – Monroe BAB	$49M
CCR – Monroe FAB	$201M
CCR – Monroe CCR Landfill	$27M
CCR – Belle River Ash Basins	$20M
CCR – Range Road Landfill	$14M
CCR – Sibley Quarry Landfill	$33M
316(b) – Monroe CWIS	$57M
Total	$622M

PART II – EMISSIONS PROJECTIONS AND COMPARISON

Q32. Has the Company projected emissions for the Company's generating units for the portfolios outlined in this filing?

A32. Yes. As outlined in Witness Manning's testimony, the Company modeled five portfolios in this IRP as follows:

[1] Retire Monroe Units 3 & 4 in 2028; retire Monroe Units 1 & 2 in 2035; Belle River natural gas conversion in 2025/2026; Belle River retirement by 2039; Refer to Witness Morren for additional detail on the costs

- 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
- Portfolio 5[2]: reasonable alternatives to the PCA presented by the Company in the BAU scenario

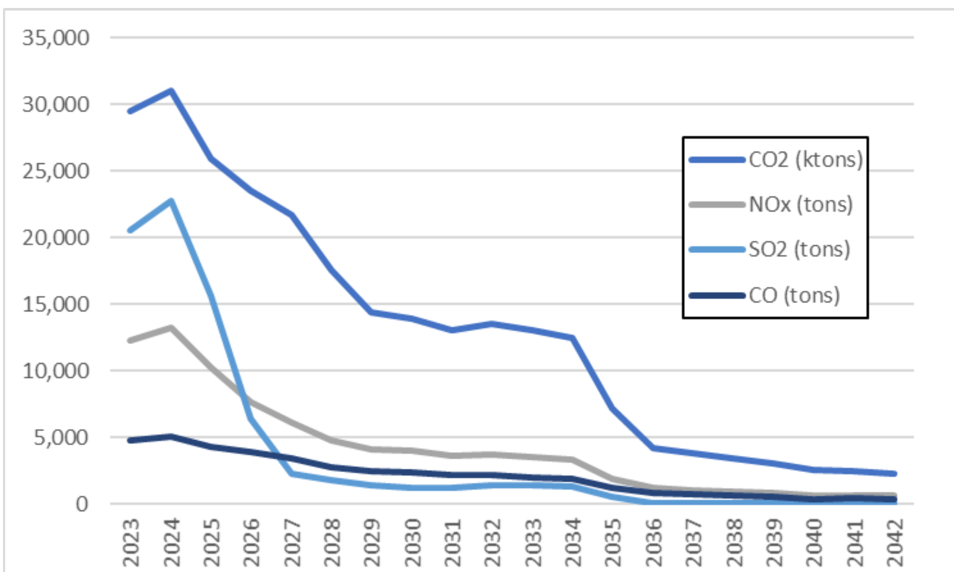
Emissions projections have been made for each of the portfolios presented in this case, including the PCA. Annual emissions projections from the IRP modeling for carbon dioxide (CO_2), carbon monoxide (CO), lead (Pb), mercury (Hg), nitrogen oxides (NOx), particulate matter (PM), sulfur dioxide (SO_2), and volatile organic carbon (VOC) were made on a unit- or facility-level and can be found in Witness Manning's workpapers and workpaper BJM-1. 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-18 Emissions Projections Summary for emissions data for the five portfolios.

Q33. Can you summarize forecasted emissions based on the PCA run in the BAU scenario?

[2] Portfolio 5 includes Belle River retiring in 2028 and two units at Monroe in 2032 with the second two in 2035.

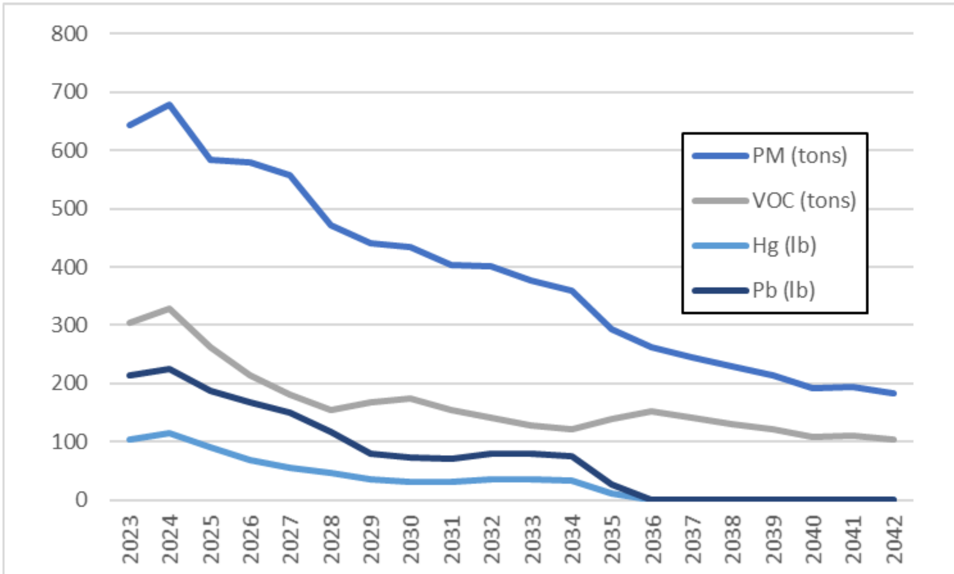
A33. Yes. While the results of the portfolios are different, the modeling performed shows that portfolios 2 through 5 allow for the Company to meet its CO_2 reduction goals. There are two major differences in the PCA of this IRP versus the Company's 2019 IRP that further reduces emissions from the Company's plants. The proposed changes in operation and retirement dates for Belle River and Monroe in this IRP significantly reduce the projected life-cycle emissions for the plants. 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 below.

Figure 1 – PCA CO_2, NOx, SO_2, and CO Emissions Trend[3]



[3] Emissions in Figure 1 and Figure 2 are shown for the fleet

Figure 2 – PCA PM, VOC, Hg, and Pb Emissions Trend

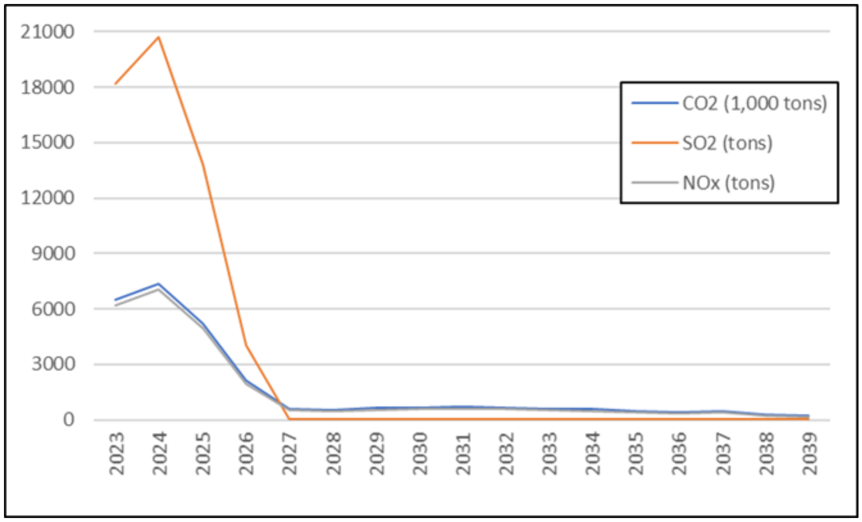


The IRP model emissions projections for Portfolio 2 do not project regular operation for the Company's diesel generation (DG) peakers. As stated in Witness Morren's testimony, peakers are valued for their capacity and ability to startup quickly and reliably in response to high peak demand or system reliability issues. In addition, peakers provide support to the distribution system. As stated in Witness Musonera's testimony, peakers provide voltage support as well as support system restoration to the distribution grid. While the peakers are necessary for system support, the IRP model cannot predict such cases and does not predict these run times or associated emissions.

Q34. Can you describe the major differences from the PCA in this case from the 2019 PCA and compare the projected emissions?

A34. Yes. The proposed changes in operation and retirement dates for Belle River and Monroe in this IRP are meaningful changes from the previous IRP which have a major impact on emissions. The PCA in this case projects emissions for Belle River from 2023 through the proposed retirement in 2039 (emissions from coal through natural gas conversion and emissions from natural gas after) versus the 2019 IRP which had Belle River operating on coal through 2030 with retirement after. The projected CO2 emissions from Belle River associated with the PCA in this case for the period from 2023 through 2039 are nearly 40% lower than for the same period in the PCA from the Company's 2019 IRP case. Additionally, SO2 emissions are nearly 60% lower and NOx emissions are nearly 45% lower. The reductions in emissions are caused not only by lower emissions from using natural gas versus coal, but also by the reduced utilization of the plant as a peaking resource as described in Witness Morren's testimony. Figure 3 below shows the emissions trend for Belle River based on the natural gas conversion. A summary of emissions can be found in Table 2 below.

Figure 3 – BRPP Emissions (2025-26 Natural Gas Conversion)



The PCA in this case proposes the retirement of Units 3 and 4 at Monroe in 2028 and the retirement of Units 1 and 2 in 2035. This provides noteworthy reductions in emissions versus the Company's previous PCA from the 2019 IRP which projected Monroe to retire in 2039. CO_2 emissions from Monroe associated with this IRP are projected to be nearly 50% lower, while SO_2 emissions are more than 65% lower, and NOx emissions are more than 50% lower for compared to Portfolio 1.

Overall CO_2 emissions are projected to be nearly 40% lower than the projections in Portfolio 1. Similar, significant reductions of emissions of other pollutants are also projected. PCA model runs (Portfolio 2) for this case were used to summarize PCA emissions in the table.

Table 2 – Emissions Reduction Summary[4]

Pollutant	2023-2039 Emissions (tons, CO_2 million tons)					
	Belle River		Monroe		Total	
	PCA	Portfolio 1	PCA	Portfolio 1	PCA	Portfolio 1
CO_2	29.0	48.3	142	273	171	321
SO_2	56,543	135,909	20,802	37,563	77,344	173,472
NOx	26,663	46,080	40,070	76,658	66,732	122,738

Q35. Are emissions from the sale and/or purchase of power accounted for in the Company's planning?

A35. Yes. Emissions from purchased power were calculated for the PCA. Similar to the 2019 IRP filing, the Company is using the net short approach of CO_2 accounting to better account for the CO_2 emissions associated only with our customers' energy needs. This method uses an adjustment from fleet direct emissions, including purchased power emissions, to estimate the total CO_2 that is attributable to energy that our customers use. The Company has continued to use this method in calculating annual emissions. While this accounting is not currently required, the Company believes this is a more accurate representation of the carbon intensity of the overall delivered electricity and also gives the customers a more accurate assessment of their full carbon footprint. For more information on CO_2 accounting, refer to Witness Mikulan's testimony.

[4] A summary of the emissions for the PCA in this case is included in workpaper BJM-1. A summary of some of the emissions reductions compared to the Portfolio 1 are shown in Table 2 below. Detailed emissions data can be found in Witness Manning's workpapers and workpaper BJM-1.

In addition, the Company has projected other pollutant emissions from the amount of power purchased in the future. The Company used generation projections from the PCA to calculate these emissions. Emission factors from the EPA's Emissions and Generation Resource Integrated Database (eGRID) were used where available. The Company also used internally developed emission factors for some pollutants. Regional emission rate changes over time are not predictable and the methodology used to calculate emission and emissions projections will be updated in future IRPs. A summary of the emissions projected from purchased power is shown in Table 3 below and details can be found in workpaper BJM-1.

Table 3 – Annual Emissions from Purchased Power (PCA)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CO2 (tons)	997,270	828,297	1,064,872	1,435,267	1,212,640	2,999,586	2,134,508	1,903,494	1,428,379	1,673,979
NOx (tons)	491	441	462	499	346	780	465	405	268	324
SO2 (tons)	823	759	703	416	127	298	157	125	92	121
PM (tons)	26	23	26	38	32	77	50	44	30	35
CO (tons)	192	169	191	254	197	446	277	243	160	190
VOC (tons)	12	11	12	14	10	25	19	18	11	12
Hg (pounds)	4	4	4	4	3	8	4	3	2	3
Pb (pounds)	9	8	8	11	9	19	9	7	5	7
	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CO2 (tons)	1,139,732	1,604,703	812,404	555,360	384,033	463,248	380,279	256,412	183,741	180,438
NOx (tons)	204	281	78	32	20	22	16	8	6	6
SO2 (tons)	80	109	20	1	1	1	1	1	0.4	0.4
PM (tons)	22	30	12	7	5	5	4	2	2	2
CO (tons)	118	162	48	21	13	14	10	5	4	3
VOC (tons)	8	10	6	4	3	3	2	1	1	1
Hg (pounds)	2	3	0.5	0	0	0	0	0	0	0
Pb (pounds)	5	6	1	0	0	0	0	0	0	0

Q36. 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?

A36. 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 to customers. The Company's plan based in the 2019 IRP was 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 this case will reduce 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.

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 CO_2 emissions by 2050 fits within the range of pathways consistent with what is outlined in these reports.

<u>PART III – ENVIRONMENTAL JUSTICE ASSESSMENT</u>

Q37. Can you describe the Company's environmental justice (EJ) analysis purpose and approach?

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A37. 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. Detailed emissions data and calculations can be found in Witness Manning's workpapers and workpaper BJM-1.

Q38. Did the Company perform an Environmental Justice (EJ) screening?

A38. Yes. The Company used the EPA Environmental Justice Screening and Mapping Tool (EJSCREEN) Version 2.0 to perform an EJ screening. All fossil fuel-fired generating facilities were included in the screening. The goal of the screening was to identify vulnerable communities located within a 3-mile radius of each facility, which was determined in consultation with EGLE and MPSC Staff. Vulnerable communities were identified as having an EJ index at or above the 80th percentile[5].

[5] 80th percentile, EPA, https://www.epa.gov/ejscreen/frequent-questions-about-ejscreen#q5, accessed October 19, 2022

Each facility was mapped using EJSCREEN. A summary of the EJSCREEN data is included in workpaper BJM-2.

Q39. What were the results of the EJ screening?

A39. Using EJSCREEN, four of the Company's facilities were identified as having at least one environmental index at or above the 80th percentile within a 3-mile radius of the facility. The facilities with at least one EJSCREEN environmental index at or above the 80th percentile are Delray Peakers (DEL), Northeast Peakers (NE), River Rouge Power Plant Peakers (RRP; River Rouge Power Plant retired), and Superior Peakers (SUP). A summary of environmental indexes for those facilities with at least one environmental index at or above the 80th percentile in EJSCREEN is included in Table 4 below.

Table 4 – Environmental Index Summary for Facilities with at Least One Environmental Index at or Above the 80th Percentile

Index	DEL	NE	RRP	SUP
PM 2.5	95	89	94	81
Ozone	94	89	93	81
2017 Diesel PM	96	91	95	82
2017 Air Toxics Cancer Risk	95	90	95	81
2017 Air Toxics Respiratory	95	89	94	81
Traffic Proximity	96	91	94	82
Lead Paint	96	92	95	78
Superfund Proximity	91	89	92	78

RMP Facility Proximity	98	97	99	77
Hazardous Waste Proximity	98	93	97	89
Underground Storage Tanks	97	94	96	85
Wastewater Discharge	96	71	96	94

The EPA EJSCREEN tool does not have a composite environmental index that combines other indexes to determine a more wholistic percentile for a given site. With this in mind, other sites were assessed as to whether there was a reasonable potential that the surrounding area could be above the 80th percentile under a composite index, depending on the methodology used to develop a composite index. Taking this into consideration and based on the data shown in workpaper BJM-2, Dearborn Energy Center and Monroe were included in the EJ analysis.

Q40. How does the Company's PCA impact the areas associated with the EJ analysis that was performed?

A40. As mentioned, the EJSCREEN tool was used in the analysis. While the EJSCREEN is a screening tool to identify environmental index values for a given area, it is not a method to compare the various portfolios for EJ impact within the screening. However, the various portfolios can be qualitatively assessed to compare the impacts of the portfolios. For example, continuing to operate Belle River on coal as planned in the previous PCA versus converting to natural gas would increase emissions, water use, water discharge, and ash generation. Similarly, operating Monroe longer than the dates proposed in the PCA in this case would have similar increases. Although Belle River and Monroe are not located in areas identified as vulnerable by the EPA EJSCREEN tool, the associated PCA emissions reductions, water impact reductions, and waste generation reduction do reduce the overall impact in the area.

As stated, 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. Water use will be reduced significantly by the conversion to natural gas at Belle River and the early retirements at Monroe. The natural gas conversion and future operation proposed by the PCA in this case at Belle River will reduce water used for electric generation at the plant by 60% which will reduce the Company's water use by 10% overall as shown in workpaper BJM-3. 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 decrease the water discharge from the facilities, including thermal discharge reductions. Blue Water Energy Center uses some water for cooling, but more than 90% less than what Belle River currently uses operating on coal. The Company's peakers and other remaining units do not use water for operation.

Waste generated at Belle River and Monroe will also decrease significantly with the conversion of Belle River to natural gas and early retirements of the Monroe units. This includes bottom ash, fly ash, and other wastes. The generation of bottom ash and fly ash will be eliminated at Belle River 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 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 the four sites identified as having an environmental index at or above the 80th percentile are all either peaker sites or have peakers, in the case of RRPP. As discussed in Witness Morren's testimony, the Company performed a peaker analysis which was considered in the Company's IRP modeling. The results of this analysis are included in Witness Morren's testimony. The peakers located at the RRPP site are being evaluated for retirement with transmission studies underway by MISO as discussed by Witness Roy. Retirement of the peakers at the RRPP site would have further positive impact on the area. The retirement of Northeast peaker 11-1 as outlined in Witness Morren's testimony will also have a positive impact on the areas identified.

PART IV – IMPACT ASSESSMENT

Q41. Did the Company perform a health impact assessment?

A41. Yes. The Company used the EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) Web Edition (https://cobra.epa.gov) to determine the health impact estimates for the air emissions reductions proposed by 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" and the optional subsector was chosen as "coal" since the major reductions in the Company's PCA are coal retirements. The model has entry fields for emissions data for $PM_{2.5}$, SO_2, NO_x, ammonia (NH_3), and VOC. For this case, NH_3 was not one of the pollutants identified in discussions with EGLE and the Company did not calculate emissions for NH_3, so that field was left blank when running the COBRA model. Emissions projections of 2023 and 2042 were used to evaluate the impacts for the assessment. County-level impacts were assessed for Wayne, St. Clair, Monroe, Macomb, Oakland, and Washtenaw Counties.

Q42. What were the results of the health impact assessment performed using the COBRA model?

A42. The COBRA model summarizes impacts for change in incidence (cases, annual) and monetary value (dollars, annual) for 12 health endpoints. A low and high value are provided for mortality and non-fatal heart attacks endpoints. The assessment of health impacts using the COBRA tool showed an overall benefit for all portfolios. A summary of the results of the health impact assessment using the COBRA model based on the PCA is provided in Table 5 below. Further detail on the data from the assessment for other portfolios and county-level data can be found in workpaper BJM-4. The low value is used in the table for those endpoints for which low and high values are provided by the COBRA model.

Table 5 – Summary of COBRA Health Impact Assessment – State-Level

Health Endpoint	Change in Incidence (Reduction)	Monetary Value
Mortality	9.8	$95,700,000
Nonfatal Heart Attacks	0.98	$145,842
Infant Mortality	0.05	$586,448
Hospital Admits, All Respiratory	1.9	$103,304
Hospital Admits, Cardiovascular (except heart attacks)	2.0	$71,843
Acute Bronchitis	10.8	$6,639
Upper Respiratory Symptoms	195	$8,317
Lower Respiratory Symptoms	137	$3,695
E.R. Visits, Asthma	4.4	$2,484
Asthma Exacerbation	204	$15,124
Minor Restricted Activity Days	5,841	$512,073
Work Loss Days	983	$196,744
Total Monetary Value		$97,352,519

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

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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. Results are presented in 2017 dollars.

Q43. Can you describe the PM2.5 impact assessment performed by the Company and the results based on the PCA?

A43. Yes. As can be seen in the emissions projections provided in Witness Manning's workpapers and workpaper BJM-1, there is a decrease in emissions over the course of the PCA. As such, the impacts of PM2.5 will also decrease over time, including within the areas near facilities identified as having an EJ environmental index above the 80th 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. As can be seen in the referenced workpapers, PM emissions decrease by greater than 40% by 2033, greater than 60% by 2037, and greater than 70% by 2042 based on the PCA. This is in addition to the emissions reduction from power plants that the Company has already retired.

Q44. Can you describe the impact assessment on NAAQS non-attainment areas performed by the Company and the results based on the PCA?

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No.

A44. Yes. The PCA was used to assess the impact on areas in which Company 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. As discussed previously, no further action is required by the Company for the Wayne County SO_2 nonattainment area and the reduced emission limits that the Company permitted for Belle River (operating on coal) allows for the St. Clair County SO_2 nonattainment to achieve attainment. The further emission reductions at BRPP proposed by the PCA with the conversion of the plant to a natural gas peaking resource in this case strengthen the SO_2 attainment status of St. Clair County. While the seven-county ozone nonattainment area in southeast Michigan is impacted by industries and factors beyond the Company, the emissions reductions projected by the PCA in this case will provide benefit to the status of the area related to ozone NAAQS by providing further reduction in NO_x and VOCs. 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.

Q45. Does this complete your 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, and for other relief	)	Case No. U-21193

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ADELLA F. CROZIER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF ADELLA F. CROZIER

Q1. Please state your name, business address and by whom you are employed.

A1. My name is Adella F. Crozier (she/her/hers). My business address is One Energy Plaza, Detroit, MI 48226. I am employed by DTE Energy Corporate Services LLC, a subsidiary of DTE Energy Company (DTE Energy), within Regulatory Affairs as a Director.

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 education background?

A3. I received a Bachelor of Science degree in Metallurgical Engineering from Iowa State University and a Master of Business Administration degree from the University of Chicago. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q4. What work experience do you have?

A4. Prior to my employment at DTE Energy, I was employed by LTV Steel Company (LTV) in various roles including Metallurgical and Quality Control Engineer in positions of increasing responsibility for different product lines. My last role with LTV was as Product Manager in the Sales and Marketing Department. In this role, I had responsibility for managing the relationship between the Sales and Marketing Department and one of LTV's major plants. As part of my responsibilities, I ran financial and engineering analyses related to product line offerings.

Q5. What has been your work experience at DTE Energy?

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A5. I joined DTE Energy in 2003 as a Technological Specialist in the Fossil Generation Department's Engineering Support Organization. In 2004, I was promoted to Supervisor – Mechanics and Metallurgy. In 2005, I joined the Regulatory Affairs Department as Manager of Special Projects. In this role, I assisted the Environmental Affairs Department with their portions of Detroit Edison's general rate case filings and served as a member of several workgroups related to Governor Granholm's 21st Century Energy Plan and Capacity Need Forum. I helped with the Company's implementation of Michigan's 2008 energy legislation, particularly those areas related to energy optimization. I managed several Detroit Edison energy optimization filings as well as provided witness testimony regarding the revenue requirement of several energy optimization plans and reconciliations. During this time, I also assisted the case managers of general rate cases.

I was promoted to Manager of Electric Regulatory Strategy in 2013 where my responsibilities included research of regulatory matters. My team provided management of DTE Electric's general rate cases.

I was promoted to Director within Regulatory Affairs in 2016. In this role, my team is currently responsible for managing the Company's state filings and activities at the Michigan Public Service Commission (MPSC or Commission). Members of my team also provide various research activities pertinent to our electric utility and provide cost of service and revenue requirement modeling.

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

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No.

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

U-15806	Detroit Edison's Energy Optimization (EO) Plan
U-15806 A	Detroit Edison's EO Amended Plan
U-16358	Detroit Edison's 2009 EO Reconciliation
U-16359	Detroit Edison's 2010 EO Reconciliation
U-16737	Detroit Edison's 2011 EO Reconciliation
U-20561	DTE Electric 2019 Rate Case
U-18232	DTE Electric 2020 Renewable Energy Plan (REP) Amendment
U-18091	DTE Electric 2021 PURPA Avoided Costs
U-20836	DTE Electric 2021 Rate Case

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Purpose of Testimony

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

A7. The purpose of my testimony is to:

- Describe the Company's position relative to determining the existence of a capacity need in the context of administering the Public Utilities Regulatory Policy Act of 1978 ("PURPA")

Q8. Are you sponsoring any exhibits in this proceeding?

A8. No, I am not.

CAPACITY DEMONSTRATION

Q9. How does the Company propose that generation capacity need be demonstrated relative to the administration of PURPA?

A9. The Company's need to procure capacity is identified through periodic integrated resource plan (IRP) proceedings as well as annual capacity demonstration filings. Therefore, the Company proposes that generation capacity need continue to be evaluated in periodic IRP proceedings and additionally informed by the Company's annual capacity demonstration filings.

Q10. Why is the Company proposing that generation capacity need be evaluated in IRP proceedings?

A10. Statutory IRP proceedings are the most reasonable vehicle for evaluating the Company's capacity position because such proceedings entail a comprehensive review of the Company's electric generation resource needs, available generation resources and proposed incremental supply- and demand-side resources, if identified.

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Reliability and operating characteristics of the various available technologies are considered when identifying the most reasonable and prudent plan. Generation characteristics related to capacity, energy production, and dispatchability are also considered. In addition, the IRP process considers the role and performance of demand-side options such as energy waste reduction, demand response, and conservation voltage reduction/volt var optimization.

Q11. What specifically did the Commission last definitively determine as the Company's capacity need?

A11. The Commission's September 26, 2019 order in Case No. U-18091, the most recent PURPA order establishing the Company's avoided costs, determined that the Company did not have a capacity need over the five-year planning horizon adopted in that case. At that time, the fifth year of the planning horizon was Midcontinent Independent System Operator (MISO) planning year 2024 which covers June 1, 2024 to May 31, 2025.

Q12. When does the Company plan to file its next avoided cost case?

A12. DTE Electric was engaged in extended proceedings involving consideration of PURPA policy, DTE Electric's avoided costs, and DTE Electric's capacity need from 2016 through 2022 in Case No. U-18091. In light of a Commission Order issued on July 7, 2022 in that proceeding the Company anticipates that its next MCL 460.6v and/or PURPA proceeding will be initiated six months after completion of this IRP proceeding and that the status quo with respect to matters involving MCL 460.6v and/or PURPA (including the determination that DTE Electric has no present capacity need) will remain in effect until issuance of a final Commission Order in that new MCL 460.6v and/or PURPA proceeding.

Q13. What is the Company's current capacity position as reflected in this IRP filing?

A13. The Company has included an updated view of its current capacity position in this IRP filing which is supported by Witness Manning, and is reflected on Exhibit A-3.3. As reflected on Exhibit A-3.3, the Company does not have a material long-term need for generation capacity beginning in any year of the five-year planning horizon.

Q14. What has the Company assumed regarding the renewal of existing PURPA contracts?

A14. Witness Burgdorf states in his testimony that the Company assumes that the current power purchase agreements (PPAs), including PURPA contracts, will be renewed and continue as resources throughout the entire IRP time-period. This assumption has been made as a result of the July 31, 2017 Commission Order in Case No. U-18091 requiring such:

> "The Commission also finds that existing QFs with expiring contracts should have their contracts renewed at the full avoided cost rate, whether or not the company forecasts a capacity shortfall over the planning horizon."

In addition, the Commission adopted the current Michigan Integrated Resource Planning Parameters in the November 21, 2017 Order in Case No. U-18418 requiring three of the four scenarios in an integrated resource planning filing to assume that QF contracts are renewed up to the utility's "must buy" obligation MW threshold unless the QF indicates otherwise either publicly or directly to the utility.

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Q15. Does the Company agree with the Commission's determination to automatically renew existing PURPA contracts once they reach their expiration date?

A15. No. There is no reasoned basis to provide a guaranteed capacity payment to existing QFs seeking new PPAs after expiration of the existing power purchase agreement with an electric utility. Such a provision is clearly inconsistent with the statutory avoided cost rate cap in PURPA section 210(b) that customers of electric utilities not be required to subsidize QFs. This provision potentially obligates the utility to contract with a QF for capacity it does not need while also inserting the Commission's judgement into a contract to which it is not a party.

Q16. Why is a determination of the duration of the capacity need and the utility's likely means of fulfilling that need key to informing a utility's PURPA obligations?

A16. If the Company has a capacity need that requires capacity to be built to meet its Planning Reserve Margin Requirement (PRMR) or requires the utility to enter into a long-term contract for capacity that signals a capacity need that could likely be avoided, or partially offset by contracting with a QF. Absent such a need, there is no new generation capacity or long-term purchase contract to defer, and therefore no avoided cost associated with such deferral. DTE Electric would not build new physical generation capacity to meet minimal short-term capacity shortfalls, nor would DTE Electric sign a long-term capacity contract to meet such a need. More expedient and efficient ways exist to meet capacity shortfalls of this nature, including short-term bilateral purchases and enrollment of additional demand response customers. Assuming that the Company would invest in new generation capacity or enter into long-term PPAs in order to meet non-existent or minimal intermittent capacity shortfalls is therefore not appropriate in the context of determining a capacity need under PURPA. Again, this would violate the requirement that the Company, and therefore its customers, not pay more to the QF than it would have paid if the Company would have self-generated or purchased the power, absent the QF.

Q17. What are the proper criteria to determine whether a utility has a capacity need that should be available for potential QF contracts?

A17. A capacity need that the Company could avoid by executing a long-term contract with a QF must 1) be a projected shortfall in the utility's ability to demonstrate resource adequacy to MISO that spans multiple consecutive years, and 2) represent avoidable generation capacity with the primary objective of addressing that shortfall. Any short duration or intermittent capacity need within the relevant planning horizon should not be viewed as a capacity need that would obligate the Company to a long-term contract. Such short-term or intermittent capacity needs would most likely represent an avoidable purchase based on short-term options such as a bilateral contract for capacity or zonal resource credits. Furthermore, capacity that is obtained for state mandated renewable portfolio standard (RPS) compliance or voluntary green pricing (VGP) programs should not be determined to be a capacity need under PURPA as I will discuss later in my testimony.

Q18. Does the Company still believe a five-year planning horizon as established by the September 26, 2019 order is the most appropriate time frame for evaluating capacity needs relative to PURPA?

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No.

A18. 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 PSCR plan forecast which is filed annually, and 3) the State requirement in Public Act 341 section 6v (1) relative to the Commission conducting contested proceedings for reviewing PURPA avoided costs.

Q19. Why are planning horizons beyond five years not appropriate?

A19. Capacity additions beyond the next five years should not be considered when determining capacity need under PURPA. Forecasts more than five years out are subject to significant uncertainties including: technology cost, efficiency, availability uncertainties, as well as the uncertainties related to changes in peak demand and usage. Thus, expanding the time horizon for quantifying an explicit capacity need beyond five years unnecessarily increases risk for DTE Electric's financial commitments, and thus retail electric customer rates. These risks are exacerbated by the current inflationary and supply chain volatility being experienced. Potential capacity needs that may occur further than five years out can be addressed in subsequent IRP and PURPA proceedings or additional filings to update critical assumptions. As the Commission noted in its September 26, 2019 Order:

> *"…the changing energy landscape means that utilities who once nearly exclusively built large, fossil-fuel baseload units to meet a capacity need are now evolving towards a more incremental and diverse generation fleet that can be built more quickly and with less planning time than a traditional base-load coal plant. As such, a five-year*

> *planning horizon is better suited to keep pace with a quickly evolving energy landscape."*[1]

Q20. Earlier, you stated that renewable generation built to meet renewable energy compliance is not a capacity need. What is your rationale?

A20. Adding resources to meet renewable energy compliance, either state-mandated or customer driven, does not constitute a capacity need. These investments are driven by the requirement to meet a percentage of the Company's *energy* needs with renewable sources or by Company customers voluntarily seeking to source their energy from renewables. Neither of these investments are driven by capacity needs. In addition, PURPA contracts cannot be relied upon to avoid the need to purchase from other resources to meet renewable compliance obligations because PURPA contracts do not require the conveyance of renewable energy credits (RECs) to the contracting electric utility; the Federal Energy Regulatory Commission (FERC) has determined that RECs generated by a PURPA QF do not necessarily accrue to the host electric utility unless explicitly provided by state law, which is not the case in Michigan. Thus, PURPA contracts cannot be expected to defer these renewable investments by DTE Electric. Note that the Company is willing to explore the purchase of RECs from operating QFs in the future pursuant to renewable energy filings if doing so proves economical but purchasing RECs does not constitute a capacity need under PURPA.

Q21. Should renewable generation built to meet voluntary green pricing programs be considered a capacity need?

[1] Case No. U-18091 Order dated September 26, 2019, p. 56

Line No.

A21. No. Similar to renewable generation built to meet renewable energy mandates, renewable generation built to support voluntary green pricing tariffs should not be construed as a capacity need. These investments are driven by a subset of our customers who are interested in sourcing a higher share of their energy needs from renewables. In addition, a significant portion of these renewable additions are tied to agreements between DTE Electric and large retail electric customers that specify terms, including pricing. If the Company did not offer these legislated programs which are voluntary for our customers, the renewable resources would not be built and thus these investments are not avoided costs in the context of PURPA.

Q22. What earlier determinations has the Commission made regarding how generation built for compliance with the state's mandated RPS and VGP programs should be treated relative to evaluating the Company's capacity need?

A22. The Commission recognized in its September 26, 2019 Order, that the fact that a utility intends to build generation to meet its RPS requirement does not mean that the utility has a capacity need:

> *"Intervenors in the present case pointed to the company's planned addition of renewable generation to meet its RPS compliance requirements pursuant to MCL 460.1028 as evidence that the company has an existing capacity need. However, the Commission does not agree. … Thus, the RPS compliance requirement is not designed to fill a capacity need."*[2]

[2]Case No. U-18091 Order dated September 26, 2019, p. 46

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Also, the Commission acknowledged in its February 20, 2020 interim order in the Company's IRP, at page 27, that the "*impetus for these REP and VGP renewable resources is not a capacity need*" even though those resources will serve load.

Q23. Does this complete your direct testimony?

A23. 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, and for other relief	))))	Case No. U-21193

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

ESTELLA R. BRANSON states that on November 3, 2022, she served a copy of DTE Electric Company's Application, Protective Order, Nondisclosure Certificates, Testimony and Exhibits of Witnesses, Joyce E. Leslie, Laura K. Mikulan, Shayla D. Manning, Rodrigo Cejas Goyanes, Kevin Carden, Justin L. Morren, Keegan O. Farrell, Kevin L. Bilyeu, Vielka M. Hernandez, Markus B. Leuker, Shawn D. Burgdorf, Sonjoy D. Roy, Grace N. Musonera, Ryan C. Pratt, Timothy J. Lepczyk, Theresa M. Uzenski, Aaron Willis, Barry J. Marietta and Adella F. Crozier in the above captioned matter, via electronic mail upon the persons listed on the attached service list.

Estella R. Branson Digitally signed by Estella R. Branson Date: 2022.11.03 13:10:56 -04'00'

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