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

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July 19, 2024

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

RE: In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Act 295 of 2008, as amended.
MPSC Case No. U-21662

Dear Ms. Felice:

Attached for electronic filing in the above referenced matter is DTE Electric Company's Application, DTE Electric Company's Application, Direct Testimony and Exhibits of Witnesses, Kevin L. Bilyeu, Patrick D. Kauffman, Frank M. Kopinski, Kirk M. Vangilder, Sherri L. Wisniewski, Emily C. Meloche, Eddie Smith, and Nathan D. Bennett. Also attached is the Proof of Service.

Very truly yours,

John A. Janiszewski

Digitally signed by John A. Janiszewski
Date: 2024.07.19 13:52:59 -04'00'

John A. Janiszewski

JAJ/cdm
Attachments

cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Act 295 of 2008, as amended.	)	Case No. U-21662

APPLICATION

DTE Electric Company ("DTE Electric" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") approve its Amended Renewable Energy Plan ("REP") and related relief, pursuant to 2008 Public Act (PA) 295, as amended by 2023 PA 235, MCL 460.1001 *et seq*., the Rules of Practice and Procedure Before the Michigan Public Service Commission, R 460.17101 *et seq*., the Michigan Administrative Procedures Act, MCL 24.201 *et seq.*, and all other applicable law, and find the Company's Amended REP reasonable, prudent, and consistent with all applicable requirements. In support of the relief requested in this Application, DTE Electric states as follows:

1. DTE Electric is a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at One Energy Plaza, Detroit, Michigan 48226. DTE Electric is owned by DTE Electric Holdings, LLC, which is a wholly-owned subsidiary of DTE Energy, providing retail electric service to customers located in Michigan.

2. DTE Electric's retail electric business is subject to the Commission's jurisdiction pursuant to Michigan law, including certain provisions of 1939 PA 3, as amended, MCL 460.1 *et seq*.; 1909 PA 106, as amended, MCL 460.551 *et seq*.; 1909 PA 300, as amended, MCL 462.2 *et*

seq.; and 2008 PA 295, as amended by 2023 PA 235, MCL 460.1001 *et seq*. Under these statutory provisions, the Commission has the power and jurisdiction to regulate the Company's retail electric rates.

3. This Application is being filed in accordance with the Commission's Orders dated February 8, 2024, April 25, 2024, and May 23, 2024 in Case No. U-21568, *In the matter, on the Commission's own motion, to implement the provisions of Sections 22 through 49 and related definitions of Public Act 235 of 2023*.

4. On October 6, 2008, the "Clean, Renewable, and Efficient Energy Act," 2008 PA 295 ("Act 295"), MCL 460.1001 *et seq*., was signed into law. Act 295 was amended by 2016 PA 342 ("Act 342") effective April 20, 2017, and was renamed the "Clean and Renewable Energy and Energy Waste Reduction Act."

5. On November 28, 2023, Public Act 235 of 2023 ("Act 235") was signed into law and became effective on February 27, 2024. Among other things, Act 235 further amended Sections 22 through 49 of Act 295 to increase the Renewable Portfolio Standards ("RPS") for electric providers from 15% through 2029, to 50% in years 2030 through 2034, and 60% in 2035 and thereafter.

6. Section 22(3) of Act 235, MCL 460.1022(3), requires electric providers to file with the Commission their respective amended REPs within one year of the effective date of Act 235. On February 8, 2024, the Commission issued an Order in Case No. U-21568 requiring DTE Electric to file its Amended REP under Act 235 no later than July 19, 2024. Section 22(3) of Act 235, MCL 460.1022(3), requires the Commission to issue a final order in amended REP proceedings within 300 days after the date of filing with the Commission.

7. DTE Electric's currently applicable REP was approved by the Commission in Case No. U-21361 on May 18, 2023. The Company's current REP was based on the best knowledge and information about renewable energy markets and project operations as of early 2023, before the enactment of Act 235.

8. DTE Electric has worked diligently to develop a workable and economic Amended REP which runs through 2045 and is designed to achieve the requirements of Act 235. Pursuant to Act 235, the Company's Amended REP includes proposed updates to renewable energy targets of 50% in 2030 through 2034, and 60% in 2035 and each year thereafter. The Company's Amended REP includes reasonable and prudent costs regarding both the incremental cost of compliance and Power Supply Cost Recovery ("PSCR") Transfer Prices, as well as reasonable and prudent REP surcharges, all of which properly address the requirements of Act 235.

9. Consistent with Act 295, as amended by Act 235, DTE Electric's Amended REP describes, among other things: (a) how DTE Electric will address RPS targets consistent with Section 28 of Act 235, MCL 460.1028, and how the Amended REP aligns with the Company's approved 2022 Integrated Resource Plan ("IRP") in Case No. U-21193; (b) whether the number of megawatt-hours ("MWh") of electricity used in the calculation of the Renewable Energy Credit ("REC") portfolio will be weather-normalized or based on the average number of MWh of electricity sold by the Company annually during the previous three years to retail customers in Michigan pursuant to Section 28 of Act 235, MCL 460.1028; (c) the expected incremental cost of compliance for a 20-year period consistent with Section 45 of Act 235, MCL 460.1045; (d) the bidding process to be used by the Company pursuant to Section 28(6) of Act 235, MCL 460.1028(6); (e) considerations regarding the need for a volumetric revenue recovery mechanism for the recovery of the incremental costs of compliance consistent with Section 22(2) of Act 235,

MCL 460.1022(2); (f) why the Amended REP is reasonable and prudent under Section 22(5) of Act 235, MCL 460.1022(5), taking into consideration projected costs, and why the Amended REP is consistent with the purpose and goals set forth in Section 1(2) of Act 235, MCL 460.1001(2), and meets the applicable RPS targets through 2045.

10. The renewable energy build plan that was recently approved in the Company's 2022 IRP in Case No. U-21193 aligns with the assumptions in this Amended REP and achieves the RPS targets established in Act 235.[1] Cost assumptions for projects in this Amended REP are not intended to displace cost parameters established in the Company's approved IRP Settlement Agreement in Case No. U-21193. Thus, the estimated costs for projects in this Amended REP are within the range of costs set forth in the IRP Settlement Agreement, which states renewable energy projects are consistent with the IRP if determined to be priced at or below fair market value by the Independent Monitor based on bids submitted in each respective Request for Proposal ("RFP") or at or below 150% of the $52.80 Solar LCOE used in the IRP model on Exhibit A-4.3 (i.e., $79.20) in Case No. U-21193. The years 2026 and 2027 reflect impacts from recent RFP results. Additionally, this Amended REP meets the ownership requirements set forth in the approved IRP Settlement Agreement.

11. Pursuant to Section 28(1) of Act 235, MCL 460.1028(1), the Amended REP includes a mechanism for recovering the incremental cost of compliance within its rates and a forecast of the renewable energy resources needed to comply with the new RPS targets. As

[1] In the April 25, 2024 Order in Case No. U-21568, pp. 19-20, the Commission stated, "IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources (including the consideration of the value of the various resource types and attributes as expressed by commenters). In turn, future amended REPs should reflect the assumptions included in the providers' most recently approved IRP".

required by Section 45(3) of Act 235, MCL 460.1045(3), the Amended REP calculates the incremental cost of compliance for a 20-year period through 2045.

12. According to the Company's forecast, there is no need for a revenue recovery mechanism surcharge through 2028. The Company will continue to recover the transfer price revenue through the PSCR through 2028, as permitted by Section 47(3) of Act 235, MCL 460.1047(3), and consistent with its currently approved REP in Case No. U-21361. In reliance on Section 22(3) of Act 235, MCL 460.1022(3), the Company intends to file its next amended REP no later than the second quarter of 2027 with an order required by the first quarter of 2028. Several factors may change over time that impact whether a surcharge will be necessary to recover the incremental cost of compliance, including, but not limited to, variations from the Company's long-term energy production forecasts, operating cost forecasts, third party PPA charges or revenues. Therefore, the Company will address the need for a revenue recovery mechanism surcharge, if needed, in its next amended REP filing or an REP reconciliation, as permitted by Act 235.

13. The Company is requesting certain accounting authority along with other regulatory approvals to effectuate its Amended REP. DTE Electric plans to create an accumulation of reserve funds and carry forward a regulatory liability. The Company had previously set REP surcharges with the intent to recover the cost of the plan and build an accumulation of reserve funds in advance of plan expenditures which creates a regulatory liability. The running balance of the regulatory liability is variable based on the assumptions used. DTE Electric will reconcile to the plan, and if the balance forecast projects a negative balance, resulting in a regulatory asset, the Company will provide updated assumptions and/or implement a surcharge, if necessary. This approach is consistent with the Commission's April 25, 2024 Order in Case No. U-21568, which

held that any regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings as is the current practice.

14. The costs associated with the Amended REP, including execution of DTE Electric's renewable energy build plan, are influenced by numerous factors that could either raise or lower the Company's implementation costs between now and 2045. The renewable energy build plan and its related costs will be revised every two years in the Company's subsequent amended REP filings, in accordance with Act 235.

15. DTE Electric's Amended REP takes into consideration and utilizes the Company's approved transfer price schedules for the Company's Act 295, as amended by Act 342, renewable energy contracts and Company-owned renewable energy system that run through 2029. Furthermore, DTE Electric is requesting approval of the Company's transfer price schedules that extend previous transfer price schedules through 2045 in accordance with Act 235.

16. DTE Electric is requesting approval of the projected renewable energy generation expense for the Company for years 2024 through 2045 which will be transferred for recovery through the Company's PSCR mechanism, for renewable energy contracts and Company-owned renewable energy systems that will be used to comply with Act 235.

17. The Amended REP includes the Company's current electric sales forecast for the period 2024-2045 and support thereof, as well as customer count projections for the period 2024-2045.

18. DTE Electric is requesting approval of the Amended REP's revenue requirement in Exhibit A-23, interest on regulatory liabilities in Exhibit A-24, and pre-tax rate of return and revenue conversion factors in Exhibit A-25.

19. The Company is requesting approval of the reasonableness and prudence of deferred taxes, tax regulatory assets and liabilities, and property tax expense in the Amended REP, as primarily reflected in Exhibit A-27. The average balance of deferred tax assets and liabilities and tax regulatory assets and liabilities shown on Exhibit A-27, line 39 is reflected as a reduction in rate base in Exhibit A-9, line 11 for Compliance assets and line 20 for Authorized Large Customer Voluntary Green Pricing ("VGP") program assets. Property tax expense is a component of revenue requirements as shown in Exhibit A-23, line 20.

20. The Amended REP assumes projects will achieve the maximum federal Production Tax Credits ("PTC") and Investment Tax Credits ("ITC") allowed based on their timing. Only one type of tax credit, PTC or ITC, was chosen when there are different alternatives for the same resource. The benefits of PTCs and ITCs are shown in Exhibit A-22.

21. The Amended REP accrues an Allowance for Funds Used During Construction ("AFUDC") for renewable assets under construction. DTE Electric received approval in Renewable Energy Plan Accounting Application Case No. U-21496 to accrue an AFUDC during development on construction work in progress for renewable energy projects within the Company's REP. The AFUDC rate includes DTE Electric's renewable energy plan's most recently approved rate of return, which will be updated when new renewable energy plan rates of return are determined.

22. DTE Electric's Amended REP includes updates to the Company's VGP program under MCL 460.1061, including its MIGreenPower Demand forecast and a request to increase the build plan for the MIGreenPower program.

23. DTE Electric included the assets for its VGP program approved in Case No. U-21361 in the Amended REP. Subscribed portions of the assets attributable to VGP have been

subtracted from the REP and the revenue from those subscriptions. Revenue from the subscribed assets is shown in the incremental cost of compliance as one of the costs recovered to offset the revenue requirement. These costs are calculated based on the actual or projected subscription fee for the VGP program.

24. The Company proposes inclusion of additional assets attributable to its VGP program in its Amended REP. DTE Electric is proposing additional solar builds of 300 MW for 2027, 500 MW for 2028, and 130 MW for 2029. These additions are aimed at meeting customer demand within the VGP program. According to Section 9 of the Settlement Agreement in the Company's Section 61 filing Case No. U-21172, projects selected through the RFP process to fulfill VGP demand will be distributed proportionately between VGP Program customers and non-participating customers. The goal of this allocation is to achieve cost parity between participating and non-participating VGP program customers.

25. Subscribed portions of the VGP programs do not count toward the Company's RPS targets. Subscribed portions of the VGP programs are incremental to the REP and the associated RECs are retired on behalf of subscribers. Consistent with Section 28(2)(b) of Act 235, MCL 460.1028(2)(b), the amount of sales attributable to customers participating in a VGP program is subtracted from the total amount needed for compliance with the RPS.

26. A projection of the RECs that the Company will either self-generate or receive from third party renewable energy systems is provided in Exhibit A-4. The RECs from the Company's self-generation and the Company's Michigan Incentive RECs will be booked at zero value. The RECs used in the Company's VGP programs are not included in Exhibit A-4 since the Company retires RECs on behalf of customers for subscribed portions of the MIGreenPower program.

27. DTE Electric's Amended REP includes a plan to pursue energy storage resources co-located with renewable facilities that may be included for recovery in a subsequent amended REP filing. The Company would recover the fixed cost of co-located storage resources through the PSCR Transfer Price mechanism.

28. The Company proposes the inclusion of its cost-share for a long duration energy storage ("LDES") demonstration project at the Pine River wind park and solar array, which will be partially funded through a Department of Energy ("DOE") grant under the Infrastructure Investment and Jobs Act ("IIJA"). Inclusion of such costs is conditional on the Company's successful negotiation of an award from the DOE.

29. This Application is being filed with the supporting Direct Testimony and Exhibits of eight (8) witnesses (Mr. Kevin L. Bilyeu, Mr. Patrick D. Kauffman, Ms. Sherri L. Wisniewski, Mr. Kirk M. Vangilder, Mr. Frank M. Kopinski, Ms. Emily C. Meloche, Mr. Eddie Smith, and Mr. Nathan D. Bennett). The contents, recommendations, revenue and expense items, and proposed ratemaking items set forth in the supporting Direct Testimony and Exhibits are fully incorporated in this Application by reference.

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

A. Accept this Application for filing;

B. Give such Notice to interested parties as may be required by statute or the Commission's rules;

C. Establish a date, time, and place for a prehearing conference;

D. Conduct a hearing on this Application to determine the Company's compliance with 2008 PA 295, as amended by 2023 PA 235, and whether its Amended Renewable Energy Plan is reasonable, prudent, and consistent with all applicable requirements;

E. Approve the Company's Amended Renewable Energy Plan and assumptions therein as compliant with 2008 PA 295, as amended by 2023 PA 235, the Commission's Orders in Case No. U-21568, and all other applicable law;

F. Approve the Company's calculated incremental cost of compliance as consistent with 2008 PA 295, as amended by 2023 PA 235, the Commission's Orders in Case No. U-21568, and all other applicable law;

G. Approve the Company's continued recovery of the transfer price revenue through the PSCR through 2028, as permitted by Section 47(3) of Act 235, MCL 460.1047(3), and consistent with its currently approved amended REP in Case No. U-21361;

H. Approve the Company's plan for a revenue recovery mechanism under Section 22 of Act 235, MCL 460.1022(2), for inclusion in the Company's tariffs to permit recovery of the incremental cost of compliance required to implement the Amended Renewable Energy Plan as consistent with 2008 PA 295, as amended by 2023 PA 235, the Commission's Orders in Case No. U-21568, and all other applicable law;

I. Approve the revenue recovery mechanism surcharge of $0.00/meter for all customer classes and authorize the Company to maintain a regulatory liability, as requested in this Application and in a manner consistent with 2008 PA 295, as amended by 2023 PA 235, through the application of the Transfer Prices requested in this filing;

J. Authorize the necessary accounting and regulatory authority to effectuate the Company's Amended Renewable Energy Plan;

K. Approve inclusion of additional solar builds of 300 MW for 2027, 500 MW for 2028, and 130 MW for 2029 attributable to the Company's VGP program in its Amended Renewable Energy Plan, and find that such inclusion is consistent with 2008 PA 295, as amended by 2023 PA 235, Section 9 of the Settlement Agreement in the Company's Section 61 filing Case No. U-21172, and all other applicable law;

L. Approve the Company's plan to pursue energy storage resources co-located with renewable facilities that may be included for recovery in a subsequent amended REP filing and recovery of the fixed cost of co-located storage resources through the PSCR Transfer Price mechanism;

M. Grant any other relief described in this Application as requested by the Company; and

N. Grant the Company such further additional relief as the Commission may deem suitable and appropriate.

DTE ELECTRIC COMPANY

Dated: July 19, 2024

By: John A. Janiszewski Digitally signed by John A. Janiszewski Date: 2024.07.19 13:53:21 -04'00'

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KEVIN L. BILYEU

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEVIN L. BILYEU

Line No.

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

A1. My name is Kevin L. Bilyeu (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (DTE Electric or Company).

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric.

Q3. What is your educational background?

A3. I graduated from Walsh College in 2008 with a Bachelor of Business Administration. In 2012, I received a Master of Business Administration degree from the University of Michigan.

Q4. What is your work experience?

A4. Starting in 2006, I began my professional career with SEMCO Energy Gas Company, progressing through a range of roles with increasing responsibility. In 2008, I took on the position of Billing Analyst, utilizing my expertise in the subject matter to aid stakeholders, conducting reviews, managing projects, and devising process enhancements. After that, I became Supervisor of Customer Accounting in 2011, leading tasks such as customer billing, remittance processing, inactive collections, bad debt management, and financial reporting for the Customer Accounting Department. Then, in 2013, I assumed the position of Manager, Customer Energy Management, where I oversaw the administration, monitoring, and development of Energy Waste Reduction (EWR) Programs, testified and

supported EWR plan and reconciliation cases at the Michigan Public Service Commission (MPSC), and managed the home protection warranty program.

In 2015, I transitioned to DTE Electric, taking on the role of Principal Marketing Analyst of EWR Pilot Programs, where my responsibilities encompassed the development and management of new EWR programs. In 2016, I accepted the position of Principal Marketing Specialist of EWR Strategy, where my tasks included modeling energy efficiency in Integrated Resource Plans (IRP) for long-term strategy planning and developing sensitivities and recommendations to support EWR plan filings with the MPSC.

In 2018, I advanced to the position of Principal Supervisor of EWR Strategy, where I had overall responsibility for strategic development and planning of EWR programs, including IRPs and EWR regulatory filings. Subsequently, in 2021, I assumed the role of Manager for EWR Strategy and Evaluation Measurement & Verification (EM&V). As Manager, I had overall responsibility for strategic development and planning of EWR programs, which included IRPs and EWR regulatory filings. Additionally, I was responsible for ensuring program cost-effectiveness, evaluating EWR programs, and applying the results to further enhance DTE Electric and DTE Gas's offerings. I accepted my current position in 2023.

Q5. What is your current position with the Company?

A5. My title is Manager, Renewable Energy Strategy and Special Projects.

Line No.

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 Renewable Portfolio Standard (RPS) compliance, planning and executing special projects for renewable energy, and filing applications with the MPSC.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A7. Yes. I have sponsored testimony in the following cases:

U-17362	SEMCO Energy Gas Company EO Plan Filing
U-18091	DTE Electric 2024 PURPA Filing
U-18419	DTE Electric Certificate of Necessity
U-20471	2019 DTE Electric Integrated Resource Plan
U-20876	2021-2022 DTE Electric EWR Plan
U-20881	2021-2022 DTE Gas EWR Plan
U-21193	2022 DTE Electric Integrated Resource Plan
U-21313	2022 DTE Electric and DTE Gas EWR Reconciliation
U-21353	2022 DTE Electric Renewable Energy Cost Reconciliation
U-21496	2023 DTE Electric Renewable Energy Plan Accounting Application
U-21550	2023 DTE Electric Renewable Energy Cost Reconciliation

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my direct testimony is to:

Line No.

1) Provide an overview of the statutory framework under 2008 Public Act 295, as amended by 2016 Public Act 342 and 2023 Public Act 235 (PA 235), and address specific policy issues as it relates to renewable energy;
2) Provide an overview of and reason why the Company is filing this Amended Renewable Energy Plan (REP);
3) Support and explain how DTE Electric's Amended REP is reasonable, prudent, and consistent with the requirements of PA 235;
4) Explain the Company's method to recover incremental cost of compliance; and
5) Introduce the other Company witnesses in this proceeding and preview their testimony.

My testimony will explain the major components and assumptions associated with the Company's Amended REP. My testimony refers to relevant information and data that may be supported by other witnesses in this proceeding.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-1	Renewable Energy Credit and Technology Overview
A-2	Renewable Energy Plan Summary
A-3	Generation from DTE Electric Renewable Energy Facilities
A-4	Forecasted Renewable Energy Credit Balance and Transactions
A-5	Assumptions for Forecasted Renewable Builds

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

Line No.

A10. Yes, they were.

Q11. Who is presenting testimony for the Company's Amended REP?

A11. The Company will present its case through seven witnesses, in addition to myself, as follows:

- **Mr. Nathan D. Bennett,** Manager – Clean Energy & Acquisitions, will summarize DTE Electric's plans for co-located energy storage with renewables.
- **Mr. Patrick D. Kauffman,** Principal Supervisor – Renewable Energy Program, will summarize DTE Electric's projected Renewable Energy capital, operation and maintenance (O&M) and other expenses associated with implementing DTE Electric's Amended REP. In addition, he will outline key accounting practices related to the Company's Amended REP including: (1) the removal of REP financial impacts from the Company's traditional base rate accounting, and (2) the accounting for and calculation of production tax credits (PTCs).
- **Mr. Frank M. Kopinski,** Engineer - Principal, Generation Optimization - Tactical Merchant Analytics, will present the Company's transfer price schedules for the Company's renewable energy contracts and Company-owned renewable energy systems and provide the projected expenses for 2024 through 2045 which will be transferred for recovery through DTE Electric's Power Supply Cost Recovery (PSCR) mechanism.
- **Ms. Emily C. Meloche,** Data Analyst, Corporate Energy Forecasting, is supporting the sales forecast and customer count projection for the period 2024-2045.

Line No.

- **Mr. Eddie Smith,** Manager – Product Development and Residential Marketing for Voluntary Renewables, is supporting the Company's voluntary green pricing (VGP) programs.
- **Mr. Kirk Vangilder,** Principal Financial Analyst, Regulatory Affairs, will present the incremental cost of compliance calculation based on the costs and renewable energy plan surcharge (a/k/a revenue recovery mechanism surcharge) revenues associated with the Company's Amended REP that were supplied to him and are supported in this application by Witnesses Kopinski, Kauffman, Wisniewski, and myself. He will also be supporting the pre-tax cost of capital that he uses to calculate the return on rate base, and the calculation of interest on regulatory liabilities.
- **Ms. Sherri Wisniewski,** Director - Taxation, is supporting the reasonableness of deferred taxes, tax regulatory assets and liabilities, and property tax expense in the Company's REP.

Q12. How is the remainder of your testimony organized?

A12. My testimony consists of the following four parts:

Part I: Statutory Framework

Part II: Amended REP Overview

Part III: Revenue Recovery Mechanism

Part IV: Other Policy Assumptions and Proposals

Part IV: Summary and Conclusions

Line No.

PART I: STATUTORY FRAMEWORK

Q13. Did recent legislation amend 2016 Public Act 342 and the associated requirements for an Amended REP?

A13. Yes, on November 28, 2023, Public Act 235 of 2023 (PA 235) was signed into law, which, among other things, amends Sections 22 through 49 of 2016 Public Act 342 to increase the Renewable Portfolio Standards (RPS) for electric providers from 15% through 2029, to 50% in years 2030 through 2034, and 60% in 2035, and thereafter.

Q14. Why is the Company filing this Amended REP?

A14. Section 22(3) of PA 235 requires electric providers to file with the Commission their respective amended REPs within one year of the effective date of PA 235. For rate-regulated electric providers, the Amended REP shall include a mechanism for recovering the incremental cost of compliance within its rates and a forecast of the renewable energy resources needed to comply with the new RPS set forth in Section 28(1). In order to allow the necessary time and attention needed to review the REPs, the Commission implemented a staggered schedule for the amended REP filings pursuant to Section 22 of PA 235 which requires DTE Electric Company to file its REP no later than July 19, 2024 (U-21568 February 8, 2024 Order, page 2).

The Company's currently approved REP was based on the Company's best knowledge and information about renewable energy markets and project operations as of early 2023, before the passing of PA 235. Pursuant to PA 235, the Company proposes the amendments included in this filing to meet the updated renewable energy targets of 50% in 2030 through 2034 and 60% in 2035 and each year

Line No.

thereafter. This amendment also calculates the incremental cost of compliance for a 20-year period, as required in Section 45(3) of PA 235.

In this section of my testimony, I will highlight the Company's current key assumptions and provide an overview of the Company's Amended REP.

Q15. What objectives were considered when developing the Amended REP?

A15. The Amended REP was designed to meet the RPS targets specified by PA 235 and program objectives. There were several key requirements:

a) Describe how DTE Electric will address the RPS consistent with Section 28 and how it is consistent with the Company's approved 2022 Integrated Resource Plan (IRP), Case No. U-21193.

b) Clarify whether the number of megawatt-hours (MWh) of electricity used in the calculation of the REC portfolio will be weather-normalized or based on the average number of MWh of electricity sold by the Company annually during the previous three years to retail customers in Michigan per Section 28.

c) Include the expected incremental cost of compliance for a 20-year period consistent with Section 45.

d) Describe the bidding process to be used by the Company per Section 28(6).

e) Consider the need for a volumetric revenue recovery mechanism for the recovery of the incremental costs of compliance consistent with Section 22(2),

f) Summarize why the plan is reasonable and prudent as required by Section 22(5), taking into consideration projected costs; and why the plan is consistent with the purpose and goal set forth in Section 1(2) and meets the RPS targets through 2045.

Line No.

Q16. What are the RPS targets established in PA 235?

A16. PA 235 establishes that an electric provider shall achieve a renewable energy credit (REC) portfolio of at least the following:

a) Through 2029, 15% of total retail sales

b) In 2030 through 2034, 50% of total retail sales

c) In 2035 and each year thereafter, 60% of total retail sales

Q17. Has the Company calculated the RECs needed to achieve the RPS targets?

A17. Yes, based on a forecast of previous year annual retail sales provided by Witness Meloche, the Company has calculated the quantity of RECs DTE Electric must obtain to comply with the REC requirements of PA 235 and provides the results on Exhibit A-2 line 16.

Q18. Has the Commission provided guidance on renewable energy build plan assumptions in an Amended REP?

A18. Yes, in the April 25, 2024 Order in Case No. U-21568, the Commission states "IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources (including the consideration of the value of the various resource types and attributes as expressed by commenters). In turn, future amended REPs should reflect the assumptions included in the providers' most recently approved IRP".

Q19. Is DTE Electric proposing to modify the renewable energy build plan recently approved in its 2022 IRP, Case No. U-21193?

Line No.

A19. No. The renewable energy build plan that was recently approved in the Company's 2022 IRP aligns with the assumptions in this instant case. The years 2026 and 2027 reflect impacts from recent Request for Proposal (RFP) results. Additionally, this Amended REP meets the ownership requirements set forth in the 2022 IRP Settlement Agreement, Case No. U-21193.

Q20. Does the renewable energy build plan recently approved in the Company's 2022 IRP meet the RPS targets in PA 235?

A20. Yes. The renewable energy build plan that was recently approved in the Company's 2022 IRP achieves the RPS targets established in PA 235.

PART II: AMENDED REP OVERVIEW

Plan Overview

Q21. What are the key components of the Company's Amended REP portfolio?

A21. The Company's Amended REP includes a portfolio adding approximately 5.7 million RECs in 2024 up to approximately 42.7 million RECs in 2045 (Exhibit A-2, lines 19-22). The renewable energy systems will be comprised of 10,391 MW of wind energy generating facilities and 9,783 MW of solar generating facilities by 2042. In comparison, the Company's currently approved REP forecasted 3,919 MW of renewable energy systems. Of the renewable energy systems, approximately 485 MW of wind and 3,152 MW of solar are allocated to the Company's current and prospective voluntary green pricing programs, a requirement of Section 61 of Public Act 342.

Q22. What time frame is covered in the Amended REP?

Line No.

A22. The exhibits supporting the Company's Amended REP reflect actual numbers through 2023; however, as of the time of this filing, the Company's 2022 REP Reconciliation Case No. U-21353 and 2023 REP Reconciliation Case No. U-21550 are pending with the Commission. Therefore, 2022 and 2023 are listed as "prelim" in the exhibits and any changes will be reflected accordingly in subsequent REP filings. From the 2023 base, the exhibits project planned information through 2045.

Q23. What is the purpose of Exhibit A-1, "Renewable Energy Credit and Technology Overview?"

A23. Exhibit A-1 is a filing requirement included in the Commission's May 23, 2024 Order in Case No. U-21568. The exhibit summarizes RECs by generation type and program type through 2045.

Q24. Do the forecasted RECs in the Company's Amended REP meet the RPS targets set forth in PA 235?

A24. Yes, as shown on lines 18-26 of Exhibit A-2, the Company expects to generate or purchase RECs that will achieve the RPS targets through 2045.

Q25. Does the Company's ability to achieve the RPS targets rely on assumptions outlined in this Amended REP?

A25. Yes, forecasted levels of generated and purchased RECs are dependent on, and sensitive to, several critical assumptions which are detailed later in my testimony. The Company's ability to comply with the RPS throughout the term of the Amended REP is dependent upon the actual performance of the renewable assets aligning with the capacity factor projections and the assumptions used in the development of this

Line No.

plan. The Company expects to be in compliance with PA 235 consistent with the provisions outlined in MCL 460.1028 by making a good faith effort to achieve the RPS and by prudently incurring incremental costs of compliance.

Q26. What technologies are considered in the Amended REP?

A26. The Company has included wind, solar, biomass, landfill gas, and hydroelectric assets. Refer to Exhibit A-1 for a summary of the technologies included in this Amended REP.

Q27. Does the Company foresee building additional renewable energy beyond that which is included in this Amended REP?

A27. At the time of this filing, the Company does not have plans to build or procure additional renewable energy beyond what is included in this Amended REP. However, if there is demand for additional renewable energy identified as a result of future IRPs, increased VGP demand, statutory compliance changes, or reduced generation from existing assets, the Company will re-evaluate the need for additional renewable energy and include it in subsequent Amended REP filings.

Q28. Did the Company calculate the forecasted incremental cost of compliance of the Amended REP?

A28. The forecasted incremental cost of compliance of the Company's Amended REP can be found in line 41 of Exhibit A-2. The incremental cost of compliance is supported by Witness Vangilder and his Exhibit A-22.

Line No.

Q29. What has changed in the utility industry since DTE Electric filed its last Amended REP filing in 2023?

A29. There are several factors that have been affecting the electric utility industry since the Company filed its last Amended REP, Case No. U-21361, in early 2023. Broadly speaking, these include: 1) state policies on climate and the environment, 2) transmission delays, 3) siting issues and 4) supply chain constraints. These factors and how the Company considered them in this instant case are discussed further below. As the electric utility industry continues to evolve and adapt to the changing environment, ongoing planning and continued collaboration will be essential.

Q30. What risks could affect the development of renewable energy systems required to meet the higher RPS targets?

A30. Several risks may impact the Company's and other developers' ability to build the necessary renewable energy systems needed to achieve higher RPS targets, including:

- **Special Use Permits:** Local opposition, community approval delays, and strict community requirements have delayed construction and increased pricing for renewable energy projects. RPS requirements and state siting discussions have increased awareness locally for the demand for renewables which has driven increased opposition.
- **Transmission Upgrades / Backfeed Delays:** Interconnection upgrades are significantly delayed due to the recent demand of renewable generation in Michigan. Projects continue to be impacted due to the delays in electrical backfeed.

Line No.

- **MISO Definitive Planning Phase Process:** The 2023-cycle queue was delayed to Q2 2024 due to the large number of projects being submitted, and the timing of the application deadline for the 2024-cycle queue is uncertain at this time. MISO has communicated its intentions to implement a queue cap in the 2024-cycle, limiting the number of projects that can be submitted.
- **Siting/Land Acquisition:** With the increased demand for renewable energy and the possibility of state siting, many developers are competing to acquire land to develop projects. In the past, developers have encountered environmental and infrastructure constraints late in the process, requiring changes to project layouts, and requiring more land, which can cause significant delays.
- **Tariff:** Multiple tariffs recently announced by the Biden administration and a new tariff petition filed by US manufacturers could impact developer's build plan and cost.

Key Assumptions

Q31. What are key assumptions within the Amended REP that, if varied, may impact the achievement of forecasted RECs?

A31. The Amended REP runs through 2045 and is based on the Company's best estimates and forecasts on a wide range of factors. The Company's REC portfolio could vary from what is depicted in Exhibit A-2 if any of the following critical assumptions prove to be materially different:

- Annual retail sales volume
- PSCR Transfer Prices
- Capacity factors
- Installed costs

- O&M costs
- Applicable property taxes
- Commercial operating dates
- Tax Credits
- Allowance for Funds Used During Construction (AFUDC)

The remainder of this section of my testimony will provide additional details on these key plan assumptions.

Q32. What sales basis is the Company using to calculate its REC portfolio?

A32. Consistent with Section 28(2)(b) of PA 235, the Company used weather normalized megawatt-hours of electricity sold during the previous year, less the amount of sales attributable to customers participating in a VGP program and the outflow from customers participating in the distributed generation program, as a basis for determining the RECs needed to satisfy the RPS targets as summarized on line 9 of Exhibit A-2. Witness Meloche discusses the sales forecast used for the period 2024-2045.

Q33. What assumptions are there regarding transfer price schedules within the Amended REP?

A33. The Company is using the 2022 transfer price schedule for all future projects, as this transfer price schedule was the most recently approved at the time of preparation of this Amended REP. The actual transfer price schedule assigned to those projects will be the most recently approved transfer price schedule at the time of the project's MPSC approval. Witness Kopinski discusses the Company's assumptions regarding

Line No.

transfer prices for the Amended REP. Line 35 of Exhibit A-2 reflects the prices at which renewable energy is assumed to be sold, and line 37 shows the amounts which would be recovered through the Company's PSCR plan and reconciliation process.

Q34. What are the Company's assumptions regarding net capacity factors within the Amended REP?

A34. For Company-owned and power purchase agreement (PPA) projects that are operational or approved at the time of this filing, the forward-looking capacity factor projections are consistent with the approved plan from the Company's prior Amended REP Case No. U-21361.

For all future solar projects, DTE Electric used its most recent approved solar investments in Case No. U-21361, which were filed on October 26, 2023, as the baseline in 2024. These include three self-developed solar projects with a 2025 commercial operation date. The Company applied a production curve based on a net capacity factor forecast from the 2023 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[1]. For solar projects, the Company uses Class 9 moderate assumptions. NREL provides solar assumptions for 10 resource categories in the United States, binned by mean global horizontal irradiance (GHI). Most of Michigan is in the <4 GHI Bin.

For all future wind projects, DTE Electric used its most recent approved wind investments in Case No. U-18232, which were filed on June 18, 2019 and April 30, 2020 as the baseline in 2024. These include two wind projects with 2021 and 2023

[1] For solar projects: https://atb.nrel.gov/electricity/2023/utility-scale_pv

Line No.

commercial operation dates. The Company applied a production curve based on a net capacity factor forecast from the 2023 NREL ATB[2]. For wind projects, the Company used NREL Class 8 moderate assumptions. 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 for wind speed in the range of 6.53 - 7.1 m/s the corresponding resource class is Class 8.

Refer to Exhibit A-5 for a summary of net capacity factor assumptions used for forecasting renewable builds.

Q35. How can deviations from the forecasted capacity factors impact the incremental cost of compliance?

A35. The actual incremental costs of compliance and creation of RECs may differ from the estimates provided in Exhibit A-2 if actual capacity factors materially deviate from those assumed in the Company's Amended REP. Variations from long-term averages, such as annual average wind speeds, can also affect REC creation and PSCR transfer price revenues in any given year. Lastly, changes in energy market prices can influence the dispatch of renewable energy systems, potentially leading to curtailment of available wind resources.

Q36. What are the Company's assumptions regarding installed costs within the Amended REP?

A36. For solar projects, DTE Electric used its most recently approved solar investments in Case No. U-21361, which were filed on October 26, 2023, as the baseline in 2024.

[2] For wind projects: https://atb.nrel.gov/electricity/2023/land-based_wind

Line No.

These include three self-developed solar projects with a 2025 commercial operation date. To forecast future costs, the Company applied a cost curve based on an installed cost forecast from the 2023 NREL ATB, along with an inflation factor.

For wind projects, DTE Electric used its most recent approved wind investments in Case No. U-18232, which were filed on June 18, 2019 and April 30, 2020, as the baseline in 2024. These include two wind projects with 2021 and 2023 commercial operation dates. To forecast future costs, the company applied a cost curve based on an installed cost forecast from the 2023 NREL ATB, along with an inflation factor.

Refer to Exhibit A-5 for a summary of installed cost assumptions used for forecasting renewable builds.

Q37. What are the Company's assumptions regarding ongoing operating and maintenance (O&M) and ongoing capital costs in the Amended REP?

A37. The Company's Amended REP includes forecasts of O&M, and ongoing capital costs. These estimates are primarily informed by DTE Electric's experience with pricing from contractors. Capital costs reflect the probability that some equipment, such as inverters for solar assets or gear boxes for wind turbines, will need to be replaced during the life of each renewable generating asset. Witness Kauffman provides more information on these O&M and ongoing capital assumptions.

Q38. What are the Company's assumptions regarding property taxes within the Amended REP?

Line No.

A38. The Company is utilizing an estimated composite property tax rate to calculate property taxes on the Company-owned renewable generating assets. Witness Wisniewski details the Company's assumptions regarding property taxes. If property taxes are higher or lower than assumed, then the Company's incremental costs of compliance would increase or decrease accordingly.

Q39. What tax credits did the Company consider in the Amended REP?

A39. The Production Tax Credit (PTC) and the Investment Tax Credit (ITC) are federal income tax credits enacted to incentivize the production of energy from and investment in renewable energy resources, respectively. The Company considered both tax credits in the Amended REP.

Q40. What are the Company's assumptions regarding the PTC and ITC federal income tax credits within the Amended REP?

A40. The Company has assumed projects will achieve the maximum tax credits allowed based on their timing. Only one type of tax credit, PTC or ITC, was chosen when there are different alternatives for the same resource. While five projects were initially assumed to select ITCs in the Amended REP, actual tax credit selection may vary based on actual project-specific data. The benefits of PTCs and ITCs are shown in Exhibit A-22 lines 10-12.

Other key assumptions include that all PTCs and ITCs generated 2023 and beyond will be transferred to a third party at a 5% discount, and those credits generated prior to 2023 will be utilized based on DTE Electric's current forecast. In addition, the benefit of ITCs that are transferred to third parties will reduce Incremental Cost of

Line No.

Compliance (ICOC) in the year generated. Key assumptions in the ITC calculation include that 95% of capital will be eligible for an ITC of 40%, which further assumes these projects will also be eligible for the Energy Community adder.

Q41. Is the Company accruing an Allowance for Funds Used During Construction (AFUDC) for renewable assets under construction?

A41. Yes. DTE Electric received approval in Renewable Energy Plan Accounting Application Case No. U-21496 to accrue an AFUDC during development on construction work in progress for renewable energy projects within the Company's REP. The AFUDC rate includes DTE Electric's renewable energy plan's most recently approved rate of return, which will be updated when new renewable energy plan rates of return are determined.

Company-Owned Renewable Energy Systems

Q42. To what extent does the Amended REP forecast RECs produced by Company-owned generating systems?

A42. Line 19 of Exhibit A-2 reflects the volumes of RECs, including incentive RECs, expected to be produced by generating assets owned by the Company.

Q43. What are the cost assumptions regarding the RECs produced by Company-owned generating assets?

A43. Revenue requirements for DTE Electric-owned generating assets are summarized on lines 28 and 31 of Exhibit A-2 and are based on the best of the Company's knowledge and experience at the time this filing was submitted to the Commission.

Witness Vangilder supports the calculation of revenue requirements, utilizing data provided by other Company witnesses.

Actual costs will result from contracts and activities implemented to engineer, procure, construct, and operate renewable energy systems. All contracts for engineering, procurement, and construction of DTE Electric-owned renewable projects will be submitted to the MPSC for approval.

Q44. What is the purpose of Exhibit A-3, "DTE Electric Owned Renewable Energy Facilities Generation?"

A44. Exhibit A-3 shows the Company's 2024-2045 projected installed capacity and generation output for DTE Electric-owned renewable energy facilities. Wind parks are shown individually on lines 2 through 59. Solar projects are shown on lines 64 through 127. Solar projects included within the Company-owned SolarCurrents program are split into two groups in order to distinguish the applicable transfer price schedule. Lines 60-63, and 128-131 reflect portions of the wind and solar parks that are projected to be subscribed through VGP programs.

Third Party Renewable Energy Systems

Q45. To what extent does the Amended REP include forecasted RECs produced from third parties?

A45. Line 20 of Exhibit A-2 reflects the volumes of RECs expected to be produced by third parties through PPAs. Line 21 of Exhibit A-2 reflects the volumes of RECs expected to be produced by third parties and purchased through REC-only contracts.

Line No.

Q46. What are the Company's assumptions regarding third-party purchases within the Company's Amended REP?

A46. The costs associated with purchases of RECs are reflected on pages 3 and 4, lines 4 and 9 of Exhibit A-4 and reflect the Company's actual price paid for contracted purchases. The REC prices from third-party renewable energy contracts will essentially be the difference between the total contract price and the PSCR transfer price. To the extent that the Company's approved transfer price as reflected in Witness Kopinski's exhibits exceeds the total contract price, the PSCR transfer price utilized will be the same as the total contract price. The RECs from REC-only contracts will reflect their actual delivered expense.

Q47. What are the Company's assumptions regarding a financial compensation mechanism (FCM) for PPAs?

A47. PA 235 introduced a FCM calculation for PPAs entered into after June 30, 2024. Consistent with Sec. 28(8) of PA 235, DTE Electric applied the pre-tax weighted average cost of capital to annual contract payments for PPAs to calculate the FCM.

Additionally, DTE Electric applied an FCM to two PPAs entered into prior to June 30, 2024: the Coldwater River and White Pine Grove projects. These projects include an FCM as approved in the Company's 2022 IRP, Case No. U-21193. The FCM is calculated as the after-tax weighted cost of capital applied to annual payments made under the applicable contracts.

Line No.

Q48. What assumptions has the Company made regarding the ownership split of Company-owned renewable energy systems and third-party renewable energy systems?

A48. The Company has assumed an ownership split through 2030 that aligns with the allocation approved in Section 12 and Section 14 of the Company's IRP Settlement Agreement in Case No. U-21193. After 2030, the Company assumes a generic ownership of projects. DTE will update ownership assumptions based on the outcome of future IRP filings.

Q49. How did the Company model costs for renewable projects after 2030?

A49. After 2030, the Company must apply a cost structure for modeling purposes. A conservative approach was applied using Company-owned assumptions. However, this approach to modeling cost after 2030 does not represent a position by the Company on ownership post 2030.

Voluntary Green Pricing Renewable Energy Systems

Q50. Has the Company included any assets attributable to a voluntary green pricing (VGP) program in the Amended REP?

A50. Yes. The Company included the assets for its VGP program approved in Case No. U-21361 in the Amended REP. Subscribed portions of the assets attributable to VGP have been subtracted from the REP and the revenue from those subscriptions as shown on line 39 of Exhibit A-2. Revenue from the subscribed assets is shown in the ICOC as one of the costs recovered to offset the revenue requirement. These costs are calculated based on the actual or projected subscription fee for the VGP program. VGP programs are discussed in further detail by Witness Smith.

Line No.

Q51. Is the Company proposing any additional assets attributable to its VGP program in its Amended REP?

A51. Yes, the Company is proposing additional solar builds of 300 MW for 2027, 500 MW for 2028, and 130 MW for 2029. These additions are aimed at meeting customer demand within the VGP program. According to Section 9 of the Settlement Agreement in the Company's Section 61 filing Case No. U-21172, projects selected through the RFP process to fulfill VGP demand will be distributed proportionately between VGP Program customers and non-participating customers. The goal of this allocation is to achieve cost parity between participating and non-participating VGP program customers. VGP demand is discussed in further detail by Witness Smith.

Q52. Do the subscribed portions of the VGP programs count toward the RPS targets?

A52. No. Subscribed portions of the VGP programs are incremental to the REP and the associated RECs are retired on behalf of subscribers. Consistent with Sec. 28(2)b, the amount of sales attributable to customers participating in a VGP program is subtracted from the total amount needed for compliance with the RPS.

REC Generation

Q53. What are the Company's forecasts for REC additions to its compliance inventory?

A53. A projection of the RECs that the Company will either self-generate or receive from third party renewable energy systems is provided in Exhibit A-4. The RECs from

Line No.

the Company's self-generation and the Company's Michigan Incentive RECs will be booked at zero value.

Q54. Were any of the RECs shown on Exhibit A-4 used by the Company in a Commission approved VGP program?

A54. No. The RECs used in the Company's VGP programs are not included in Exhibit A-4. To date, the Company has offered two VGP programs. One, the GreenCurrents program, was a customer REC purchase program that was separate and distinct from the REP and is no longer offered. The second program is MIGreenPower. Customers currently may subscribe to MIGreenPower in 5% increments to receive up to 100% of their power attributed from renewable sources. The Company retires RECs on behalf of customers for subscribed portions of the MIGreenPower program. RECs attributed to MIGreenPower are drawn from the generation shown on Exhibit A-3, lines 60-63 and 128-131. The RECs from this generation are tracked separately in Michigan Renewable Energy Certification System (MIRECS) and are not utilized for PA 235 compliance.

Q55. What does the line titled "Transferred EWR Credits" on Exhibit A-4 represent?

A55. These RECs are excess Energy Waste Reduction (EWR) credits that the Company achieved as part of its EWR program. The Company transferred the EWR credits to its REC inventory as approved in prior cost reconciliation and Amended REP filings and is forecasting the 2023 excess EWR credits reflected in column (c) to be transferred to its REC inventory.

Line No.

Q56. Does the 2023 ending balance of the associated costs of RECs align with the reconciliation case?

A56. Yes. The ending balance in 2023 of $1.5 million on page 3, line 14, column (d) of Exhibit A-4 aligns with Case No. U-21550 Exhibit A-2 2023 ending balance.

PART III: REVENUE RECOVERY MECHANISM

Q57. How is the Company proposing to recover revenue?

A57. According to the Company's forecast as shown in Exhibit A-24, there is no need for a revenue recovery mechanism surcharge through 2028. The Company will continue to recover the transfer price revenue through the PSCR through 2028, as permitted by PA 235 Section 47(3), and consistent with its previously approved Amended REP in Case No. U-21361. The Company will file its next Amended REP no later than the second quarter of 2027 with an order required by the first quarter of 2028, as required by PA 235 Section 22(3). Therefore, the Company will address the need for a surcharge, if needed, in its next Amended REP filing.

Q58. What are the requested ICOC levels through 2027, DTE Electric's next anticipated Amended REP filing?

A58. The ICOC levels requested by DTE Electric for the years 2024-2027 are calculated by Witness Vangilder as shown on Exhibit A-22. Table 1 reflects the ICOC requested for the 2024-2027 Amended REP years.

Table 1

2024	2025	2026	2027
($14,585,963)	($132,917,944)	($80,293,075)	$73,454,428

Line No.

Q59. What are the ICOC levels through 2045 in this Amended REP?

A59. Consistent with Section 47(2), line 41 of Exhibit A-2 summarizes the ICOC within the Company's Amended REP though 2045.

Q60. What are the factors that may determine if a surcharge will be necessary to recover the ICOC?

A60. The Company recognizes that there are factors that may change over time and impact the Amended REP. Variations from the Company's long-term energy production forecasts, operating cost forecasts, third party PPA charges, or revenues could all contribute to a reduction in the accrued regulatory liability balance. Furthermore, if any of the assumptions around PTCs and ITCs differ from the plan or if there are changes to the build plan, the projected regulatory liability balance will change. Given these uncertainties, the Company believes it is prudent to maintain a regulatory liability balance to ensure that a regulatory asset does not accrue.

Q61. Does the Company plan to create an accumulation of reserve funds or carry forward a regulatory liability?

A61. Yes. The Company had previously set REP surcharges with the intent to recover the cost of the plan and build an accumulation of reserve funds in advance of plan expenditures which creates a regulatory liability. The running balance of the regulatory liability is highly variable based on the assumptions used. DTE Electric will reconcile to the plan, and if the balance forecast projects a negative balance, resulting in a regulatory asset, the Company will provide updated assumptions and/or implement a surcharge, if necessary.

Line No.

The determination of the projected regulatory liability, including the interest expense, is explained and supported in the testimony and exhibits of Witness Vangilder and is summarized on lines 75-78 of Exhibit A-2.

Q62. Has the Commission commented on the continued use of carrying forward a regulatory liability since the passage of PA 235?

A62. Yes. In its April 25, 2024 Order for Case No. U-21568 the Commission stated that "…any regulatory liability balances should continue forward and be addressed in renewable reconciliation proceedings as is the current practice".

Q63. Does the Company plan on allowing the regulatory liability to reach a balance of $1.5 billion in 2045, as shown in Exhibit A-2, line 78?

A63. No, the Company does not intend to accrue a $1.5 billion regulatory liability by 2045. However, as required by PA 235, Section 45 (3), this model reflects a 20-year plan. As such, changes in assumptions could significantly impact the ending balance in 2045. For revenue recovery purposes, the team focused on the initial three years up to 2027, after which the Company will have filed its next REP.

Q64. What actions will the Company take if it anticipates regulatory asset during an Amended REP period?

A64. If the Company is anticipating a regulatory asset within an Amended REP time period, a surcharge will be proposed in either an Amended REP proceeding or an REP Reconciliation.

Line No.

Q65. Does PA 235 allow for adding a surcharge in an REP Reconciliation proceeding?

A65. Yes, according to PA 235 Section 49 (2), "At the renewable cost reconciliation, an electric provider may propose any necessary modifications of the revenue recovery mechanism to ensure the electric provider's recovery of its incremental cost of compliance with the renewable energy standards."

Q66. Does the Amended REP capture the overall impact of meeting the 100% Clean Energy Standards as directed by PA 235?

A66. No, the cost included in this Amended REP does not fully capture the overall impact of transitioning to 100% clean energy since there are many elements outside of the Amended REP that will be affected.

Q67. Is the Amended REP the appropriate proceeding to assessing the overall impact of transitioning to 100% clean energy, as required by PA 235?

A67. No, the Amended REP alone does not provide a comprehensive view of benefits and savings from other sources. According to the Commission April 25, 2024 Order in Case No. U-21568, "…IRPs remain the most appropriate venue to consider generation diversity as well as renewable resource planning because IRPs allow for the full assessment of renewable resources against other resources (including the consideration of the value of the various resource types…)". In turn, the overall impact of transitioning to 100% clean energy future will be addressed in DTE Electric's IRP proceedings.

Line No.

Q68. Is it possible for the costs related to the Company's Amended REP to fluctuate between now and 2045?

A68. Yes, the costs associated with executing DTE Electric's renewable energy build plan are influenced by various factors that could either raise or lower the Company's implementation costs. The build plan and its related costs will be revised every two years in the Company's Amended REP filings, in accordance with PA 235. DTE Electric is confident that the plan outlined in this Amended REP represents the most cost-effective approach to meeting the RPS and Clean Energy Standards. Additionally, DTE Electric remains committed to procuring renewable assets cost-effectively through the RFP process, as further detailed in the next section of my testimony.

PART IV: OTHER POLICY ASSUMPTIONS AND PROPOSALS

Q69. How do the Company's competitive bidding processes ensure that each bidder is treated in a fair and nondiscriminatory manner?

A69. The Company has implemented a number of competitive RFP processes associated with implementation of the Company's REP, consistent with the competitive bidding procedures described in Case No. U-15806 and approved by the August 25, 2009 Commission Order; the September 9, 2021 Competitive Procurement Guidelines in Case No. U-20852; and the Company's IRP Settlement Agreement approved in the Commission's July 26, 2023 Order in Case No. U-21193. The MPSC Staff has audited all of the RFP processes conducted to date and has found them to be compliant with PA 235's requirements and consistent with Section 5 of Attachment D to the December 4, 2008 Temporary Order in MPSC Case No. U-15800. The Company intends to continue following its established and audited

processes in any future RFPs that may be needed, which generally includes the following steps:

- Maintain a list of potential qualified suppliers. DTE Electric maintains a list of companies who have contacted the Company regarding interest in future Requests for Information or Requests for Proposals.
- Meet with the MPSC Staff to review the goals of each RFP and bid evaluation methodologies consistent with Section 5 of Attachment D to the December 4, 2008 Temporary Order in MPSC Case No. U-15800, the Competitive Procurement Guidelines, and the IRP Settlement Agreement.
- Utilize an independent monitor (IM) to provide support and oversight of the Company's RFP development, administration of the bidding, and proposal evaluation processes.
- Develop timelines for individual RFPs, which may vary depending on the complexity of the product(s) being sought and other potential factors.
- Include the following information for each RFP:
  - Description of the key attributes that will be considered when evaluating proposals;
  - Detailed instructions on how to organize proposals and what specific information is required in each section of a bidder's response, how to submit proposals, and how to navigate through the bidding platform or bidding process;
  - A confidentiality agreement between the Company and potential supplier to be executed and included with the proposal submission; and
  - Pro forma contracts for the products(s) described in the RFP

Line No.

- Receive all RFP responses via a secure, web-based bidding platform, and maintain those bids consistent with industry practices, fair competitive practices and the DTE Energy Confidentiality Policy GV11.
- Evaluate each proposal against any minimum or threshold criteria. Depending on the number of submittals that meet the threshold evaluation criteria, and the type of product being sought, the Company may then rank the proposals based on bid score for further evaluation.
- Evaluate the proposals selected for further review as follows:
  - If necessary, the Competitive Procurement team will develop a list of clarifying questions required to adequately complete the reviews.
  - Subject matter experts from outside the Competitive Procurement team may be asked to review specific, sections.
  - Bids will be ranked based on ratings and weightings of the evaluation criteria.
  - From this ranking, a smaller subset of supplier proposals may be selected, or "short listed" for negotiation. It is at this point that subject matter experts may be requested to participate in technical due diligence activities for projects that will transfer ownership to the Company or be owned by the Company.

Q70. How do the cost assumptions for projects in this Amended REP relate to the cost parameters included in the Company's IRP Settlement Agreement in Case No. U-21193?

A70. The estimated costs for projects are within the range of costs set forth in the IRP Settlement Agreement which states renewable energy projects "are consistent with the Company's IRP if they are determined to be priced at or below fair market value by the IM based on the bids submitted in each respective RFP or at or below 150%

Line No.

of the $52.80 Solar LCOE used in the IRP model on Exhibit A-4.3 (i.e., $79.20). The LCOE calculation will be used for both wind and solar projects if it is higher than the fair market value determined by the IM based on the bids submitted in each respective RFP." The cost assumptions in this case are not intended to displace those values.

Q71. Is DTE Electric seeking approval to include Energy Storage in this Amended REP?

A71. The Company would like the Commission's approval on the Company's conceptual plan to co-locate energy storage with renewables and recover the fixed cost of the storage resource through the PSCR Transfer Price mechanism. Further, the Commission should approve the inclusion of costs for the Pine River long duration energy storage demonstration project, conditional on the Company's successful negotiation of an award from the Department of Energy. Energy storage is further detailed in Witness Bennett's testimony.

Q72. Will DTE Electric pursue funding available through the MI Solar for All program?

A72. Yes, DTE Electric plans on pursuing funding for two of its low-income solar pilots, Community Impact and Community Support, once applications become available. Solar for All is further detailed in Witness Smith's testimony.

PART V: SUMMARY AND CONCLUSIONS

Q73. Does DTE Electric's Amended REP meet the plan requirements of PA 235?

Line No.

A73. Yes. In brief, the testimony and exhibits in this filing demonstrate that the Company's 2024 Amended Renewable Energy Plan:

1. Includes a detailed renewable resource plan that aligns with the Company's IRP and forecasts the expected compliance levels by year to meet the RPS targets set forth in 2023 PA 235;
2. Specifies the assumptions used and risks which may drive performance to vary;
3. Provides updates on the Company's VGP program offerings;
4. Calculates the incremental cost of compliance through 2045;
5. Includes the Company's plan for a revenue recovery mechanism, subject to Section 47, for the electric provider's tariffs that permit recovery of the incremental cost of compliance to implement the Amended REP; and
6. Proposes a plan to pursue co-located energy storage that may be included for recovery in a future Amended REP filing.

The Company has worked diligently to develop a workable and economic Amended REP which runs through 2045 and is designed to achieve the requirements of PA 235. The Company's Amended REP presents reasonable and prudent costs with regard to both the incremental cost of compliance and PSCR Transfer Prices and reasonable and prudent Renewable Energy Plan surcharges, all of which properly address the various elements of PA 235. Therefore, the MPSC should approve all elements of the Company's Amended REP.

Q74. Does this conclude your direct testimony?

A74. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

OF

KEVIN L. BILYEU

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Renewable Energy Credit and Technology Overview

Case No.: U-21662
Exhibit: A-1
Witness: K.L. Bilyeu

Line No.	(a)	Prelim 2022 (b)	Prelim 2022 (c)	Prelim 2023 (d)	Prelim 2023 (e)	2024 (f)	2024 (g)	2025 (h)	2025 (i)	2026 (j)	2026 (k)	2027 (l)	2027 (m)	2028 (n)	2028 (o)	2029 (p)	2029 (q)
		2022		2023		2024		2025		2026		2027		2028		2029	
		RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent
1	**Technology Mix** [1]																
2	Wind	4,132,973	82.8%	3,657,521	80.1%	4,121,901	79.9%	4,208,559	79.6%	4,208,559	73.0%	4,208,559	53.9%	4,655,443	49.4%	5,172,940	43.8%
3	Solar	66,550	1.3%	81,121	1.8%	162,217	3.1%	203,540	3.8%	656,054	11.4%	2,338,950	29.9%	3,282,446	34.8%	4,789,160	40.6%
4	Biomass Prior to 2/27/2024	86,166	1.7%	119,958	2.6%	115,701	2.2%	115,385	2.2%	115,385	2.0%	115,385	1.5%	115,701	1.2%	115,385	1.0%
5	Biomass After 2/27/2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
6	Municipal Solid Waste	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
7	Landfill Gas	231,731	4.6%	212,213	4.6%	216,561	4.2%	216,423	4.1%	216,423	3.8%	216,423	2.8%	216,561	2.3%	216,423	1.8%
8	Hydroelectric	11,930	0.2%	13,975	0.3%	13,975	0.3%	13,975	0.3%	13,975	0.2%	13,975	0.2%	13,975	0.1%	13,975	0.1%
9	Incentive	463,833	9.3%	479,828	10.5%	529,057	10.3%	532,364	10.1%	553,304	9.6%	918,809	11.8%	1,148,289	12.2%	1,500,841	12.7%
10	Other	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
11	**Total**	**4,993,183**	**100.0%**	**4,564,617**	**100.0%**	**5,159,413**	**100.0%**	**5,290,246**	**100.0%**	**5,763,701**	**100.0%**	**7,812,101**	**100.0%**	**9,432,415**	**100.0%**	**11,808,725**	**100.0%**

		2022		2023		2024		2025		2026		2027		2028		2029	
		RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent
12	**Program Type**																
13	PURPA	194,413	16%	180,077	13%	180,077	12%	180,077	8%	180,077	6%	180,077	3%	180,077	3%	180,077	2%
14	Net Metering/DG	4,909	0%	4,549	0%	4,526	0%	4,504	0%	4,481	0%	4,459	0%	4,436	0%	4,414	0%
15	Feed-in Tariffs	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
16	Community Solar	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
17	Other (VGPs)	1,054,368	84%	1,184,525	87%	1,315,354	88%	1,972,144	91%	2,794,617	94%	5,358,090	97%	6,616,223	97%	7,426,909	98%
18	**Total**	**1,253,690**	**100%**	**1,369,151**	**100%**	**1,499,957**	**100%**	**2,156,725**	**100%**	**2,979,175**	**100%**	**5,542,626**	**100%**	**6,800,737**	**100%**	**7,611,400**	**100%**

(1) Excludes Voluntary Green Pricing programs and REC only contracts

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Renewable Energy Credit and Technology Overview

Case No.: U-21662
Exhibit: A-1
Witness: K.L. Bilyeu

Line No.	(a)	(r) 2030 RECs	(s) 2030 Percent	(t) 2031 RECs	(u) 2031 Percent	(v) 2032 RECs	(w) 2032 Percent	(x) 2033 RECs	(y) 2033 Percent	(z) 2034 RECs	(aa) 2034 Percent	(ab) 2035 RECs	(ac) 2035 Percent	(ad) 2036 RECs	(ae) 2036 Percent	(af) 2037 RECs	(ag) 2037 Percent
1	**Technology Mix** [1]																
2	Wind	5,630,911	40.0%	6,171,128	37.7%	6,452,407	36.7%	6,605,984	33.8%	6,588,477	30.9%	8,847,992	37.3%	11,565,882	43.7%	14,222,733	48.9%
3	Solar	6,360,040	45.1%	7,933,405	48.4%	8,778,893	49.9%	10,282,855	52.7%	11,867,260	55.7%	11,916,996	50.2%	11,889,893	44.9%	11,798,124	40.6%
4	Biomass Prior to 2/27/2024	115,385	0.8%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
5	Biomass After 2/27/2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
6	Municipal Solid Waste	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
7	Landfill Gas	216,423	1.5%	192,045	1.2%	166,102	0.9%	166,102	0.9%	166,102	0.8%	166,102	0.7%	166,102	0.6%	166,102	0.6%
8	Hydroelectric	13,975	0.1%	13,975	0.1%	13,975	0.1%	13,975	0.1%	13,975	0.1%	13,975	0.1%	13,975	0.1%	13,975	0.0%
9	Incentive	1,757,865	12.5%	2,073,813	12.7%	2,185,686	12.4%	2,454,928	12.6%	2,684,698	12.6%	2,794,804	11.8%	2,850,930	10.8%	2,887,542	9.9%
10	Other	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
11	**Total**	**14,094,599**	**100.0%**	**16,384,367**	**100.0%**	**17,597,064**	**100.0%**	**19,523,844**	**100.0%**	**21,320,513**	**100.0%**	**23,739,869**	**100.0%**	**26,486,783**	**100.0%**	**29,088,476**	**100.0%**

		2030 RECs	2030 Percent	2031 RECs	2031 Percent	2032 RECs	2032 Percent	2033 RECs	2033 Percent	2034 RECs	2034 Percent	2035 RECs	2035 Percent	2036 RECs	2036 Percent	2037 RECs	2037 Percent
12	**Program Type**																
13	PURPA	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%
14	Net Metering/DG	4,392	0%	4,370	0%	4,348	0%	4,327	0%	4,305	0%	4,283	0%	4,262	0%	4,241	0%
15	Feed-in Tariffs	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
16	Community Solar	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
17	Other (VGPs)	7,415,003	98%	7,385,969	98%	7,375,761	98%	7,328,315	98%	7,299,690	98%	7,271,202	98%	7,261,222	98%	7,214,626	98%
18	**Total**	**7,599,473**	**100%**	**7,570,417**	**100%**	**7,560,187**	**100%**	**7,512,719**	**100%**	**7,484,073**	**100%**	**7,455,562**	**100%**	**7,445,562**	**100%**	**7,398,944**	**100%**

(1) Excludes Voluntary Green Pricing programs and REC only contracts

Michigan Public Service Commission
DTE Electric Company
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Renewable Energy Credit and Technology Overview

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Line No.	(a)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)	(ap)	(aq)	(ar)	(as)	(at)	(au)	(av)	(aw)
		2038		2039		2040		2041		2042		2043		2044		2045	
		RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent
1	**Technology Mix** [1]																
2	Wind	16,913,345	53.3%	19,606,119	57.1%	22,362,152	60.3%	24,998,150	63.1%	26,572,566	63.1%	26,797,534	63.4%	26,870,952	64.0%	26,797,534	64.0%
3	Solar	11,739,133	37.0%	11,680,437	34.0%	11,653,873	31.4%	11,563,925	29.2%	12,388,971	29.4%	12,502,716	29.6%	12,474,282	29.7%	12,378,002	29.7%
4	Biomass Prior to 2/27/2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
5	Biomass After 2/27/2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
6	Municipal Solid Waste	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
7	Landfill Gas	166,102	0.5%	166,102	0.5%	166,102	0.4%	166,102	0.4%	166,102	0.4%	166,102	0.4%	166,102	0.4%	166,102	0.4%
8	Hydroelectric	13,975	0.0%	13,975	0.0%	13,975	0.0%	13,975	0.0%	13,975	0.0%	13,975	0.0%	13,975	0.0%	13,975	0.0%
9	Incentive	2,906,405	9.2%	2,897,454	8.4%	2,897,476	7.8%	2,881,526	7.3%	2,972,726	7.1%	2,757,413	6.5%	2,484,866	5.9%	2,296,797	5.9%
10	Other	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
11	**Total**	**31,738,960**	**100.0%**	**34,364,087**	**100.0%**	**37,093,578**	**100.0%**	**39,623,678**	**100.0%**	**42,114,341**	**100.0%**	**42,237,741**	**100.0%**	**42,010,177**	**100.0%**	**41,652,410**	**100.0%**

		2038		2039		2040		2041		2042		2043		2044		2045	
		RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent	RECs	Percent
12	**Program Type**																
13	PURPA	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%	180,077	2%
14	Net Metering/DG	4,220	0%	4,198	0%	4,177	0%	4,157	0%	4,136	0%	4,115	0%	4,094	0%	4,074	0%
15	Feed-in Tariffs	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
16	Community Solar	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
17	Other (VGPs)	7,186,536	97%	7,158,575	97%	7,148,812	97%	7,103,051	97%	7,075,484	97%	7,048,047	97%	7,038,504	97%	6,993,562	97%
18	**Total**	**7,370,833**	**100%**	**7,342,851**	**100%**	**7,333,067**	**100%**	**7,287,285**	**100%**	**7,259,697**	**100%**	**7,232,239**	**100%**	**7,222,676**	**100%**	**7,177,713**	**100%**

(1) Excludes Voluntary Green Pricing programs and REC only contracts

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Renewable Energy Plan Summary

Case No.: U-21662
Exhibit: A-2
Witness: K.L. Bilyeu

Line No.	(a)	(b)	Prelim (c) 2022	Prelim (d) 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027
1	**Sales and Requirement Calculation**	**Source**						
2	**Method: Weather Normalized or 3 Year Average**							
3	If Selected Weather Normalized:							
4	Current Year Sales to Retail Customers	Exh A-29 Column (i)	40,609,620	40,314,687	39,914,445	39,800,480	39,634,892	39,497,918
5	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-
6	Current Year Weather Normalization Factor	Exh A-29 Column (i)	1.00	1.00	1.00	1.00	1.00	1.00
7	Less VGP sales	WP-6		1,184,525	1,315,354	1,972,144	2,794,617	5,358,090
8	Less Outflow from DG Customers			-	36,177	44,791	55,355	68,099
9	Current Year Weather Normalized Sales		40,609,620	39,130,162	38,562,915	37,783,546	36,784,920	34,071,729
10	If Selected 3 Year Average:							
11	Current Year Retail Sales to Retail Customers							
12	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy							
13	Less VGP sales							
14	Less outflow from DG customers							
15	3 Year Average of sales							
16	RPS Required Energy Credits (For 2024 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	6,166,087	6,091,443	5,869,524	5,784,437	5,667,532	5,517,738
17	**Energy Credits**							
18	Energy Credit Beginning Balance	Row 26	4,707,071	3,765,317	2,857,740	2,661,734	2,455,332	2,833,451
19	Plus: Energy Credits Obtained Through Generation/BOT	Exh A-4 +WP-4 KLB (IRECs)	3,480,765	3,292,553	3,564,334	3,448,305	3,405,313	4,785,213
20	Plus: Energy Credits Obtained Through PPA	Exh A-4 +WP-4 KLB (IRECs)	1,743,568	1,555,236	1,815,708	1,840,508	2,356,962	3,025,469
21	Plus: Energy Credits Obtained Through REC Purchases	Exh A-4 line 7	-	336,077	293,476	289,222	283,377	275,887
22	Less: Energy Credits Sold		-	-	-	-	-	-
23	Available Energy Credits (Rows 18 + 19 + 20 + 21 - 22)	Calculated	9,931,404	8,949,183	8,531,259	8,239,769	8,500,983	10,920,020
24	Less: Compliance Requirement (Row 16)	Calculated	6,166,087	6,091,443	5,869,524	5,784,437	5,667,532	5,517,738
25	Less: Energy Credit Expired		-	-	-	-	-	-
26	Energy Credit Ending Balance (Rows 23 - 24 - 25)	Calculated	3,765,317	2,857,740	2,661,734	2,455,332	2,833,451	5,402,282
27	**Revenue Requirement**							
28	Cost of Renewable Energy Generation/BOT [1]	Exh A-23 line 24 - lines 15,16&22	$ 373,427,207	$ 404,009,702	$ 505,078,243	$ 676,929,551	$ 934,234,714	$ 1,252,223,498
29	Cost of Renewable Energy PPA	Exh A-23 line 15	$ 108,366,168	$ 98,164,158	$ 113,197,489	$ 114,167,198	$ 148,768,592	$ 209,966,187
30	Cost of Renewable Energy Credit Purchases	Exh A-23 line 16	$ 1,955,599	$ 1,298,469	$ 4,059,509	$ 2,588,758	$ 2,900,279	$ 3,304,569
31	Costs of Administration of Renewable Energy Plan	ATT-1 PDK line 2	$ -	$ 515,328	$ 528,212	$ 541,417	$ 554,952	$ 568,826
32	Less: Revenue obtained from Renewable Energy Sales (non-retail)							
33	REP Total Revenue Requirement (Rows 28 + 29 + 30 + 31 - 32)	Calculated	$ 483,748,974	$ 503,987,658	$ 622,863,453	$ 794,226,923	$ 1,086,458,537	$ 1,466,063,080
34	**Cost Recovery**							
35	Forecasted Transfer Price per MWH	Exh A-21 line 152 / line 151	$ 78.70	$ 81.48	$ 82.17	$ 83.17	$ 82.99	$ 80.43
36	MWH of Renewable Energy	Exh A-21 line 151	4,377,142	3,802,808	4,448,838	4,576,372	5,028,893	6,711,796
37	Amount Recovered Through the PSCR	Exh A-21 line 14	$ 328,689,309	$ 309,836,315	$ 365,541,300	$ 380,621,882	$ 417,344,692	$ 539,801,654
38	Federal Tax Impacts (including PTC/ITC/TCJA Remeasurement) (1)	Exh A-22 line 10, 11, 12, and 23	$ 115,230,057	$ 111,137,751	$ 105,753,446	$ 263,175,736	$ 317,561,949	$ 342,748,102
39	Revenue from Voluntary Green Pricing Programs (2)	Exh A-22 line 14, 15 and 18	$ 50,446,783	$ 57,426,632	$ 65,031,080	$ 105,487,777	$ 159,399,224	$ 311,969,951
40	AFUDC Impacts	Exh A-22 line 36, 37, 38, 39, 40	$ -	$ 10,745,069	$ 101,123,590	$ 177,859,418	$ 272,445,425	$ 198,087,992
41	Incremental Cost of Compliance (Rows 33 - 40)	Calculated	$ (10,617,175)	$ 14,841,891	$ (14,585,963)	$ (132,917,889)	$ (80,292,753)	$ 73,455,381
42	**Non-Volumetric Meter/Customer Charge Forecast**							
43	Residential		$ -	$ -	$ -	$ -	$ -	$ -
44	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
45	Primary		$ -	$ -	$ -	$ -	$ -	$ -
46	Other		$ -	$ -	$ -	$ -	$ -	$ -
47	**Meter/Customer Count**							
48	Residential	Exh A-26 Column (b)	2,047,591	2,055,845	2,064,797	2,074,827	2,084,117	2,092,054
49	Secondary	Exh A-26 Column (c)	207,478	208,286	209,555	210,629	211,588	212,397
50	Primary	Exh A-26 Column (d)	2,816	2,823	2,818	2,818	2,818	2,818
51	Other		-	-	-	-	-	-
52	**Planned Non-Volumetric Revenue**							
53	Residential (Rows 43 * 48)		$ -	$ -	$ -	$ -	$ -	$ -
54	Secondary (Rows 44 * 49)		$ -	$ -	$ -	$ -	$ -	$ -
55	Primary (Rows 45 * 50)		$ -	$ -	$ -	$ -	$ -	$ -
56	Other (Rows 46 * 51)		$ -	$ -	$ -	$ -	$ -	$ -
57	Total (Rows 53 + 54 + 55 + 56)		$ -	$ -	$ -	$ -	$ -	$ -
58	**Volumetric (kWh) Charge Forecast**							
59	Residential		$ -	$ -	$ -	$ -	$ -	$ -
60	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
61	Primary		$ -	$ -	$ -	$ -	$ -	$ -
62	Other		$ -	$ -	$ -	$ -	$ -	$ -
63	**kWh**							
64	Residential		15,844,478	14,451,501	15,289,865	15,274,274	15,325,354	15,402,435
65	Secondary		10,013,981	9,765,601	9,901,101	9,856,329	9,812,956	9,788,528
66	Primary		14,829,510	14,701,283	14,492,454	14,432,043	14,249,341	14,047,925
67	Other		209,674	203,563	194,848	193,043	191,886	190,930
68	**Planned Volumetric Revenue**							
69	Residential (Rows 59 * 64)		$ -	$ -	$ -	$ -	$ -	$ -
70	Secondary (Rows 60 * 65)		$ -	$ -	$ -	$ -	$ -	$ -
71	Primary (Rows 61 * 66)		$ -	$ -	$ -	$ -	$ -	$ -
72	Other (Rows 62 * 67)		$ -	$ -	$ -	$ -	$ -	$ -
73	Total (Rows 69 + 70 + 71 + 72)		$ -	$ -	$ -	$ -	$ -	$ -
74	**Year-End Regulatory Liability Balance**							
75	Current Year Regulatory Liability Balance (Row 57 + 73 - 41)	Calculated	$ 10,617,175	$ (14,841,891)	$ 14,585,963	$ 132,917,889	$ 80,292,753	$ (73,455,381)
76	Forecasted Ending Balance	Calculated	$ 19,430,429	$ 4,926,334	$ 20,247,158	$ 153,878,644	$ 238,195,527	$ 172,823,512
77	Carrying Charges	ATT-3 KV line 7	$ 337,797	$ 734,860	$ 713,597	$ 4,024,129	$ 8,083,367	$ 8,552,838
78	Total Cumulative Reg Liability (Rows 76 + 77)	Calculated	$ 19,768,226	$ 5,661,195	$ 20,960,755	$ 157,902,773	$ 246,278,893	$ 181,376,351
79	**Cumulative Megawatts by Year**							
80	DTE Owned Wind	WP-7 KLB line 2	1,461	1,491	1,491	1,491	1,491	1,491
81	DTE Owned Solar	WP-7 KLB line 18	65	65	75	421	1,136	2,663

(1) The Company has modeled costs after 2030 using Company-owned assumptions. This does not represent a position by the Company on ownership post 2030.

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Renewable Energy Plan Summary

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Line No.	(a)	(b)	(i) 2028	(j) 2029	(k) 2030	(l) 2031	(m) 2032	(n) 2033
1	**Sales and Requirement Calculation**	**Source**						
2	**Method: Weather Normalized or 3 Year Average**							
3	If Selected Weather Normalized:							
4	Current Year Sales to Retail Customers	Exh A-29 Column (i)	39,869,525	39,910,589	40,013,252	40,203,583	40,511,120	40,702,673
5	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-
6	Current Year Weather Normalization Factor	Exh A-29 Column (i)	1.00	1.00	1.00	1.00	1.00	1.00
7	Less VGP sales	WP-6	6,616,223	7,426,909	7,415,003	7,385,969	7,375,761	7,328,315
8	Less Outflow from DG Customers		83,171	100,829	121,202	143,020	164,705	185,876
9	Current Year Weather Normalized Sales		33,170,131	32,382,850	32,477,046	32,674,594	32,970,654	33,188,482
10	If Selected 3 Year Average:							
11	Current Year Retail Sales to Retail Customers							
12	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy							
13	Less VGP sales							
14	Less outflow from DG customers							
15	3 Year Average of sales							
16	RPS Required Energy Credits (For 2024 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	5,110,759	4,975,520	16,191,425	16,238,523	16,337,297	16,485,327
17	**Energy Credits**							
18	Energy Credit Beginning Balance	Row 26	5,402,282	9,978,064	17,058,641	15,769,987	16,726,366	18,801,613
19	Plus: Energy Credits Obtained Through Generation/BOT	Exh A-4 +WP-4 KLB (IRECs)	5,979,683	7,689,837	9,356,714	11,743,705	13,258,615	15,574,681
20	Plus: Energy Credits Obtained Through PPA	Exh A-4 +WP-4 KLB (IRECs)	3,451,320	4,117,483	4,736,487	4,639,271	4,337,065	3,947,786
21	Plus: Energy Credits Obtained Through REC Purchases	Exh A-4 line 7	255,538	248,776	809,571	811,926	816,865	824,266
22	Less: Energy Credits Sold		-	-	-	-	-	-
23	Available Energy Credits (Rows 18 + 19 + 20 + 21 - 22)	Calculated	15,088,824	22,034,160	31,961,412	32,964,889	35,138,910	39,148,347
24	Less: Compliance Requirement (Row 16)	Calculated	5,110,759	4,975,520	16,191,425	16,238,523	16,337,297	16,485,327
25	Less: Energy Credit Expired		-	-	-	-	-	-
26	Energy Credit Ending Balance (Rows 23 - 24 - 25)	Calculated	9,978,064	17,058,641	15,769,987	16,726,366	18,801,613	22,663,019
27	**Revenue Requirement**							
28	Cost of Renewable Energy Generation/BOT (1)	Exh A-23 line 24 - lines 15,16&22	$ 1,448,956,595	$ 1,597,052,348	$ 1,734,732,134	$ 1,898,403,003	$ 2,032,771,656	$ 2,217,667,944
29	Cost of Renewable Energy PPA	Exh A-23 line 15	$ 263,037,439	$ 313,260,874	$ 347,818,689	$ 337,249,823	$ 309,766,112	$ 285,812,244
30	Cost of Renewable Energy Credit Purchases	Exh A-23 line 16	$ 3,526,169	$ 3,945,094	$ 8,649,183	$ 9,594,196	$ 10,397,140	$ 11,148,229
31	Costs of Administration of Renewable Energy Plan	ATT-1 PDK line 2	$ 583,047	$ 597,623	$ 612,563	$ 627,878	$ 643,574	$ 659,664
32	Less: Revenue obtained from Renewable Energy Sales (non-retail)							
33	REP Total Revenue Requirement (Rows 28 + 29 + 30 + 31 - 32)	Calculated	$ 1,716,103,250	$ 1,914,855,938	$ 2,091,812,570	$ 2,245,874,900	$ 2,353,578,483	$ 2,515,288,080
34	**Cost Recovery**							
35	Forecasted Transfer Price per MWH	Exh A-21 line 152 / line 151	$ 80.27	$ 79.95	$ 79.52	$ 79.77	$ 80.56	$ 75.62
36	MWH of Renewable Energy	Exh A-21 line 151	8,102,637	10,126,401	12,155,258	14,129,085	15,229,916	16,887,462
37	Amount Recovered Through the PSCR	Exh A-21 line 14	$ 650,413,860	$ 809,571,107	$ 966,530,672	$ 1,127,045,325	$ 1,226,864,368	$ 1,277,043,370
38	Federal Tax Impacts (including PTC/ITC/TCJA Remeasurement) (1)	Exh A-22 line 10, 11, 12, and 23	$ 323,403,897	$ 434,652,712	$ 514,804,912	$ 570,624,075	$ 607,947,890	$ 693,191,624
39	Revenue from Voluntary Green Pricing Programs (2)	Exh A-22 line 14, 15 and 18	$ 377,899,125	$ 423,868,700	$ 423,051,837	$ 421,373,513	$ 420,759,610	$ 418,040,625
40	AFUDC Impacts	Exh A-22 line 36, 37, 38, 39, 40	$ 191,400,495	$ 158,845,076	$ 169,818,984	$ 148,755,172	$ 180,927,652	$ 191,276,765
41	Incremental Cost of Compliance (Rows 33 - 40)	Calculated	$ 172,985,874	$ 87,918,344	$ 17,606,164	$ (21,923,185)	$ (82,921,037)	$ (64,264,304)
42	**Non-Volumetric Meter/Customer Charge Forecast**							
43	Residential		$ -	$ -	$ -	$ -	$ -	$ -
44	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
45	Primary		$ -	$ -	$ -	$ -	$ -	$ -
46	Other		$ -	$ -	$ -	$ -	$ -	$ -
47	**Meter/Customer Count**							
48	Residential	Exh A-26 Column (b)	2,098,709	2,104,525	2,110,138	2,115,485	2,120,393	2,125,749
49	Secondary	Exh A-26 Column (c)	213,071	213,660	214,227	214,767	215,263	215,804
50	Primary	Exh A-26 Column (d)	2,818	2,818	2,818	2,818	2,818	2,818
51	Other		-	-	-	-	-	-
52	**Planned Non-Volumetric Revenue**							
53	Residential (Rows 43 * 48)		$ -	$ -	$ -	$ -	$ -	$ -
54	Secondary (Rows 44 * 49)		$ -	$ -	$ -	$ -	$ -	$ -
55	Primary (Rows 45 * 50)		$ -	$ -	$ -	$ -	$ -	$ -
56	Other (Rows 46 * 51)		$ -	$ -	$ -	$ -	$ -	$ -
57	Total (Rows 53 + 54 + 55 + 56)		$ -	$ -	$ -	$ -	$ -	$ -
58	**Volumetric (kWh) Charge Forecast**							
59	Residential		$ -	$ -	$ -	$ -	$ -	$ -
60	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
61	Primary		$ -	$ -	$ -	$ -	$ -	$ -
62	Other		$ -	$ -	$ -	$ -	$ -	$ -
63	**kWh**							
64	Residential		15,577,904	15,678,999	15,828,763	15,983,138	16,206,640	16,347,303
65	Secondary		9,805,191	9,787,112	9,787,087	9,805,146	9,870,886	9,900,050
66	Primary		14,211,310	14,149,762	14,080,221	14,074,610	14,069,603	14,068,305
67	Other		191,950	193,886	195,979	197,669	199,287	201,139
68	**Planned Volumetric Revenue**							
69	Residential (Rows 59 * 64)		$ -	$ -	$ -	$ -	$ -	$ -
70	Secondary (Rows 60 * 65)		$ -	$ -	$ -	$ -	$ -	$ -
71	Primary (Rows 61 * 66)		$ -	$ -	$ -	$ -	$ -	$ -
72	Other (Rows 62 * 67)		$ -	$ -	$ -	$ -	$ -	$ -
73	Total (Rows 69 + 70 + 71 + 72)		$ -	$ 75,500,000	$ 17,600,000	$ -	$ -	$ -
74	**Year-End Regulatory Liability Balance**							
75	Current Year Regulatory Liability Balance (Row 57 + 73 - 41)	Calculated	$ (172,985,874)	$ (12,418,344)	$ (6,164)	$ 21,923,185	$ 82,921,037	$ 64,264,304
76	Forecasted Ending Balance	Calculated	$ 8,390,477	$ (155,347)	$ 85,312	$ 22,011,833	$ 105,383,628	$ 172,256,767
77	Carrying Charges	ATT-3 KV line 7	$ 3,872,520	$ 246,823	$ 3,336	$ 450,758	$ 2,608,835	$ 5,719,100
78	Total Cumulative Reg Liability (Rows 76 + 77)	Calculated	$ 12,262,997	$ 91,476	$ 88,648	$ 22,462,591	$ 107,992,463	$ 177,975,867
79	**Cumulative Megawatts by Year**							
80	DTE Owned Wind	WP-7 KLB line 2	1,631	1,771	1,911	2,111	2,311	2,511
81	DTE Owned Solar	WP-7 KLB line 18	3,477	4,324	4,884	5,684	6,084	6,884

(1) The Company has modeled costs after 2030 using Company-owned assumptions. This does not represent a position by the Company on ownership post 2030.

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DTE Electric Company
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Line No.	(a)	(b)	(o) 2034	(p) 2035	(q) 2036	(r) 2037	(s) 2038	(t) 2039
1	**Sales and Requirement Calculation**	**Source**						
2	**Method: Weather Normalized or 3 Year Average**							
3	If Selected Weather Normalized:							
4	Current Year Sales to Retail Customers	Exh A-29 Column (i)	41,076,945	41,418,790	41,796,601	41,972,411	42,220,700	42,421,326
5	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-
6	Current Year Weather Normalization Factor	Exh A-29 Column (i)	1.00	1.00	1.00	1.00	1.00	1.00
7	Less VGP sales	WP-6	7,299,690	7,271,202	7,261,222	7,214,626	7,186,536	7,158,575
8	Less Outflow from DG Customers		204,715	222,048	239,754	257,838	276,311	295,137
9	Current Year Weather Normalized Sales		33,572,540	33,925,541	34,295,625	34,499,947	34,757,853	34,967,614
10	If Selected 3 Year Average:							
11	Current Year Retail Sales to Retail Customers							
12	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy							
13	Less VGP sales							
14	Less outflow from DG customers							
15	3 Year Average of sales							
16	RPS Required Energy Credits (For 2024 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	16,594,241	20,143,524	20,355,325	20,577,375	20,699,968	20,854,712
17	**Energy Credits**							
18	Energy Credit Beginning Balance	Row 26	22,663,019	28,217,633	32,819,791	39,967,659	49,506,278	61,578,926
19	Plus: Energy Credits Obtained Through Generation/BOT	Exh A-4 +WP-4 KLB (IRECs)	17,938,444	20,437,898	23,189,448	25,812,563	28,475,980	31,113,974
20	Plus: Energy Credits Obtained Through PPA	Exh A-4 +WP-4 KLB (IRECs)	3,380,699	3,300,608	3,295,979	3,274,563	3,261,638	3,248,777
21	Plus: Energy Credits Obtained Through REC Purchases	Exh A-4 line 7	829,712	1,007,176	1,017,766	1,028,869	1,034,998	1,042,736
22	Less: Energy Credits Sold		-	-	-	-	-	-
23	Available Energy Credits (Rows 18 + 19 + 20 + 21 - 22)	Calculated	44,811,874	52,963,314	60,322,983	70,083,653	82,278,894	96,984,412
24	Less: Compliance Requirement (Row 16)	Calculated	16,594,241	20,143,524	20,355,325	20,577,375	20,699,968	20,854,712
25	Less: Energy Credit Expired		-	-	-	-	-	-
26	Energy Credit Ending Balance (Rows 23 - 24 - 25)	Calculated	28,217,633	32,819,791	39,967,659	49,506,278	61,578,926	76,129,701
27	**Revenue Requirement**							
28	Cost of Renewable Energy Generation/BOT (1)	Exh A-23 line 24 - lines 15,16&22	$ 2,401,470,536	$ 2,585,454,757	$ 2,762,948,226	$ 2,933,770,309	$ 3,105,791,011	$ 3,271,556,194
29	Cost of Renewable Energy PPA	Exh A-23 line 15	$ 257,645,330	$ 253,218,319	$ 253,038,679	$ 251,484,390	$ 250,630,992	$ 249,784,074
30	Cost of Renewable Energy Credit Purchases	Exh A-23 line 16	$ 11,758,663	$ 13,585,879	$ 14,633,360	$ 15,672,396	$ 16,692,154	$ 17,720,003
31	Costs of Administration of Renewable Energy Plan	ATT-1 PDK line 2	$ 676,155	$ 693,059	$ 710,386	$ 728,145	$ 746,349	$ 765,008
32	Less: Revenue obtained from Renewable Energy Sales (non-retail)							
33	REP Total Revenue Requirement (Rows 28 + 29 + 30 + 31 - 32)	Calculated	$ 2,671,550,684	$ 2,852,952,013	$ 3,031,330,651	$ 3,201,655,241	$ 3,373,860,505	$ 3,539,825,279
34	**Cost Recovery**							
35	Forecasted Transfer Price per MWH	Exh A-21 line 152 / line 151	$ 63.78	$ 61.75	$ 61.37	$ 61.18	$ 61.13	$ 61.18
36	MWH of Renewable Energy	Exh A-21 line 151	18,454,367	20,763,624	23,454,419	26,019,507	28,651,135	31,285,220
37	Amount Recovered Through the PSCR	Exh A-21 line 14	$ 1,177,033,921	$ 1,282,170,804	$ 1,439,457,766	$ 1,591,970,014	$ 1,751,531,729	$ 1,913,918,584
38	Federal Tax Impacts (including PTC/ITC/TCJA Remeasurement) (1)	Exh A-22 line 10, 11, 12, and 23	$ 757,698,532	$ 908,414,970	$ 1,013,190,817	$ 1,006,389,724	$ 1,015,795,801	$ 998,588,502
39	Revenue from Voluntary Green Pricing Programs (2)	Exh A-22 line 14, 15 and 18	$ 416,385,774	$ 414,738,683	$ 414,137,715	$ 411,467,574	$ 409,843,328	$ 408,226,440
40	AFUDC Impacts	Exh A-22 line 36, 37, 38, 39, 40	$ 199,980,347	$ 202,299,495	$ 202,737,654	$ 203,147,471	$ 203,323,309	$ 200,287,370
41	Incremental Cost of Compliance (Rows 33 - 40)	Calculated	$ 120,452,110	$ 45,328,061	$ (38,193,302)	$ (11,319,542)	$ (6,633,662)	$ 18,804,384
42	**Non-Volumetric Meter/Customer Charge Forecast**							
43	Residential		$ -	$ -	$ -	$ -	$ -	$ -
44	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
45	Primary		$ -	$ -	$ -	$ -	$ -	$ -
46	Other		$ -	$ -	$ -	$ -	$ -	$ -
47	**Meter/Customer Count**							
48	Residential	Exh A-26 Column (b)	2,131,503	2,136,966	2,141,956	2,146,350	2,150,168	2,153,450
49	Secondary	Exh A-26 Column (c)	216,385	216,937	217,441	217,885	218,271	218,603
50	Primary	Exh A-26 Column (d)	2,818	2,818	2,818	2,818	2,818	2,818
51	Other		-	-	-	-	-	-
52	**Planned Non-Volumetric Revenue**							
53	Residential (Rows 43 * 48)		$ -	$ -	$ -	$ -	$ -	$ -
54	Secondary (Rows 44 * 49)		$ -	$ -	$ -	$ -	$ -	$ -
55	Primary (Rows 45 * 50)		$ -	$ -	$ -	$ -	$ -	$ -
56	Other (Rows 46 * 51)		$ -	$ -	$ -	$ -	$ -	$ -
57	Total (Rows 53 + 54 + 55 + 56)		$ -	$ -	$ -	$ -	$ -	$ -
58	**Volumetric (kWh) Charge Forecast**							
59	Residential		$ -	$ -	$ -	$ -	$ -	$ -
60	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
61	Primary		$ -	$ -	$ -	$ -	$ -	$ -
62	Other		$ -	$ -	$ -	$ -	$ -	$ -
63	**kWh**							
64	Residential		16,569,088	16,781,822	16,992,647	17,069,709	17,151,482	17,200,921
65	Secondary		9,980,337	10,058,966	10,154,548	10,184,188	10,240,044	10,281,669
66	Primary		14,121,666	14,154,815	14,208,513	14,259,537	14,351,723	14,442,460
67	Other		201,139	201,139	201,139	201,139	201,139	201,139
68	**Planned Volumetric Revenue**							
69	Residential (Rows 59 * 64)		$ -	$ -	$ -	$ -	$ -	$ -
70	Secondary (Rows 60 * 65)		$ -	$ -	$ -	$ -	$ -	$ -
71	Primary (Rows 61 * 66)		$ -	$ -	$ -	$ -	$ -	$ -
72	Other (Rows 62 * 67)		$ -	$ -	$ -	$ -	$ -	$ -
73	Total (Rows 69 + 70 + 71 + 72)		$ -	$ -	$ -	$ -	$ -	$ -
74	**Year-End Regulatory Liability Balance**							
75	Current Year Regulatory Liability Balance (Row 57 + 73 - 41)	Calculated	$ (120,452,110)	$ (45,328,061)	$ 38,193,302	$ 11,319,542	$ 6,633,662	$ (18,804,384)
76	Forecasted Ending Balance	Calculated	$ 57,523,757	$ 17,001,539	$ 56,813,572	$ 69,672,308	$ 78,918,454	$ 63,199,579
77	Carrying Charges	ATT-3 KV line 7	$ 4,805,843	$ 1,618,731	$ 1,539,194	$ 2,612,485	$ 3,085,508	$ 2,963,065
78	Total Cumulative Reg Liability (Rows 76 + 77)	Calculated	$ 62,329,600	$ 18,620,270	$ 58,352,766	$ 72,284,792	$ 82,003,963	$ 66,162,644
79	**Cumulative Megawatts by Year**							
80	DTE Owned Wind	WP-7 KLB line 2	2,711	3,711	4,711	5,711	6,711	7,711
81	DTE Owned Solar	WP-7 KLB line 18	7,684	7,684	7,684	7,684	7,684	7,684

(1) The Company has modeled costs after 2030 using Company-owned assumptions. This does not represent a position by the Company on ownership post 2030.

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DTE Electric Company
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Line No.	(a)	(b)	(u) 2040	(v) 2041	(w) 2042	(x) 2043	(y) 2044	(z) 2045
1	**Sales and Requirement Calculation**	**Source**						
2	**Method: Weather Normalized or 3 Year Average**							
3	If Selected Weather Normalized:							
4	Current Year Sales to Retail Customers	Exh A-29 Column (i)	42,654,688	42,699,590	42,849,878	43,041,817	43,325,884	43,439,572
5	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-
6	Current Year Weather Normalization Factor	Exh A-29 Column (i)	1.00	1.00	1.00	1.00	1.00	1.00
7	Less VGP sales	WP-6	7,148,812	7,103,051	7,075,484	7,048,047	7,038,504	6,993,562
8	Less Outflow from DG Customers		313,920	332,890	352,794	373,097	393,673	414,458
9	Current Year Weather Normalized Sales		35,191,955	35,263,649	35,421,600	35,620,672	35,893,707	36,031,552
10	If Selected 3 Year Average:							
11	Current Year Retail Sales to Retail Customers							
12	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy							
13	Less VGP sales							
14	Less outflow from DG customers							
15	3 Year Average of sales							
16	RPS Required Energy Credits (For 2024 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	20,980,568	21,115,173	21,158,189	21,252,960	21,372,403	21,536,224
17	**Energy Credits**							
18	Energy Credit Beginning Balance	Row 26	76,129,701	93,290,409	112,853,350	134,866,094	156,912,213	178,617,304
19	Plus: Energy Credits Obtained Through Generation/BOT	Exh A-4 +WP-4 KLB (IRECs)	33,847,982	36,399,106	38,902,443	39,038,455	38,815,294	38,478,159
20	Plus: Energy Credits Obtained Through PPA	Exh A-4 +WP-4 KLB (IRECs)	3,244,266	3,223,249	3,210,581	3,197,976	3,193,581	3,172,955
21	Plus: Energy Credits Obtained Through REC Purchases	Exh A-4 line 7	1,049,028	1,055,759	1,057,909	1,062,648	1,068,620	1,076,811
22	Less: Energy Credits Sold		-	-	-	-	-	-
23	Available Energy Credits (Rows 18 + 19 + 20 + 21 - 22)	Calculated	114,270,978	133,968,523	156,024,284	178,165,173	199,989,708	221,345,229
24	Less: Compliance Requirement (Row 16)	Calculated	20,980,568	21,115,173	21,158,189	21,252,960	21,372,403	21,536,224
25	Less: Energy Credit Expired		-	-	-	-	-	-
26	Energy Credit Ending Balance (Rows 23 - 24 - 25)	Calculated	93,290,409	112,853,350	134,866,094	156,912,213	178,617,304	199,809,005
27	**Revenue Requirement**							
28	Cost of Renewable Energy Generation/BOT (1)	Exh A-23 line 24 - lines 15,16&22	$ 3,423,749,122	$ 3,521,975,876	$ 3,540,334,535	$ 3,417,147,116	$ 3,309,193,417	$ 3,206,325,116
29	Cost of Renewable Energy PPA	Exh A-23 line 15	$ 249,628,629	$ 248,116,978	$ 247,295,218	$ 246,481,261	$ 246,349,608	$ 244,879,491
30	Cost of Renewable Energy Credit Purchases	Exh A-23 line 16	$ 18,746,126	$ 19,763,609	$ 20,763,689	$ 21,776,760	$ 22,801,405	$ 23,826,494
31	Costs of Administration of Renewable Energy Plan	ATT-1 PDK line 2	$ 784,133	$ 803,736	$ 823,830	$ 844,425	$ 865,536	$ 887,175
32	Less: Revenue obtained from Renewable Energy Sales (non-retail)							
33	REP Total Revenue Requirement (Rows 28 + 29 + 30 + 31 - 32)	Calculated	$ 3,692,908,010	$ 3,790,660,200	$ 3,809,217,271	$ 3,686,249,562	$ 3,579,209,966	$ 3,475,918,275
34	**Cost Recovery**							
35	Forecasted Transfer Price per MWH	Exh A-21 line 152 / line 151	$ 61.31	$ 61.51	$ 61.39	$ 61.36	$ 61.37	$ 61.38
36	MWH of Renewable Energy	Exh A-21 line 151	34,014,695	36,560,752	38,960,221	39,298,941	39,343,931	39,174,239
37	Amount Recovered Through the PSCR	Exh A-21 line 14	$ 2,085,371,198	$ 2,248,950,928	$ 2,391,730,634	$ 2,411,578,383	$ 2,414,593,381	$ 2,404,438,919
38	Federal Tax Impacts (including PTC/ITC/TCJA Remeasurement) (1)	Exh A-22 line 10, 11, 12, and 23	$ 1,129,599,998	$ 1,155,703,784	$ 1,209,596,337	$ 1,127,736,089	$ 1,097,504,410	$ 1,010,735,088
39	Revenue from Voluntary Green Pricing Programs (2)	Exh A-22 line 14, 15 and 18	$ 407,637,626	$ 405,015,502	$ 403,421,155	$ 401,834,309	$ 401,257,926	$ 398,682,844
40	AFUDC Impacts	Exh A-22 line 36, 37, 38, 39, 40	$ 185,083,587	$ 117,625,330	$ (6,276,112)	$ (31,960,215)	$ (32,071,533)	$ (32,071,533)
41	Incremental Cost of Compliance (Rows 33 - 40)	Calculated	$ (114,784,398)	$ (136,635,344)	$ (189,254,743)	$ (222,939,004)	$ (302,074,218)	$ (305,867,042)
42	**Non-Volumetric Meter/Customer Charge Forecast**							
43	Residential		$ -	$ -	$ -	$ -	$ -	$ -
44	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
45	Primary		$ -	$ -	$ -	$ -	$ -	$ -
46	Other		$ -	$ -	$ -	$ -	$ -	$ -
47	**Meter/Customer Count**							
48	Residential	Exh A-26 Column (b)	2,156,186	2,158,382	2,160,663	2,163,523	2,166,450	2,169,196
49	Secondary	Exh A-26 Column (c)	218,879	219,101	219,331	219,620	219,916	220,193
50	Primary	Exh A-26 Column (d)	2,818	2,818	2,818	2,818	2,818	2,818
51	Other		-	-	-	-	-	-
52	**Planned Non-Volumetric Revenue**							
53	Residential (Rows 43 * 48)		$ -	$ -	$ -	$ -	$ -	$ -
54	Secondary (Rows 44 * 49)		$ -	$ -	$ -	$ -	$ -	$ -
55	Primary (Rows 45 * 50)		$ -	$ -	$ -	$ -	$ -	$ -
56	Other (Rows 46 * 51)		$ -	$ -	$ -	$ -	$ -	$ -
57	Total (Rows 53 + 54 + 55 + 56)		$ -	$ -	$ -	$ -	$ -	$ -
58	**Volumetric (kWh) Charge Forecast**							
59	Residential		$ -	$ -	$ -	$ -	$ -	$ -
60	Secondary		$ -	$ -	$ -	$ -	$ -	$ -
61	Primary		$ -	$ -	$ -	$ -	$ -	$ -
62	Other		$ -	$ -	$ -	$ -	$ -	$ -
63	**kWh**							
64	Residential		17,260,074	17,204,770	17,201,177	17,229,496	17,310,539	17,293,905
65	Secondary		10,336,036	10,334,366	10,368,735	10,420,110	10,503,575	10,537,486
66	Primary		14,543,518	14,626,425	14,726,033	14,817,974	14,916,958	14,992,583
67	Other		201,139	201,139	201,139	201,139	201,139	201,139
68	**Planned Volumetric Revenue**							
69	Residential (Rows 59 * 64)		$ -	$ -	$ -	$ -	$ -	$ -
70	Secondary (Rows 60 * 65)		$ -	$ -	$ -	$ -	$ -	$ -
71	Primary (Rows 61 * 66)		$ -	$ -	$ -	$ -	$ -	$ -
72	Other (Rows 62 * 67)		$ -	$ -	$ -	$ -	$ -	$ -
73	Total (Rows 69 + 70 + 71 + 72)		$ -	$ -	$ -	$ -	$ -	$ -
74	**Year-End Regulatory Liability Balance**							
75	Current Year Regulatory Liability Balance (Row 57 + 73 - 41)	Calculated	$ 114,784,398	$ 136,635,344	$ 189,254,743	$ 222,939,004	$ 302,074,218	$ 305,867,042
76	Forecasted Ending Balance	Calculated	$ 180,947,043	$ 322,625,169	$ 522,259,537	$ 762,652,642	$ 1,091,305,491	$ 1,435,550,561
77	Carrying Charges	ATT-3 KV line 7	$ 5,042,783	$ 10,379,625	$ 17,454,101	$ 26,578,631	$ 38,378,028	$ 52,351,441
78	Total Cumulative Reg Liability (Rows 76 + 77)	Calculated	$ 185,989,825	$ 333,004,794	$ 539,713,639	$ 789,231,273	$ 1,129,683,519	$ 1,487,902,002
79	**Cumulative Megawatts by Year**							
80	DTE Owned Wind	WP-7 KLB line 2	8,711	9,711	10,211	10,211	10,211	10,211
81	DTE Owned Solar	WP-7 KLB line 18	7,684	7,684	8,184	8,184	8,184	8,184

(1) The Company has modeled costs after 2030 using Company-owned assumptions. This does not represent a position by the Company on ownership post 2030.

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Generation from DTE Electric Renewable Energy Facilities

Case No.: U-21662
Exhibit: A-3
Witness: K.L. Bilyeu

Line No.	(a)	(b)	(c)	(d) Prelim 2022	(e) Prelim 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029
1	**DTE Electric Owned**										
2	Gratiot County Wind	Installed Capacity	**MW**	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
3		Generation	**1,000 MWh**	251.5	190.7	232.1	231.4	231.4	231.4	232.1	231.4
4	Minden Wind Park	Installed Capacity	**MW**	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
5		Generation	**1,000 MWh**	118.5	104.0	113.2	112.9	112.9	112.9	113.2	112.9
6	McKinley Wind Park	Installed Capacity	**MW**	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
7		Generation	**1,000 MWh**	53.1	48.6	52.0	51.8	51.8	51.8	52.0	51.8
8	Sigel Wind Park	Installed Capacity	**MW**	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
9		Generation	**1,000 MWh**	257.1	228.3	250.1	249.4	249.4	249.4	250.1	249.4
10	Echo Wind Park	Installed Capacity	**MW**	112.0	112.0	112.0	112.0	112.0	112.0	112.0	112.0
11		Generation	**1,000 MWh**	406.4	356.3	388.9	387.9	387.9	387.9	388.9	387.9
12	Brookfield Wind Park	Installed Capacity	**MW**	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
13		Generation	**1,000 MWh**	263.5	218.6	251.1	250.4	250.4	250.4	251.1	250.4
14	Pinnebog Wind Park	Installed Capacity	**MW**	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
15		Generation	**1,000 MWh**	182.7	161.2	170.9	170.4	170.4	170.4	170.9	170.4
16	Pine River Wind Park	Installed Capacity	**MW**	161.3	161.3	161.3	161.3	161.3	161.3	161.3	161.3
17		Generation	**1,000 MWh**	420.1	345.2	346.8	392.4	392.4	392.4	393.4	392.4
18	Polaris Wind Park	Installed Capacity	**MW**	168.6	168.6	168.6	168.6	168.6	168.6	168.6	168.6
19		Generation	**1,000 MWh**	498.9	412.9	415.5	465.8	465.8	465.8	467.1	465.8
20	Meridian	Installed Capacity	**MW**	224.9	224.9	224.9	224.9	224.9	224.9	224.9	224.9
21		Generation	**1,000 MWh**	238.7	418.6	564.1	562.6	562.6	562.6	564.1	562.6
22	Isabella I	Installed Capacity	**MW**	200.2	200.2	200.2	200.2	200.2	200.2	200.2	200.2
23		Generation	**1,000 MWh**	371.0	330.9	452.3	451.1	451.1	451.1	452.3	451.1
24	Isabella II	Installed Capacity	**MW**	183.3	183.3	183.3	183.3	183.3	183.3	183.3	183.3
25		Generation	**1,000 MWh**	409.0	344.8	414.1	413.0	413.0	413.0	414.1	413.0
26	Fairbanks	Installed Capacity	**MW**	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
27		Generation	**1,000 MWh**	214.5	193.7	193.1	192.6	192.6	192.6	193.1	192.6
28	Big Turtle II	Installed Capacity	**MW**	-	29.4	29.4	29.4	29.4	29.4	29.4	29.4
29		Generation	**1,000 MWh**	-	62.1	94.7	94.4	94.4	103.0	103.0	103.0
30	2028 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	140.0	140.0
31		Generation	**1,000 MWh**	-	-	-	-	-	-	308.3	368.9
32	2029 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	140.0
33		Generation	**1,000 MWh**	-	-	-	-	-	-	-	309.7
34	2030 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
35		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
36	2031 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
37		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
38	2032 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
39		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
40	2033 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
41		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
42	2034 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
43		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
44	2035 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
45		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
46	2036 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
47		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
48	2037 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
49		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
50	2038 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
51		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
52	2039 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
53		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
54	2040 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
55		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
56	2041 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
57		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
58	2042 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
59		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
60	MIGreenPower Subscribed Wind	Subscribed Capacity	**MW**	-	-	-	-	-	-	-	-
61		Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
62	VGP Subscribed Wind	Subscribed Capacity	**MW**	(456.0)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)
63		Subscribed Generation	**1,000 MWh**	(930.7)	(931.4)	(1,154.2)	(1,151.0)	(1,151.0)	(1,159.7)	(1,162.6)	(1,159.7)

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Generation from DTE Electric Renewable Energy Facilities

Case No.: U-21662
Exhibit: A-3
Witness: K.L. Bilyeu

Line No.	(a)	(b)	(c)	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037
1	**DTE Electric Owned**										
2	Gratiot County Wind	Installed Capacity	**MW**	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
3		Generation	**1,000 MWh**	231.4	231.4	232.1	231.4	231.4	231.4	232.1	231.4
4	Minden Wind Park	Installed Capacity	**MW**	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
5		Generation	**1,000 MWh**	112.9	112.9	113.2	112.9	112.9	112.9	113.2	112.9
6	McKinley Wind Park	Installed Capacity	**MW**	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
7		Generation	**1,000 MWh**	51.8	51.8	52.0	51.8	51.8	51.8	52.0	51.8
8	Sigel Wind Park	Installed Capacity	**MW**	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
9		Generation	**1,000 MWh**	249.4	249.4	250.1	249.4	249.4	249.4	250.1	249.4
10	Echo Wind Park	Installed Capacity	**MW**	112.0	112.0	112.0	112.0	112.0	112.0	112.0	112.0
11		Generation	**1,000 MWh**	387.9	387.9	388.9	387.9	387.9	387.9	388.9	387.9
12	Brookfield Wind Park	Installed Capacity	**MW**	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
13		Generation	**1,000 MWh**	250.4	250.4	251.1	250.4	250.4	250.4	251.1	250.4
14	Pinnebog Wind Park	Installed Capacity	**MW**	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
15		Generation	**1,000 MWh**	170.4	170.4	170.9	170.4	170.4	170.4	170.9	170.4
16	Pine River Wind Park	Installed Capacity	**MW**	161.3	161.3	161.3	161.3	161.3	161.3	161.3	161.3
17		Generation	**1,000 MWh**	392.4	392.4	393.4	392.4	392.4	392.4	393.4	392.4
18	Polaris Wind Park	Installed Capacity	**MW**	168.6	168.6	168.6	168.6	168.6	168.6	168.6	168.6
19		Generation	**1,000 MWh**	465.8	465.8	467.1	465.8	465.8	465.8	467.1	465.8
20	Meridian	Installed Capacity	**MW**	224.9	224.9	224.9	224.9	224.9	224.9	224.9	224.9
21		Generation	**1,000 MWh**	562.6	562.6	564.1	562.6	562.6	562.6	564.1	562.6
22	Isabella I	Installed Capacity	**MW**	200.2	200.2	200.2	200.2	200.2	200.2	200.2	200.2
23		Generation	**1,000 MWh**	451.1	451.1	452.3	451.1	451.1	451.1	452.3	451.1
24	Isabella II	Installed Capacity	**MW**	183.3	183.3	183.3	183.3	183.3	183.3	183.3	183.3
25		Generation	**1,000 MWh**	413.0	413.0	414.1	413.0	413.0	413.0	414.1	413.0
26	Fairbanks	Installed Capacity	**MW**	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
27		Generation	**1,000 MWh**	192.6	192.6	193.1	192.6	192.6	192.6	193.1	192.6
28	Big Turtle II	Installed Capacity	**MW**	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
29		Generation	**1,000 MWh**	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
30	2028 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
31		Generation	**1,000 MWh**	368.9	368.9	369.9	368.9	368.9	368.9	369.9	368.9
32	2029 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
33		Generation	**1,000 MWh**	371.6	371.6	372.6	371.6	371.6	371.6	372.6	371.6
34	2030 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
35		Generation	**1,000 MWh**	311.9	374.3	375.3	374.3	374.3	374.3	375.3	374.3
36	2031 IRP Build Wind	Installed Capacity	**MW**	-	200.0	200.0	200.0	200.0	200.0	200.0	200.0
37		Generation	**1,000 MWh**	-	446.0	536.6	535.2	535.2	535.2	536.6	535.2
38	2032 IRP Build Wind	Installed Capacity	**MW**	-	-	200.0	200.0	200.0	200.0	200.0	200.0
39		Generation	**1,000 MWh**	-	-	447.6	535.6	535.6	535.6	537.1	535.6
40	2033 IRP Build Wind	Installed Capacity	**MW**	-	-	-	200.0	200.0	200.0	200.0	200.0
41		Generation	**1,000 MWh**	-	-	-	446.7	536.0	536.0	537.5	536.0
42	2034 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	200.0	200.0	200.0	200.0
43		Generation	**1,000 MWh**	-	-	-	-	447.1	536.5	537.9	536.5
44	2035 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	1,000.0	1,000.0	1,000.0
45		Generation	**1,000 MWh**	-	-	-	-	-	2,237.1	2,691.8	2,684.5
46	2036 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	1,000.0	1,000.0
47		Generation	**1,000 MWh**	-	-	-	-	-	-	2,245.0	2,686.7
48	2037 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	1,000.0
49		Generation	**1,000 MWh**	-	-	-	-	-	-	-	2,240.7
50	2038 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
51		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
52	2039 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
53		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
54	2040 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
55		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
56	2041 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
57		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
58	2042 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
59		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
60	MIGreenPower Subscribed Wind	Subscribed Capacity	**MW**	-	-	-	-	-	-	-	-
61		Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
62	VGP Subscribed Wind	Subscribed Capacity	**MW**	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)
63		Subscribed Generation	**1,000 MWh**	(1,159.7)	(1,159.7)	(1,162.6)	(1,159.7)	(1,159.7)	(1,159.7)	(1,162.6)	(1,159.7)

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Generation from DTE Electric Renewable Energy Facilities

Case No.: U-21662
Exhibit: A-3
Witness: K.L. Bilyeu
Page: 3 of 6

Line No.	(a)	(b)	(c)	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
1	**DTE Electric Owned**										
2	Gratiot County Wind	Installed Capacity	**MW**	102.4	102.4	102.4	102.4	102.4	102.4	102.4	102.4
3		Generation	**1,000 MWh**	231.4	231.4	232.1	231.4	231.4	231.4	232.1	231.4
4	Minden Wind Park	Installed Capacity	**MW**	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
5		Generation	**1,000 MWh**	112.9	112.9	113.2	112.9	112.9	112.9	113.2	112.9
6	McKinley Wind Park	Installed Capacity	**MW**	14.4	14.4	14.4	14.4	14.4	14.4	14.4	14.4
7		Generation	**1,000 MWh**	51.8	51.8	52.0	51.8	51.8	51.8	52.0	51.8
8	Sigel Wind Park	Installed Capacity	**MW**	64.0	64.0	64.0	64.0	64.0	64.0	64.0	64.0
9		Generation	**1,000 MWh**	249.4	249.4	250.1	249.4	249.4	249.4	250.1	249.4
10	Echo Wind Park	Installed Capacity	**MW**	112.0	112.0	112.0	112.0	112.0	112.0	112.0	112.0
11		Generation	**1,000 MWh**	387.9	387.9	388.9	387.9	387.9	387.9	388.9	387.9
12	Brookfield Wind Park	Installed Capacity	**MW**	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
13		Generation	**1,000 MWh**	250.4	250.4	251.1	250.4	250.4	250.4	251.1	250.4
14	Pinnebog Wind Park	Installed Capacity	**MW**	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
15		Generation	**1,000 MWh**	170.4	170.4	170.9	170.4	170.4	170.4	170.9	170.4
16	Pine River Wind Park	Installed Capacity	**MW**	161.3	161.3	161.3	161.3	161.3	161.3	161.3	161.3
17		Generation	**1,000 MWh**	392.4	392.4	393.4	392.4	392.4	392.4	393.4	392.4
18	Polaris Wind Park	Installed Capacity	**MW**	168.6	168.6	168.6	168.6	168.6	168.6	168.6	168.6
19		Generation	**1,000 MWh**	465.8	465.8	467.1	465.8	465.8	465.8	467.1	465.8
20	Meridian	Installed Capacity	**MW**	224.9	224.9	224.9	224.9	224.9	224.9	224.9	224.9
21		Generation	**1,000 MWh**	562.6	562.6	564.1	562.6	562.6	562.6	564.1	562.6
22	Isabella I	Installed Capacity	**MW**	200.2	200.2	200.2	200.2	200.2	200.2	200.2	200.2
23		Generation	**1,000 MWh**	451.1	451.1	452.3	451.1	451.1	451.1	452.3	451.1
24	Isabella II	Installed Capacity	**MW**	183.3	183.3	183.3	183.3	183.3	183.3	183.3	183.3
25		Generation	**1,000 MWh**	413.0	413.0	414.1	413.0	413.0	413.0	414.1	413.0
26	Fairbanks	Installed Capacity	**MW**	72.5	72.5	72.5	72.5	72.5	72.5	72.5	72.5
27		Generation	**1,000 MWh**	192.6	192.6	193.1	192.6	192.6	192.6	193.1	192.6
28	Big Turtle II	Installed Capacity	**MW**	29.4	29.4	29.4	29.4	29.4	29.4	29.4	29.4
29		Generation	**1,000 MWh**	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
30	2028 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
31		Generation	**1,000 MWh**	368.9	368.9	369.9	368.9	368.9	368.9	369.9	368.9
32	2029 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
33		Generation	**1,000 MWh**	371.6	371.6	372.6	371.6	371.6	371.6	372.6	371.6
34	2030 IRP Build Wind	Installed Capacity	**MW**	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
35		Generation	**1,000 MWh**	374.3	374.3	375.3	374.3	374.3	374.3	375.3	374.3
36	2031 IRP Build Wind	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
37		Generation	**1,000 MWh**	535.2	535.2	536.6	535.2	535.2	535.2	536.6	535.2
38	2032 IRP Build Wind	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
39		Generation	**1,000 MWh**	535.6	535.6	537.1	535.6	535.6	535.6	537.1	535.6
40	2033 IRP Build Wind	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
41		Generation	**1,000 MWh**	536.0	536.0	537.5	536.0	536.0	536.0	537.5	536.0
42	2034 IRP Build Wind	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
43		Generation	**1,000 MWh**	536.5	536.5	537.9	536.5	536.5	536.5	537.9	536.5
44	2035 IRP Build Wind	Installed Capacity	**MW**	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
45		Generation	**1,000 MWh**	2,684.5	2,684.5	2,691.8	2,684.5	2,684.5	2,684.5	2,691.8	2,684.5
46	2036 IRP Build Wind	Installed Capacity	**MW**	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
47		Generation	**1,000 MWh**	2,686.7	2,686.7	2,694.0	2,686.7	2,686.7	2,686.7	2,694.0	2,686.7
48	2037 IRP Build Wind	Installed Capacity	**MW**	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
49		Generation	**1,000 MWh**	2,688.8	2,688.8	2,696.2	2,688.8	2,688.8	2,688.8	2,696.2	2,688.8
50	2038 IRP Build Wind	Installed Capacity	**MW**	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
51		Generation	**1,000 MWh**	2,242.5	2,691.0	2,698.3	2,691.0	2,691.0	2,691.0	2,698.3	2,691.0
52	2039 IRP Build Wind	Installed Capacity	**MW**	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
53		Generation	**1,000 MWh**	-	2,244.3	2,700.5	2,693.1	2,693.1	2,693.1	2,700.5	2,693.1
54	2040 IRP Build Wind	Installed Capacity	**MW**	-	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
55		Generation	**1,000 MWh**	-	-	2,252.2	2,695.3	2,695.3	2,695.3	2,702.7	2,695.3
56	2041 IRP Build Wind	Installed Capacity	**MW**	-	-	-	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
57		Generation	**1,000 MWh**	-	-	-	2,247.9	2,697.5	2,697.5	2,704.8	2,697.5
58	2042 IRP Build Wind	Installed Capacity	**MW**	-	-	-	-	500.0	500.0	500.0	500.0
59		Generation	**1,000 MWh**	-	-	-	-	1,124.8	1,349.8	1,353.5	1,349.8
60	MIGreenPower Subscribed Wind	Subscribed Capacity	**MW**	-	-	-	-	-	-	-	-
61		Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
62	VGP Subscribed Wind	Subscribed Capacity	**MW**	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)	(485.4)
63		Subscribed Generation	**1,000 MWh**	(1,159.7)	(1,159.7)	(1,162.6)	(1,159.7)	(1,159.7)	(1,159.7)	(1,162.6)	(1,159.7)

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Line No.	(a)	(b)	(c)	(d) Prelim 2022	(e) Prelim 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029
	DTE Electric Owned										
64	DTE Solar Currents I	Installed Capacity	**MW**	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
65		Generation	**1,000 MWh**	13.8	12.7	13.8	13.7	13.6	13.5	13.5	13.4
66	DTE Solar Currents II	Installed Capacity	**MW**	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
67		Generation	**1,000 MWh**	1.5	1.4	1.4	1.3	1.3	1.3	1.3	1.3
68	Demille/Turrill/O'Shea Utility-Scale Solar	Installed Capacity	**MW**	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3
69		Generation	**1,000 MWh**	66.3	64.6	66.7	66.2	65.8	65.5	65.3	64.8
70	Ford Rooftop Solar Pilot	Installed Capacity	**MW**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
71		Generation	**1,000 MWh**	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.8
72	2024 Future Solar Pilot	Installed Capacity	**MW**	-	-	10.0	10.0	10.0	10.0	10.0	10.0
73		Generation	**1,000 MWh**	-	-	3.2	19.8	19.7	19.6	19.5	19.4
74	Gratiot Solar	Installed Capacity	**MW**	-	-	-	-	50.0	50.0	50.0	50.0
75		Generation	**1,000 MWh**	-	-	-	-	92.3	94.5	94.6	94.6
76	Pine River Solar	Installed Capacity	**MW**	-	-	-	80.0	80.0	80.0	80.0	80.0
77		Generation	**1,000 MWh**	-	-	-	152.3	152.4	152.4	152.4	152.5
78	Polaris Solar	Installed Capacity	**MW**	-	-	-	100.0	100.0	100.0	100.0	100.0
79		Generation	**1,000 MWh**	-	-	-	173.5	186.1	186.1	186.1	186.2
80	Sauk Solar	Installed Capacity	**MW**	-	-	-	150.0	150.0	150.0	150.0	150.0
81		Generation	**1,000 MWh**	-	-	-	307.9	306.3	304.8	304.1	301.8
82	Wheeler Center - Customer Requested	Installed Capacity	**MW**	-	-	-	16.0	16.0	16.0	16.0	16.0
83		Generation	**1,000 MWh**	-	-	-	27.6	27.4	27.3	27.2	27.0
84	Ford I - 2024 - Customer Requested - Pt 1	Installed Capacity	**MW**	-	-	-	-	-	198.0	198.0	198.0
85		Generation	**1,000 MWh**	-	-	-	-	-	396.4	424.0	420.7
86	Ford I - 2024 - Customer Requested - Pt 2	Installed Capacity	**MW**	-	-	-	-	100.0	100.0	100.0	100.0
87		Generation	**1,000 MWh**	-	-	-	-	98.8	198.3	197.8	196.3
88	Ford II - 2025 - Customer Requested - Pt 1	Installed Capacity	**MW**	-	-	-	-	125.0	125.0	125.0	125.0
89		Generation	**1,000 MWh**	-	-	-	-	71.6	274.6	273.9	271.8
86	Ford II - 2025 - Customer Requested - Pt 2	Installed Capacity	**MW**	-	-	-	-	-	200.0	200.0	200.0
87		Generation	**1,000 MWh**	-	-	-	-	-	424.4	454.0	450.5
88	2027 Project 1 - Customer Requested	Installed Capacity	**MW**	-	-	-	-	-	-	200.0	200.0
89		Generation	**1,000 MWh**	-	-	-	-	-	-	244.3	392.0
90	Unnamed - 2025 - Customer Requested	Installed Capacity	**MW**	-	-	-	-	-	165.0	165.0	165.0
91		Generation	**1,000 MWh**	-	-	-	-	-	349.8	349.0	346.3
92	2028 Project 1 - Customer Requested	Installed Capacity	**MW**	-	-	-	-	-	-	-	200.0
93		Generation	**1,000 MWh**	-	-	-	-	-	-	-	396.5
94	Unknown Approved - Unnamed - Customer Requested	Installed Capacity	**MW**	-	-	-	-	-	119.0	119.0	119.0
95		Generation	**1,000 MWh**	-	-	-	-	-	232.9	232.4	230.6
96	Fish Creek	Installed Capacity	**MW**	-	-	-	-	132.0	132.0	132.0	132.0
97		Generation	**1,000 MWh**	-	-	-	-	239.3	255.3	254.7	252.8
98	Mission Rd	Installed Capacity	**MW**	-	-	-	-	158.0	158.0	158.0	158.0
99		Generation	**1,000 MWh**	-	-	-	-	286.1	305.2	304.5	302.1
100	Little Trout	Installed Capacity	**MW**	-	-	-	-	150.0	150.0	150.0	150.0
101		Generation	**1,000 MWh**	-	-	-	-	24.2	290.5	289.9	287.6
102	Cedar Fields	Installed Capacity	**MW**	-	-	-	-	-	137.6	137.6	137.6
103		Generation	**1,000 MWh**	-	-	-	-	-	171.4	276.6	274.5
104	2027 Unapproved - VGP	Installed Capacity	**MW**	-	-	-	-	-	200.0	200.0	200.0
105		Generation	**1,000 MWh**	-	-	-	-	-	365.1	390.4	387.4
106	2028 Unapproved - VGP	Installed Capacity	**MW**	-	-	-	-	-	-	334.0	334.0
107		Generation	**1,000 MWh**	-	-	-	-	-	-	615.4	654.5
108	2029 Unapproved - VGP	Installed Capacity	**MW**	-	-	-	-	-	-	-	87.0
109		Generation	**1,000 MWh**	-	-	-	-	-	-	-	160.9
110	2027 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	507.0	507.0	507.0
111		Generation	**1,000 MWh**	-	-	-	-	-	925.6	989.7	982.1
112	2028 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	280.0	280.0
113		Generation	**1,000 MWh**	-	-	-	-	-	-	515.9	548.7
114	2029 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	560.0
115		Generation	**1,000 MWh**	-	-	-	-	-	-	-	1,035.7
116	2030 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
117		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
118	2031 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
119		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
120	2032 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
121		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
122	2033 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
123		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
124	2034 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
125		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
126	2042 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
127		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
128	MIGreenPower Subscribed Solar	Subscribed Capacity	**MW**	(13.4)	-	-	-	-	-	-	-
129		Subscribed Generation	**1,000 MWh**	(17.7)	-	-	-	-	-	-	-
130	VGP Subscribed Solar	Subscribed Capacity	**MW**	-	-	-	(346.0)	(1,061.0)	(1,943.0)	(2,477.0)	(2,764.0)
131		Subscribed Generation	**1,000 MWh**	-	-	-	(661.3)	(1,484.5)	(3,857.6)	(4,794.7)	(5,512.0)
132	Total Wind Generation (excluding VGPs)		**1,000 MWh**	2,754	2,484	2,785	2,875	2,875	2,875	3,191	3,554
133	Total Solar Generation (excluding VGPs)		**1,000 MWh**	65	80	86	102	101	1,198	1,883	2,941
134	Total Generation (excluding VGPs)		**1,000 MWh**	2,819	2,564	2,871	2,977	2,976	4,073	5,074	6,494

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	DTE Electric Owned										
64	DTE Solar Currents I	Installed Capacity	**MW**	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
65		Generation	**1,000 MWh**	13.3	13.3	13.2	13.1	13.1	13.0	13.0	12.9
66	DTE Solar Currents II	Installed Capacity	**MW**	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
67		Generation	**1,000 MWh**	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
68	Demille/Turrill/O'Shea Utility-Scale Solar	Installed Capacity	**MW**	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3
69		Generation	**1,000 MWh**	64.5	64.2	64.0	63.6	63.2	62.9	62.8	62.3
70	Ford Rooftop Solar Pilot	Installed Capacity	**MW**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
71		Generation	**1,000 MWh**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
72	2024 Future Solar Pilot	Installed Capacity	**MW**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
73		Generation	**1,000 MWh**	19.3	19.2	19.2	19.0	18.9	18.8	18.8	18.6
74	Gratiot Solar	Installed Capacity	**MW**	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
75		Generation	**1,000 MWh**	94.6	94.7	94.7	94.7	94.7	94.7	94.8	94.8
76	Pine River Solar	Installed Capacity	**MW**	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
77		Generation	**1,000 MWh**	152.5	152.5	152.5	152.6	152.6	152.6	152.6	152.6
78	Polaris Solar	Installed Capacity	**MW**	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
79		Generation	**1,000 MWh**	186.2	186.2	186.2	186.3	186.3	186.3	186.3	186.3
80	Sauk Solar	Installed Capacity	**MW**	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
81		Generation	**1,000 MWh**	300.3	298.7	298.1	295.8	294.3	292.8	292.2	289.9
82	Wheeler Center - Customer Requested	Installed Capacity	**MW**	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
83		Generation	**1,000 MWh**	26.9	26.7	26.7	26.5	26.3	26.2	26.1	25.9
84	Ford I - 2024 - Customer Requested - Pt 1	Installed Capacity	**MW**	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0
85		Generation	**1,000 MWh**	418.6	416.5	415.6	412.4	410.3	408.2	407.3	404.2
86	Ford I - 2024 - Customer Requested - Pt 2	Installed Capacity	**MW**	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
87		Generation	**1,000 MWh**	195.3	194.4	193.9	192.4	191.5	190.5	190.1	188.6
88	Ford II - 2025 - Customer Requested - Pt 1	Installed Capacity	**MW**	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
89		Generation	**1,000 MWh**	270.5	269.1	268.5	266.4	265.1	263.8	263.2	261.1
86	Ford II - 2025 - Customer Requested - Pt 2	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
87		Generation	**1,000 MWh**	448.2	446.0	444.9	441.5	439.3	437.1	436.1	432.7
88	2027 Project 1 - Customer Requested	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
89		Generation	**1,000 MWh**	390.0	388.1	387.2	384.2	382.3	380.4	379.5	376.6
90	Unnamed - 2025 - Customer Requested	Installed Capacity	**MW**	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
91		Generation	**1,000 MWh**	344.6	342.8	342.1	339.4	337.7	336.0	335.3	332.7
92	2028 Project 1 - Customer Requested	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
93		Generation	**1,000 MWh**	394.5	392.6	391.7	388.7	386.7	384.8	383.9	380.9
94	Unknown Approved - Unnamed - Customer Requested	Installed Capacity	**MW**	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0
95		Generation	**1,000 MWh**	229.4	228.3	227.7	226.0	224.9	223.7	223.2	221.5
96	Fish Creek	Installed Capacity	**MW**	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0
97		Generation	**1,000 MWh**	251.5	250.2	249.7	247.7	246.5	245.3	244.7	242.8
98	Mission Rd	Installed Capacity	**MW**	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
99		Generation	**1,000 MWh**	300.6	299.1	298.4	296.1	294.7	293.2	292.5	290.3
100	Little Trout	Installed Capacity	**MW**	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
101		Generation	**1,000 MWh**	286.2	284.7	284.1	281.9	280.5	279.1	278.5	276.3
102	Cedar Fields	Installed Capacity	**MW**	137.6	137.6	137.6	137.6	137.6	137.6	137.6	137.6
103		Generation	**1,000 MWh**	273.1	271.7	271.1	269.0	267.7	266.3	265.7	263.7
104	2027 Unapproved - VGP	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
105		Generation	**1,000 MWh**	385.5	383.6	382.7	379.7	377.8	375.9	375.1	372.2
106	2028 Unapproved - VGP	Installed Capacity	**MW**	334.0	334.0	334.0	334.0	334.0	334.0	334.0	334.0
107		Generation	**1,000 MWh**	651.2	648.0	646.5	641.5	638.3	635.1	633.7	628.8
108	2029 Unapproved - VGP	Installed Capacity	**MW**	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
109		Generation	**1,000 MWh**	171.6	170.7	170.3	169.0	168.2	167.3	167.0	165.7
110	2027 IRP Build Solar	Installed Capacity	**MW**	507.0	507.0	507.0	507.0	507.0	507.0	507.0	507.0
111		Generation	**1,000 MWh**	977.2	972.3	970.1	962.6	957.8	953.0	950.8	943.5
112	2028 IRP Build Solar	Installed Capacity	**MW**	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
113		Generation	**1,000 MWh**	545.9	543.2	542.0	537.8	535.1	532.4	531.2	527.1
114	2029 IRP Build Solar	Installed Capacity	**MW**	560.0	560.0	560.0	560.0	560.0	560.0	560.0	560.0
115		Generation	**1,000 MWh**	1,104.5	1,099.0	1,096.5	1,088.0	1,082.6	1,077.2	1,074.7	1,066.4
116	2030 IRP Build Solar	Installed Capacity	**MW**	560.0	560.0	560.0	560.0	560.0	560.0	560.0	560.0
117		Generation	**1,000 MWh**	1,042.4	1,111.6	1,109.1	1,100.6	1,095.1	1,089.6	1,087.1	1,078.7
118	2031 IRP Build Solar	Installed Capacity	**MW**	-	800.0	800.0	800.0	800.0	800.0	800.0	800.0
119		Generation	**1,000 MWh**	-	1,498.7	1,602.6	1,590.3	1,582.3	1,574.4	1,570.8	1,558.7
120	2032 IRP Build Solar	Installed Capacity	**MW**	-	-	400.0	400.0	400.0	400.0	400.0	400.0
121		Generation	**1,000 MWh**	-	-	756.2	804.2	800.2	796.2	794.4	788.3
122	2033 IRP Build Solar	Installed Capacity	**MW**	-	-	-	800.0	800.0	800.0	800.0	800.0
123		Generation	**1,000 MWh**	-	-	-	1,517.9	1,618.7	1,610.6	1,606.9	1,594.5
124	2034 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	800.0	800.0	800.0	800.0
125		Generation	**1,000 MWh**	-	-	-	-	1,527.4	1,628.9	1,625.2	1,612.6
126	2042 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	-	-	-	-
127		Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
128	MIGreenPower Subscribed Solar	Subscribed Capacity	**MW**	-	-	-	-	-	-	-	-
129		Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
130	VGP Subscribed Solar	Subscribed Capacity	**MW**	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)
131		Subscribed Generation	**1,000 MWh**	(5,498.2)	(5,473.0)	(5,461.6)	(5,422.8)	(5,397.9)	(5,373.1)	(5,362.0)	(5,323.9)
132	Total Wind Generation (excluding VGPs)		**1,000 MWh**	3,927	4,436	4,985	5,507	6,044	8,370	11,087	13,745
133	Total Solar Generation (excluding VGPs)		**1,000 MWh**	4,042	5,595	6,446	7,968	9,564	9,625	9,604	9,529
134	Total Generation (excluding VGPs)		**1,000 MWh**	7,970	10,031	11,431	13,476	15,608	17,996	20,690	23,274

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Generation from DTE Electric Renewable Energy Facilities

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Line No.	(a)	(b)	(c)	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	DTE Electric Owned										
64	DTE Solar Currents I	Installed Capacity	**MW**	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
65		Generation	**1,000 MWh**	12.8	12.8	12.7	12.6	12.6	12.5	12.5	12.4
66	DTE Solar Currents II	Installed Capacity	**MW**	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
67		Generation	**1,000 MWh**	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
68	Demille/Turrill/O'Shea Utility-Scale Solar	Installed Capacity	**MW**	50.3	50.3	50.3	50.3	50.3	50.3	50.3	50.3
69		Generation	**1,000 MWh**	62.0	61.7	61.5	61.1	60.8	60.4	60.3	59.8
70	Ford Rooftop Solar Pilot	Installed Capacity	**MW**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
71		Generation	**1,000 MWh**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
72	2024 Future Solar Pilot	Installed Capacity	**MW**	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
73		Generation	**1,000 MWh**	18.5	18.4	18.4	18.3	18.2	18.1	18.0	17.9
74	Gratiot Solar	Installed Capacity	**MW**	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
75		Generation	**1,000 MWh**	94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8
76	Pine River Solar	Installed Capacity	**MW**	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
77		Generation	**1,000 MWh**	152.6	152.6	152.6	152.6	152.6	152.6	152.5	152.5
78	Polaris Solar	Installed Capacity	**MW**	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
79		Generation	**1,000 MWh**	186.3	186.3	186.3	186.3	186.3	186.3	186.2	186.2
80	Sauk Solar	Installed Capacity	**MW**	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
81		Generation	**1,000 MWh**	288.4	287.0	286.4	284.1	282.7	281.3	280.7	278.5
82	Wheeler Center - Customer Requested	Installed Capacity	**MW**	16.0	16.0	16.0	16.0	16.0	16.0	16.0	16.0
83		Generation	**1,000 MWh**	25.8	25.7	25.6	25.4	25.3	25.2	25.1	24.9
84	Ford I - 2024 - Customer Requested - Pt 1	Installed Capacity	**MW**	198.0	198.0	198.0	198.0	198.0	198.0	198.0	198.0
85		Generation	**1,000 MWh**	402.2	400.1	399.2	396.1	394.2	392.2	391.3	388.3
86	Ford I - 2024 - Customer Requested - Pt 2	Installed Capacity	**MW**	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
87		Generation	**1,000 MWh**	187.7	186.7	186.3	184.9	183.9	183.0	182.6	181.2
88	Ford II - 2025 - Customer Requested - Pt 1	Installed Capacity	**MW**	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
89		Generation	**1,000 MWh**	259.8	258.5	257.9	256.0	254.7	253.4	252.8	250.9
86	Ford II - 2025 - Customer Requested - Pt 2	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
87		Generation	**1,000 MWh**	430.6	428.4	427.5	424.2	422.0	419.9	419.0	415.7
88	2027 Project 1 - Customer Requested	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
89		Generation	**1,000 MWh**	374.7	372.8	372.0	369.1	367.3	365.4	364.6	361.8
90	Unnamed - 2025 - Customer Requested	Installed Capacity	**MW**	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
91		Generation	**1,000 MWh**	331.0	329.4	328.6	326.1	324.5	322.8	322.1	319.6
92	2028 Project 1 - Customer Requested	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
93		Generation	**1,000 MWh**	379.0	377.1	376.3	373.4	371.5	369.7	368.8	366.0
94	Unknown Approved - Unnamed - Customer Requested	Installed Capacity	**MW**	119.0	119.0	119.0	119.0	119.0	119.0	119.0	119.0
95		Generation	**1,000 MWh**	220.4	219.3	218.8	217.1	216.0	214.9	214.4	212.8
96	Fish Creek	Installed Capacity	**MW**	132.0	132.0	132.0	132.0	132.0	132.0	132.0	132.0
97		Generation	**1,000 MWh**	241.6	240.4	239.9	238.0	236.8	235.6	235.1	233.3
98	Mission Rd	Installed Capacity	**MW**	158.0	158.0	158.0	158.0	158.0	158.0	158.0	158.0
99		Generation	**1,000 MWh**	288.8	287.4	286.7	284.5	283.1	281.7	281.0	278.8
100	Little Trout	Installed Capacity	**MW**	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0
101		Generation	**1,000 MWh**	274.9	273.6	272.9	270.8	269.5	268.1	267.5	265.4
102	Cedar Fields	Installed Capacity	**MW**	137.6	137.6	137.6	137.6	137.6	137.6	137.6	137.6
103		Generation	**1,000 MWh**	262.4	261.1	260.5	258.4	257.2	255.9	255.3	253.3
104	2027 Unapproved - VGP	Installed Capacity	**MW**	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
105		Generation	**1,000 MWh**	370.3	368.5	367.6	364.8	363.0	361.2	360.3	357.6
106	2028 Unapproved - VGP	Installed Capacity	**MW**	334.0	334.0	334.0	334.0	334.0	334.0	334.0	334.0
107		Generation	**1,000 MWh**	625.6	622.5	621.1	616.3	613.2	610.1	608.8	604.1
108	2029 Unapproved - VGP	Installed Capacity	**MW**	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
109		Generation	**1,000 MWh**	164.8	164.0	163.7	162.4	161.6	160.8	160.4	159.2
110	2027 IRP Build Solar	Installed Capacity	**MW**	507.0	507.0	507.0	507.0	507.0	507.0	507.0	507.0
111		Generation	**1,000 MWh**	938.8	934.1	932.0	924.8	920.2	915.5	913.5	906.4
112	2028 IRP Build Solar	Installed Capacity	**MW**	280.0	280.0	280.0	280.0	280.0	280.0	280.0	280.0
113		Generation	**1,000 MWh**	524.5	521.9	520.7	516.7	514.1	511.5	510.3	506.4
114	2029 IRP Build Solar	Installed Capacity	**MW**	560.0	560.0	560.0	560.0	560.0	560.0	560.0	560.0
115		Generation	**1,000 MWh**	1,061.1	1,055.8	1,053.4	1,045.3	1,040.0	1,034.8	1,032.5	1,024.5
116	2030 IRP Build Solar	Installed Capacity	**MW**	560.0	560.0	560.0	560.0	560.0	560.0	560.0	560.0
117		Generation	**1,000 MWh**	1,073.3	1,067.9	1,065.5	1,057.3	1,052.0	1,046.7	1,044.4	1,036.3
118	2031 IRP Build Solar	Installed Capacity	**MW**	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
119		Generation	**1,000 MWh**	1,550.9	1,543.2	1,539.6	1,527.8	1,520.1	1,512.5	1,509.1	1,497.4
120	2032 IRP Build Solar	Installed Capacity	**MW**	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
121		Generation	**1,000 MWh**	784.3	780.4	778.6	772.6	768.8	764.9	763.2	757.3
122	2033 IRP Build Solar	Installed Capacity	**MW**	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
123		Generation	**1,000 MWh**	1,586.5	1,578.6	1,575.0	1,562.9	1,555.0	1,547.3	1,543.7	1,531.8
124	2034 IRP Build Solar	Installed Capacity	**MW**	800.0	800.0	800.0	800.0	800.0	800.0	800.0	800.0
125		Generation	**1,000 MWh**	1,604.6	1,596.5	1,592.9	1,580.6	1,572.7	1,564.8	1,561.3	1,549.2
126	2042 IRP Build Solar	Installed Capacity	**MW**	-	-	-	-	500.0	500.0	500.0	500.0
127		Generation	**1,000 MWh**	-	-	-	-	882.9	1,054.1	1,051.7	1,043.6
128	MIGreenPower Subscribed Solar	Subscribed Capacity	**MW**	-	-	-	-	-	-	-	-
129		Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-
130	VGP Subscribed Solar	Subscribed Capacity	**MW**	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)	(2,764.0)
131		Subscribed Generation	**1,000 MWh**	(5,299.5)	(5,275.2)	(5,264.2)	(5,226.9)	(5,202.9)	(5,179.0)	(5,168.2)	(5,131.6)
132	Total Wind Generation (excluding VGPs)		**1,000 MWh**	16,436	19,128	21,883	24,520	26,095	26,320	26,392	26,320
133	Total Solar Generation (excluding VGPs)		**1,000 MWh**	9,482	9,434	9,413	9,340	10,176	10,301	10,278	10,198
134	Total Generation (excluding VGPs)		**1,000 MWh**	25,917	28,563	31,296	33,861	36,271	36,621	36,670	36,518

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Forecasted Renewable Energy Credit Balance and Transactions

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Line No.	(a)	(b)	(c) Prelim 2022	(d) Prelim 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027	(i) 2028	(j) 2029	(k) 2030	(l) 2031	(m) 2032	(n) 2033
1	Beginning Balance of RECs	**1,000 RECs**	4,839	3,928	2,806	8,481	8,276	8,656	11,226	15,803	22,885	21,598	22,556	24,632
2	Beginning Balance of ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
3	PURPA RECs (less non-jurisdictional)	**1,000 RECs**	194	180	180	180	180	180	180	180	180	180	180	180
4	REC-only Contracts	**1,000 RECs**	-	336	293	289	283	276	256	249	810	812	817	824
5	Purchase of RECs (PPA Contracts)	**1,000 RECs**	1,518	1,343	1,578	1,600	2,053	2,639	3,029	3,632	4,185	4,098	3,799	3,412
6	Purchase of RECs (SolarCurrents)	**1,000 RECs**	2	1	1	1	1	1	1	1	1	1	1	1
7	Generation of RECs	**1,000 RECs**	2,819	2,587	2,871	2,977	2,976	4,073	5,074	6,494	7,970	10,031	11,431	13,476
8	Generation of ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
9	Michigan Incentive RECs	**1,000 RECs**	464	480	529	532	553	919	1,148	1,501	1,758	2,074	2,186	2,455
10	Transferred GreenCurrents RECs/MIGP RECs	**1,000 RECs**	-	(180)	-	-	-	-	-	-	-	-	-	-
11	Total Available RECs	**1,000 RECs**	10,094	9,077	8,259	14,061	14,323	16,744	20,914	27,861	37,789	38,794	40,970	44,980
12	Total Available ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
13	Expected RECs to be Consumed	**1,000 RECs**	(6,166)	(6,091)	(5,647)	(5,784)	(5,668)	(5,518)	(5,111)	(4,976)	(16,191)	(16,239)	(16,337)	(16,485)
14	Expected ACECs to be Consumed	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
15	Expired RECs	**1,000 RECs**	-	-	-	-	-	-	-	-	-	-	-	-
16	Expired ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
17	Ending REC Balance	**1,000 RECs**	3,928	2,806	8,481	8,276	8,656	11,226	15,803	22,885	21,598	22,556	24,632	28,495
18	Ending ACEC Balance	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
19	Beginning Balance of EWR Credits	**1,000 EOCs/RECs**	229	258	222	-	-	-	-	-	-	-	-	-
20	Transferred EWR Credits	**1,000 EOCs/RECs**	258	222	-	-	-	-	-	-	-	-	-	-
21	Expected EWR Credits to be Consumed	**1,000 EOCs/RECs**	(229)	(258)	(222)	-	-	-	-	-	-	-	-	-
22	Excess EWR Credits	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-
23	Ending Balance EWR Credits	**1,000 EOCs/RECs**	258	222	-	-	-	-	-	-	-	-	-	-

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Line No.	(a)	(b)	(o) 2034	(p) 2035	(q) 2036	(r) 2037	(s) 2038	(t) 2039	(u) 2040	(v) 2041	(w) 2042	(x) 2043	(y) 2044	(z) 2045
1	Beginning Balance of RECs	**1,000 RECs**	28,495	34,051	38,655	45,804	55,344	67,418	81,970	99,132	118,696	140,710	162,758	184,464
2	Beginning Balance of ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
3	PURPA RECs (less non-jurisdictional)	**1,000 RECs**	180	180	180	180	180	180	180	180	180	180	180	180
4	REC-only Contracts	**1,000 RECs**	830	1,007	1,018	1,029	1,035	1,043	1,049	1,056	1,058	1,063	1,069	1,077
5	Purchase of RECs (PPA Contracts)	**1,000 RECs**	2,846	2,768	2,764	2,745	2,734	2,723	2,719	2,700	2,689	2,678	2,674	2,656
6	Purchase of RECs (SolarCurrents)	**1,000 RECs**	1	1	1	1	1	1	1	1	1	1	1	1
7	Generation of RECs	**1,000 RECs**	15,608	17,996	20,690	23,274	25,917	28,563	31,296	33,861	36,271	36,621	36,670	36,518
8	Generation of ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
9	Michigan Incentive RECs	**1,000 RECs**	2,685	2,795	2,851	2,888	2,906	2,897	2,897	2,882	2,973	2,757	2,485	2,297
10	Transferred GreenCurrents RECs/MIGP RECs	**1,000 RECs**	-	-	-	-	-	-	-	-	-	-	-	-
11	Total Available RECs	**1,000 RECs**	50,645	58,798	66,159	75,921	88,118	102,825	120,113	139,811	161,868	184,011	205,837	227,193
12	Total Available ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
13	Expected RECs to be Consumed	**1,000 RECs**	(16,594)	(20,144)	(20,355)	(20,577)	(20,700)	(20,855)	(20,981)	(21,115)	(21,158)	(21,253)	(21,372)	(21,536)
14	Expected ACECs to be Consumed	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
15	Expired RECs	**1,000 RECs**	-	-	-	-	-	-	-	-	-	-	-	-
16	Expired ACECs	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
17	Ending REC Balance	**1,000 RECs**	34,051	38,655	45,804	55,344	67,418	81,970	99,132	118,696	140,710	162,758	184,464	205,657
18	Ending ACEC Balance	**1,000 ACECs**	-	-	-	-	-	-	-	-	-	-	-	-
19	Beginning Balance of EWR Credits	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-
20	Transferred EWR Credits	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-
21	Expected EWR Credits to be Consumed	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-
22	Excess EWR Credits	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-
23	Ending Balance EWR Credits	**1,000 EOCs/RECs**	-	-	-	-	-	-	-	-	-	-	-	-

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Line No.	(a)	(b)	(c) Prelim 2022	(d) Prelim 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027	(i) 2028	(j) 2029	(k) 2030	(l) 2031	(m) 2032	(n) 2033
1	Beginning Balance of RECs	**$Mil**	$ 2.0	$ 1.4	$ 1.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Beginning Balance of ACECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	PURPA RECs (less non-jurisdictional)	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Purchase of RECs (REC-only Contracts)	**$Mil**	$ -	$ 0.5	$ 0.9	$ 0.9	$ 0.9	$ 0.8	$ 0.8	$ 0.7	$ 4.0	$ 4.1	$ 4.1	$ 4.1
5	Purchase of RECs (SolarCurrents)	**$Mil**	$ 0.6	$ 0.6	$ 0.6	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5
6	Generation of RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Generation of ACECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Michigan Incentive RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Transferred GreenCurrents RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Purchase of RECs (PPA Contracts)	**$Mil**	$ 0.8	$ 0.3	$ 1.2	$ 1.2	$ 1.5	$ 1.9	$ 2.2	$ 2.7	$ 3.1	$ 3.0	$ 2.8	$ 2.5
11	Generation of RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.0	$ 2.0	$ 3.0	$ 4.0
12	Total Available RECs & ACECs	**$Mil**	$ 3.4	$ 2.8	$ 4.1	$ 2.6	$ 2.9	$ 3.3	$ 3.5	$ 3.9	$ 8.6	$ 9.6	$ 10.4	$ 11.1
13	Expected RECs & ACECs to be Consumed	**$Mil**	$ (2.0)	$ (1.3)	$ (4.1)	$ (2.6)	$ (2.9)	$ (3.3)	$ (3.5)	$ (3.9)	$ (8.6)	$ (9.6)	$ (10.4)	$ (11.1)
14	Ending Balance	**$Mil**	$ 1.4	$ 1.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Average Cost of Available RECs & ACECs	**$/REC**	$ 0.36	$ 0.52	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Forecasted Renewable Energy Credit Balance and Transactions

Case No.: U-21662
Exhibit: A-4
Witness: K.L. Bilyeu
Page: 4 of 4

Line No.	(a)	(b)	(o) 2034	(p) 2035	(q) 2036	(r) 2037	(s) 2038	(t) 2039	(u) 2040	(v) 2041	(w) 2042	(x) 2043	(y) 2044	(z) 2045
1	Beginning Balance of RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Beginning Balance of ACECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	PURPA RECs (less non-jurisdictional)	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Purchase of RECs (REC-only Contracts)	**$Mil**	$ 4.1	$ 5.0	$ 5.1	$ 5.1	$ 5.2	$ 5.2	$ 5.2	$ 5.3	$ 5.3	$ 5.3	$ 5.3	$ 5.4
5	Purchase of RECs (SolarCurrents)	**$Mil**	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5
6	Generation of RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Generation of ACECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Michigan Incentive RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Transferred GreenCurrents RECs	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Purchase of RECs (PPA Contracts)	**$Mil**	$ 2.1	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 2.0	$ 1.9
11	Generation of RECs	**$Mil**	$ 5.0	$ 6.0	$ 7.0	$ 8.0	$ 9.0	$ 10.0	$ 11.0	$ 12.0	$ 13.0	$ 14.0	$ 15.0	$ 16.0
12	Total Available RECs & ACECs	**$Mil**	$ 11.8	$ 13.6	$ 14.6	$ 15.7	$ 16.7	$ 17.7	$ 18.7	$ 19.8	$ 20.8	$ 21.8	$ 22.8	$ 23.8
13	Expected RECs & ACECs to be Consumed	**$Mil**	$ (11.8)	$ (13.6)	$ (14.6)	$ (15.7)	$ (16.7)	$ (17.7)	$ (18.7)	$ (19.8)	$ (20.8)	$ (21.8)	$ (22.8)	$ (23.8)
14	Ending Balance	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Total Average Cost of Available RECs & ACECs	**$/REC**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Assumptions for Forecasted Renewable Builds

Case No.: U-21662
Exhibit: A-5
Witness: K.L. Bilyeu
Page: 1 of 1

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Online Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
1	Solar Installed Cost ($/kW)	$ 1,754	$ 1,728	$ 1,698	$ 1,667	$ 1,634	$ 1,600	$ 1,562	$ 1,523	$ 1,481	$ 1,489	$ 1,497	$ 1,504	$ 1,511	$ 1,517	$ 1,523	$ 1,529	$ 1,534	$ 1,539	$ 1,543
2	Solar Capacity Factor (%)	22.3%	22.5%	22.6%	22.8%	22.9%	23.1%	23.2%	23.4%	23.5%	23.6%	23.7%	23.8%	23.9%	24.0%	24.1%	24.2%	24.3%	24.4%	24.5%
3	Wind Installed Cost ($/kW)	$ 1,636	$ 1,629	$ 1,622	$ 1,615	$ 1,633	$ 1,652	$ 1,671	$ 1,690	$ 1,709	$ 1,727	$ 1,746	$ 1,765	$ 1,784	$ 1,803	$ 1,822	$ 1,841	$ 1,860	$ 1,878	$ 1,897
4	Wind Capacity Factor (%)	29.9%	30.1%	30.3%	30.5%	30.5%	30.6%	30.6%	30.6%	30.6%	30.7%	30.7%	30.7%	30.7%	30.8%	30.8%	30.8%	30.8%	30.9%	30.9%

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

PATRICK D. KAUFFMAN

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF PATRICK D. KAUFFMAN

Line No.

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

A1. My name is Patrick Kauffman. My business address is: One Energy Plaza, Detroit, MI 48226. I am employed by DTE Energy Corporate Services, LLC within the Controller's department as a Principal Supervisor – Renewable Energy Program.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric, DTE or Company).

Q3. What is your educational background?

A3. In 1989, I received a Bachelor of Arts degree in Economics from The University of Notre Dame. In 1991, I received a Master of Business Administration degree in Finance from Michigan State University.

Q4. What work experience do you have?

A4. I started my employment with Detroit Edison in November 1999, as Supervisor of Forecasting, Budgeting and Corporate Reporting in the Controller's Organization. I held several positions of increasing responsibilities within the Controller's Organization including Gross Margin Analysis, Detroit Edison Financial Planning and Analysis, Budgeting, Forecasting and Reporting and Corporate Support. In 2008, I transferred to Regulatory Affairs and was a Case Manager for Gas Cost Recovery and Power Supply Cost Recovery cases. In 2010, I transferred back to the Controller's Organization and was responsible for benefits forecasting and reporting. In 2013, I obtained the position of Principal Financial Analyst responsible for forecasting and reporting for the Nuclear Generation organization.

Line No

In August 2016, I was appointed to my current position. I have sponsored testimony in the following cases:

U-15417-R	2008 Power Supply Cost Recovery Reconciliation
U-18242	Reconciliation of the DTE Electric 2016 REP Program
U-18232	2018 Amended REP
U-20172	Reconciliation of the DTE Electric 2017 REP Program
U-20484	Reconciliation of the DTE Electric 2018 REP Program
U-20723	Reconciliation of the DTE Electric 2019 REP Program
U-18232	2020 Amended REP Plan
U-20713	Voluntary Green Pricing (VGP) Plan
U-20851	August 2020 Amended REP
U-21010	Reconciliation of the DTE Electric 2020 REP Program
U-21198	Reconciliation of the DTE Electric 2021 REP Program
U-21285	2022 Amended REP Plan
U-21361	2023 Amended Renewable Energy Plan
U-21353	Reconciliation of the DTE Electric 2022 REP Program
U-21550	Reconciliation of the DTE Electric 2023 REP Program

Q5. What are your current job responsibilities?

A5. My current position is Accounting Expert for the Renewable Energy group which includes the 2008 PA 295 and 2016 PA 342 Renewable Energy activities of the Company. My group is responsible for providing budgeting, forecasting, planning, regulatory case support, and reporting expenses and capitalized cost for the Renewable Energy group.

Line
No

Q6. What is the purpose of your testimony in this proceeding?

A6. The purpose of my testimony and supporting exhibits is to explain the Company's projected Renewable Energy capital, O&M and other expenses associated with implementing the Company's Commission-approved 2008 PA 295 and 2016 PA 342 Renewable Energy Plan (REP) and to outline key accounting practices related to DTE Electric's amended REP.

Q7. Are you sponsoring any exhibits?

A7. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-6	Expense Elements of Incremental Cost of Compliance
A-7	Rate Base Financial Data
A-8	Production Tax Credits
A-9	Return On Equity Calculation

Q8. Were these exhibits prepared by you or under your direction?

A8. Yes, they were.

Capital, O&M, Other Expenses, and PTCs

Q9. Can you describe the line items shown on Exhibit A-6, Expense Elements of Incremental Cost of Compliance?

A9. Yes. I describe the line items below.

Line No

Line 1 - Total Royalty and Easement Payments are the ongoing contractual payments to land grantors in areas where wind and solar parks have been completed.

Line 2 - Administrative Expense is the ongoing incremental program administrative expenses associated with the Renewable Energy Plan primarily related to commercial and regulatory activities related to administering the Plan.

Line 3 - O&M Expense (MPSC Accounts 920, 921, 923, and 553) are the ongoing incremental program administrative expenses associated with the Renewable Energy Plan and related expenses associated with the cost of maintaining solar and wind assets. Included in this total are the MIREC fees paid for tracking of the Renewable Energy Credits (REC) in the database.

Line 4 - Insurance Expense is the calculated payments for protection of property for wind and solar programs. The REP assumes that annual insurance costs represent approximately 0.075% of the capital equipment costs which is consistent with the Company's experience related to other utility capital investment.

Line 5 - Property Tax Expense is discussed in Company Witness Ms. Wisniewski's testimony.

Line 6 - Miscellaneous Other Power is the Coke Oven Gas Expense recorded related to the purchase of Coke Oven Gas used to create Advanced Cleaner Energy Credits (ACECs). The Company stopped purchasing Coke oven gas in 2013.

Line No

Line 7 - Book Depreciation represents the depreciation recorded on the Company's books associated with Plant in Service assets for the Renewable Energy Plan based on balances as of the commercial operation date of these assets.

Line 8 - Interest Received from ITC Holdings Corp represents interest received on sums advanced to ITC for construction of interconnection facilities and/or network upgrades to the transmission system owned by ITC (which sums will be reimbursed to DTE Electric upon its generation facilities being interconnected to the ITC facilities). The interest received is credited to the incremental cost of compliance to offset the working capital costs associated with carrying a balance receivable from ITC.

Line 9 – Represents the equity portion of AFUDC on an after tax basis.

Line 10 – Represents the debt portion of AFUDC on an after tax basis.

Line 11 – Represents the gross up for taxes for AFUDC Equity.

Line 12 – Represents the amortization of the AFUDC Equity Tax Regulatory Asset.

Q10. What depreciation rates were used to calculate the expense shown on line 7 of Exhibit A-6?

A10. The September 26, 2014 order in Case No. U-16991 revised depreciation rates for the wind and solar REP plant, effective upon issuance of a final Commission order in the next REP Plan case. The next case (U-17793) was filed June 2, 2015. The

U-17793 plan was approved by a Commission order dated November 5, 2015. In that order the Commission made the U-16991 depreciation rates effective December 1, 2015. As a result, the Company was using the interim rates of 4.24% for wind and 5.26% for solar until December 1, 2015. Starting in December of 2015 the revised rates of 3.71% for wind and 4.93% for solar are applied.

Q11. What comprises the Plant in Service shown on Exhibit A-7?

A11. Plant in Service, shown on lines 1 through 5 of Exhibit A-7, is comprised of the cost of completed solar and wind projects that have been placed in service per the REP overview discussed in the direct testimony of Company Witness Mr. Bilyeu.

Q12. What does Depreciation Reserve represent in the Rate Base Financial Data in Exhibit A-7?

A12. Depreciation Reserve, shown on lines 7 through 10 of Exhibit A-7, is the accumulated book depreciation associated with the depreciation of the Company's PA 295, PA 342, and PA 235 Renewable Energy program plant in service.

Q13. What does Construction Work In Progress represent in the Rate Base Financial Data in Exhibit A-7?

A13. Construction Work in Progress (CWIP), shown on lines 12 through 17 of Exhibit A-6, represents the costs related to erecting wind and solar assets. As they are completed, project costs are moved from CWIP to plant in service.

Q14. What is the Renewable Energy Credit (REC) Inventory shown in the Rate Base Financial Data in Exhibit A-7?

Line
No

A14. The REC Inventory Balance, shown on lines 19 through 22 of Exhibit A-6, contains the dollar value of renewable energy credits that are part of the Company's PA 295 as amended by PA 342 and PA 235 Renewable Energy program as further explained in the testimony of Witness Bilyeu.

Q15. What is the ITC Holdings Corp. A/R shown in the Rate Base Financial Data in Exhibit A-7?

A15. This represents an upfront payment made to ITC in order to start certain construction and procurement of long lead-time items related to the interconnection of a wind generating facility. Reimbursement of this upfront payment is due back to DTE Electric following the start of commercial operation of the generating facility.

Q16. What is the Big Turtle Interconnect, LLC - Equity in Earnings shown in the Rate Base Financial Data in Exhibit A-7?

A16. This represents the program's share of the assets related to the shared facility, Big Turtle Interconnect, LLC.

Q17. How did you develop the Production Tax Credit (PTC) amount on Exhibit A-8, line 15?

A17. The line items shown on Attachment 3, Production Tax Credits (PTC) include the following: The production tax credits are calculated by multiplying the eligible in-service megawatt hours by the tax credit rate to get the production tax credit amounts. On August 16, 2022, the Inflation Reduction Act (IRA) was signed into law. The IRA introduces a change in the way PTC is calculated for assets placed in

service after December 31, 2021. The 2023 rate is 2.8 cents per kWh for projects placed in service before January 1, 2022. For projects placed in service after December 31, 2021, the rate is 2.75 cents per kWh.

PTCs for projects placed in service before January 1, 2022 are included on lines 1-5. PTCs for qualified projects placed in service after December 31, 2021 are included on lines 6-10.

The production tax credit assumes 2% inflation factor in 2024 through 2045. The IRS updates the PTC rate annually and we adjust accordingly, which has historically approximated a 2% annual increase. The adjustment for actual inflation occurs when the IRS publishes new inflation factors. The calculated tax credit amount is then grossed up for taxes. Since tax credits are post tax adjustments, in order to include them in the pre-tax incremental cost of compliance, they must be grossed up (increased) for taxes. This grossed up amount (line 20) reduces the incremental cost of compliance. The tax credits reduce the REP cost of compliance effective upon the in-service date of the eligible assets. PTCs are assumed to be transferred (line 17) in the year they are generated at a 5% discount (line 18). The net amount of the discount is reflected on line 19 and the gross amount of the discount is reflected on line 20.

Q18. What is included in the line items shown on Exhibit A-9, Return on Equity (ROE) Calculation?

A18. Line 1 – This is the authorized 11.0% ROE for assets required for compliance for the 2008 PA 295 as amended by 2016 PA 342 Renewable Energy program.

Line No

Line 2 – In the order dated July 18, 2019 in Case No. U-18232, the Commission noted that the company shall use the Commission-approved ROE, rather than the REP-approved ROE for any portions of the Fairbanks, Isabella I, or Isabella II projects that are used to supply the MIGreenPower (Rider 17) instead of RPS needs. This is the 9.9% ROE for MIGreenPower (Rider 17) assets per the Commission order and all other future assets.

Line 3 – This is the weighted average ROE for REP compliance assets and MIGreenPower (Rider 17) assets and all other future assets. The weighted average ROE is calculated by weighting the REP compliance simplified rate base (Line 12) and the All Other simplified rate base (Line 21) with their respective ROEs. The weighted average ROE is utilized by Witness Vangilder in his Exhibit A-25 to calculate the Pre-Tax Rate of Return.

Lines 12 and 21 – These lines represent the compliance simplified rate base (Line 12) and the All Other simplified rate base (Line 21) which are calculated by subtracting the deferred federal taxes related to plant (Lines 11 and 20) from net plant (Lines 10 and 19).

Accounting Practices

Q19. Are the accounting practices outlined in this case consistent with the accounting practices approved by the Commission in Case No. U-18111?

A19. Yes. DTE Electric is currently using the accounting practices outlined in Case No. U-18111 for its approved, amended REP program.

Line
No

Q20. Is the Company accruing an Allowance for Funds Used During Construction (AFUDC) for the renewable assets under construction?

A20. Yes. The Company is accruing an Allowance for Funds Used During Construction (AFUDC) for the renewable assets under construction This is consistent with the approved accounting application in Case No. U-21496.

Q21. Does this complete your direct testimony?

A21. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

OF

PATRICK D. KAUFFMAN

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Expense Elements of Incremental Cost of Compliance

Case No.: U-21662
Exhibit: A-6
Witness: P. D. Kauffman
Page: 1 of 1

Line No.	(a)	(b)	(c) Prelim	(d) Prelim	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
		Units	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
1	Total Royalty and Easement Payments	$Mil	16.4	15.1	18.6	20.5	24.1	29.9	34.1	38.0	41.3	47.1	51.1	57.1	63.1	75.2	85.3	95.8	106.7	118.0	129.8	142.0	151.7	153.9	156.2	156.2
2	Administrative Expense	$Mil	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9
3	O&M-MPSC Accts. 553, 920, 921, 923	$Mil	33.8	27.6	47.4	51.8	59.2	71.1	81.0	90.4	96.5	105.1	110.5	119.1	127.6	142.9	154.3	165.7	177.1	188.6	200.0	211.4	221.1	221.2	221.3	221.3
4	Insurance Expense	$Mil	1.6	1.8	1.8	2.1	2.7	4.2	5.7	6.9	7.9	8.9	9.9	10.9	12.0	13.2	14.5	15.8	17.0	18.3	19.6	21.0	22.3	22.9	22.9	22.9
5	Property Tax	$Mil	21.6	24.5	25.7	33.9	47.1	65.7	83.0	65.0	73.9	82.7	91.2	100.5	110.7	121.4	132.4	143.5	154.8	166.2	177.6	188.3	196.2	199.4	200.2	200.4
6	Miscellaneous Other Power: Coke Oven Gas Expense	$Mil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Book Depreciation	$Mil	92.4	99.3	109.6	142.2	208.0	355.0	432.9	519.4	579.9	663.8	712.6	795.7	875.7	946.5	1,018.4	1,086.8	1,160.6	1,235.3	1,310.7	1,386.9	1,463.4	1,451.1	1,452.4	1,451.1
8	Interest Received from ITC Holdings Corp.	$Mil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	AFUDC Equity (After tax)	$Mil	0.0	(6.1)	(53.9)	(95.0)	(146.1)	(107.5)	(105.1)	(88.7)	(95.4)	(85.0)	(103.0)	(109.3)	(114.9)	(117.2)	(118.4)	(119.7)	(120.9)	(120.3)	(113.3)	(78.4)	(13.3)	0.0	0.0	0.0
10	AFUDC Debt (After tax)	$Mil	0.0	(2.4)	(23.2)	(40.9)	(62.8)	(46.3)	(45.2)	(38.2)	(41.1)	(36.6)	(44.3)	(47.0)	(49.4)	(50.4)	(50.9)	(51.5)	(52.0)	(51.8)	(48.7)	(33.7)	(5.7)	0.0	0.0	0.0
11	AFUDC Equity Tax Gross Up	$Mil	0.0	(2.1)	(18.8)	(33.1)	(50.9)	(37.5)	(36.6)	(30.9)	(33.3)	(29.6)	(35.9)	(38.1)	(40.1)	(40.8)	(41.3)	(41.7)	(42.1)	(41.9)	(39.5)	(27.3)	(4.6)	0.0	0.0	0.0
12	AFUDC Equity Tax Regulatory Asset Amortization	$Mil	0.0	-	0.1	0.6	1.8	3.8	6.0	7.7	9.4	10.9	12.4	14.0	15.8	17.7	19.6	21.6	23.6	25.6	27.6	29.6	31.2	32.0	32.1	32.1

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Rate Base Financial Data
($ Millions)

Case No.: U-21662
Exhibit: A-7
Witness: P. D. Kauffman
Page: 1 of 1

Line No.	(a) Description	(b) Prelim 2022	(c) Prelim 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040	(u) 2041	(v) 2042	(w) 2043	(x) 2044	(y) 2045
1	**Plant in Service**																								
2	Beginning Balance	2,458.3	2,457.8	2,833.8	2,866.7	3,552.4	4,931.8	8,001.2	9,690.6	11,557.7	12,884.7	14,735.7	15,855.2	17,696.1	19,463.3	21,389.1	23,336.3	25,305.1	27,295.4	29,307.2	31,340.6	33,395.4	35,310.0	35,347.5	35,385.7
3	In Service Amounts	23.6	369.9	32.9	685.7	1,379.4	3,069.4	1,689.4	1,867.1	1,327.1	1,851.0	1,119.6	1,840.8	1,767.3	1,925.7	1,947.2	1,968.8	1,990.3	2,011.8	2,033.4	2,054.9	1,914.6	37.5	38.2	39.2
4	Ending Balance	2,457.8	2,833.8	2,866.7	3,552.4	4,931.8	8,001.2	9,690.6	11,557.7	12,884.7	14,735.7	15,855.2	17,696.1	19,463.3	21,389.1	23,336.3	25,305.1	27,295.4	29,307.2	31,340.6	33,395.4	35,310.0	35,347.5	35,385.7	35,424.9
5	Average Balance	2,470.1	2,781.5	2,850.3	3,209.5	4,242.1	6,466.5	8,845.9	10,624.1	12,221.2	13,810.2	15,295.5	16,775.7	18,579.7	20,426.2	22,362.7	24,320.7	26,300.2	28,301.3	30,323.9	32,368.0	34,352.7	35,328.8	35,366.6	35,405.3
6																									
7	**Depreciation Reserve**																								
8	Beginning Balance	388.3	468.7	568.0	677.6	819.8	1,027.8	1,382.7	1,815.6	2,335.0	2,914.9	3,578.7	4,291.3	5,087.0	5,962.8	6,909.3	7,927.7	9,014.5	10,175.1	11,410.4	12,721.1	14,108.0	15,571.4	17,022.6	18,475.0
9	Ending Balance	468.7	568.0	677.6	819.8	1,027.8	1,382.7	1,815.6	2,335.0	2,914.9	3,578.7	4,291.3	5,087.0	5,962.8	6,909.3	7,927.7	9,014.5	10,175.1	11,410.4	12,721.1	14,108.0	15,571.4	17,022.6	18,475.0	19,926.2
10	Average Balance	428.5	528.9	622.8	748.7	923.8	1,205.3	1,599.2	2,075.3	2,625.0	3,246.8	3,935.0	4,689.2	5,524.9	6,436.0	7,418.5	8,471.1	9,594.8	10,792.8	12,065.8	13,414.6	14,839.7	16,297.0	17,748.8	19,200.6
11																									
12	**Construction Work in Progress**																								
13	Beginning Balance	365.8	494.5	705.9	1,824.6	3,323.3	4,135.8	2,855.6	2,722.1	2,485.2	2,594.1	2,328.4	2,949.2	2,974.7	3,135.1	3,169.4	3,203.8	3,238.2	3,267.7	3,228.9	2,975.7	1,719.3	0.0	0.0	0.0
14	Transfer to Plant In Service	(23.6)	(369.9)	(32.9)	(685.7)	(1,379.4)	(3,069.4)	(1,689.4)	(1,867.1)	(1,327.1)	(1,851.0)	(1,119.6)	(1,840.8)	(1,767.3)	(1,925.7)	(1,947.2)	(1,968.8)	(1,990.3)	(2,011.8)	(2,033.4)	(2,054.9)	(1,914.6)	(37.5)	(38.2)	(39.2)
15	Plus: Additions	151.9	581.3	1,151.6	2,184.4	2,191.9	1,789.2	1,555.8	1,630.2	1,435.9	1,585.3	1,740.4	1,866.4	1,927.6	1,960.1	1,981.6	2,003.1	2,019.8	1,973.1	1,780.1	798.5	195.3	37.5	38.2	39.2
16	Ending Balance	494.5	705.9	1,824.6	3,323.3	4,135.8	2,855.6	2,722.1	2,485.2	2,594.1	2,328.4	2,949.2	2,974.7	3,135.1	3,169.4	3,203.8	3,238.2	3,267.7	3,228.9	2,975.7	1,719.3	0.0	0.0	0.0	0.0
17	Average Balance	430.0	450.8	1,265.2	2,573.9	3,729.5	3,495.7	2,788.8	2,603.6	2,539.6	2,461.2	2,638.8	2,962.0	3,054.9	3,152.3	3,186.6	3,221.0	3,252.9	3,248.3	3,102.3	2,347.5	859.7	0.0	0.0	0.0
18																									
19	**REC/ACEC Inventory (1)**																								
20	Net RECs/ACECs Transferred to Inventory	(0.5)	0.0	(1.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Ending Balance	1.4	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Average Balance	1.7	1.4	0.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																									
24	**ITC Holdings Corp. A/R**																								
25	Beginning Balance	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	1.0	3.0	6.0	10.0	15.0	21.0	28.0	36.0	45.0	55.0	66.0	78.0	91.0	105.0	120.0
26	Additions	-	-	-	-	-	-	-	-	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	11.0	12.0	13.0	14.0	15.0	16.0
27	Ending Balance	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	1.0	3.0	6.0	10.0	15.0	21.0	28.0	36.0	45.0	55.0	66.0	78.0	91.0	105.0	120.0	136.0
28	Average Balance	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.5	2.0	4.5	8.0	12.5	18.0	24.5	32.0	40.5	50.0	60.5	72.0	84.5	98.0	112.5	128.0
29																									
30	**Big Turtle Interconnect, LLC - Equity in Earnings**																								
31	Beginning Balance	(0.0)	(0.0)	1.7	1.5	1.4	1.3	1.2	1.0	0.9	0.8	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Additions	-	-	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)									
33	Ending Balance	(0.0)	1.7	1.5	1.4	1.3	1.2	1.0	0.9	0.8	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Average Balance	(0.0)	0.8	1.6	1.5	1.3	1.2	1.1	1.0	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Large Customer Voluntary Green Program

Line No.	Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
35	**Plant in Service**																								
36	Beginning Balance	722.2	729.3	773.1	773.1	1,424.2	2,769.1	5,804.8	7,467.2	9,306.6	10,605.2	12,427.1	13,516.9	15,327.2	17,063.2	18,957.1	20,871.7	22,807.2	24,763.5	26,740.6	28,738.6	30,757.4	32,635.2	32,635.2	32,635.2
37	In Service Amounts	7.1	43.8	-	651.1	1,344.9	3,035.7	1,662.4	1,839.4	1,298.7	1,821.9	1,089.8	1,810.3	1,736.1	1,893.8	1,914.6	1,935.5	1,956.3	1,977.1	1,998.0	2,018.8	1,877.8	-	-	-
38	Ending Balance	729.3	773.1	773.1	1,424.2	2,769.1	5,804.8	7,467.2	9,306.6	10,605.2	12,427.1	13,516.9	15,327.2	17,063.2	18,957.1	20,871.7	22,807.2	24,763.5	26,740.6	28,738.6	30,757.4	32,635.2	32,635.2	32,635.2	32,635.2
39	Average Balance	725.8	751.2	773.1	1,098.6	2,096.6	4,287.0	6,636.0	8,386.9	9,955.9	11,516.2	12,972.0	14,422.0	16,195.2	18,010.2	19,914.4	21,839.5	23,785.3	25,752.0	27,739.6	29,748.0	31,696.3	32,635.2	32,635.2	32,635.2
40																									
41	**Depreciation Reserve**																								
42	Beginning Balance	13.0	39.5	67.1	95.8	155.7	280.2	550.4	897.6	1,330.2	1,822.3	2,397.8	3,021.6	3,727.6	4,512.8	5,368.3	6,294.8	7,293.1	8,364.0	9,508.2	10,726.6	11,993.1	13,338.2	14,681.8	16,025.3
43	Ending Balance	39.5	67.1	95.8	155.7	280.2	550.4	897.6	1,330.2	1,822.3	2,397.8	3,021.6	3,727.6	4,512.8	5,368.3	6,294.8	7,293.1	8,364.0	9,508.2	10,726.6	11,993.1	13,338.2	14,681.8	16,025.3	17,368.9
44	Average Balance	26.3	53.3	81.4	125.7	218.0	415.3	724.0	1,113.9	1,576.2	2,110.0	2,709.7	3,374.6	4,120.2	4,940.6	5,831.5	6,794.0	7,828.6	8,936.1	10,117.4	11,359.8	12,665.7	14,010.0	15,353.6	16,697.1
45																									
46	**Construction Work in Progress**																								
47	Beginning Balance	46.6	185.1	705.9	1,824.6	3,323.3	4,135.8	2,855.6	2,722.1	2,485.2	2,594.1	2,328.4	2,949.2	2,974.7	3,135.1	3,169.4	3,203.8	3,238.2	3,267.7	3,228.9	2,975.7	1,719.3	0.0	0.0	0.0
48	Transfer to Plant In Service	(7.1)	(43.8)	-	(651.1)	(1,344.9)	(3,035.7)	(1,662.4)	(1,839.4)	(1,298.7)	(1,821.9)	(1,089.8)	(1,810.3)	(1,736.1)	(1,893.8)	(1,914.6)	(1,935.5)	(1,956.3)	(1,977.1)	(1,998.0)	(2,018.8)	(1,877.8)	-	-	-
49	Plus: Additions	145.6	564.6	1,118.7	2,149.8	2,157.4	1,755.5	1,528.8	1,602.5	1,407.5	1,556.2	1,710.6	1,835.9	1,896.4	1,928.2	1,949.0	1,969.8	1,985.8	1,938.4	1,744.7	762.4	158.5	-	-	-
50	Ending Balance	185.1	705.9	1,824.6	3,323.3	4,135.8	2,855.6	2,722.1	2,485.2	2,594.1	2,328.4	2,949.2	2,974.7	3,135.1	3,169.4	3,203.8	3,238.2	3,267.7	3,228.9	2,975.7	1,719.3	0.0	0.0	0.0	0.0
51	Average Balance	115.8	445.5	1,265.2	2,573.9	3,729.5	3,495.7	2,788.8	2,603.6	2,539.6	2,461.2	2,638.8	2,962.0	3,054.9	3,152.3	3,186.6	3,221.0	3,252.9	3,248.3	3,102.3	2,347.5	859.7	0.0	0.0	0.0

Compliance

Line No.	Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
52	**Plant in Service**																								
53	Beginning Balance	1,736.1	1,728.5	2,060.7	2,093.6	2,128.2	2,162.7	2,196.4	2,223.4	2,251.1	2,279.5	2,308.6	2,338.4	2,368.9	2,400.1	2,432.0	2,464.6	2,497.9	2,531.9	2,566.6	2,602.0	2,638.1	2,674.9	2,712.4	2,750.6
54	In Service Amounts	16.4	326.1	32.9	34.6	34.5	33.7	27.0	27.7	28.4	29.1	29.8	30.5	31.2	31.9	32.6	33.3	34.0	34.7	35.4	36.1	36.8	37.5	38.2	39.2
55	Ending Balance	1,728.5	2,060.7	2,093.6	2,128.2	2,162.7	2,196.4	2,223.4	2,251.1	2,279.5	2,308.6	2,338.4	2,368.9	2,400.1	2,432.0	2,464.6	2,497.9	2,531.9	2,566.6	2,602.0	2,638.1	2,674.9	2,712.4	2,750.6	2,789.8
56	Average Balance	1,744.4	2,030.3	2,077.2	2,110.9	2,145.4	2,179.5	2,209.9	2,237.2	2,265.3	2,294.0	2,323.5	2,353.6	2,384.5	2,416.0	2,448.3	2,481.2	2,514.9	2,549.2	2,584.3	2,620.0	2,656.5	2,693.6	2,731.5	2,770.2
57																									
58	**Depreciation Reserve**																								
59	Beginning Balance	375.3	429.2	500.9	581.9	664.1	747.6	832.3	918.1	1,004.8	1,092.7	1,180.9	1,269.8	1,359.4	1,450.0	1,541.0	1,632.9	1,721.4	1,811.1	1,902.2	1,994.5	2,115.0	2,233.2	2,340.8	2,449.7
60	Ending Balance	429.2	500.9	581.9	664.1	747.6	832.3	918.1	1,004.8	1,092.7	1,180.9	1,269.8	1,359.4	1,450.0	1,541.0	1,632.9	1,721.4	1,811.1	1,902.2	1,994.5	2,115.0	2,233.2	2,340.8	2,449.7	2,557.3
61	Average Balance	402.3	475.6	541.4	623.0	705.8	789.9	875.2	961.5	1,048.8	1,136.8	1,225.3	1,314.6	1,404.7	1,495.5	1,586.9	1,677.2	1,766.3	1,856.7	1,948.4	2,054.7	2,174.1	2,287.0	2,395.2	2,503.5
62																									
63	**Construction Work in Progress**																								
64	Beginning Balance	319.2	309.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
65	Transfer to Plant In Service	(16.4)	(326.1)	(32.9)	(34.6)	(34.5)	(33.7)	(27.0)	(27.7)	(28.4)	(29.1)	(29.8)	(30.5)	(31.2)	(31.9)	(32.6)	(33.3)	(34.0)	(34.7)	(35.4)	(36.1)	(36.8)	(37.5)	(38.2)	(39.2)
66	Plus: Additions	6.3	16.7	32.9	34.6	34.5	33.7	27.0	27.7	28.4	29.1	29.8	30.5	31.2	31.9	32.6	33.3	34.0	34.7	35.4	36.1	36.8	37.5	38.2	39.2
67	Ending Balance	309.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0
68	Average Balance	314.1	5.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Production Tax Credits
($ Millions, except where noted)

Case No.: U-21662
Exhibit: A-8
Witness: P. D. Kauffman
Page: 1 of 1

Line No.	(a) Description	(b) Prelim 2022	(c) Prelim 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	® 2038	(s) 2039	(t) 2040	(u) 2041	(v) 2042	(w) 2043	(x) 2044	(y) 2045
1	**Production Tax Credits - Projects in service before Jan 1 2022**																								
2	Qualifying Generation (MWh)	2,880,154	2,440,007	2,248,454	2,179,547	2,134,995	1,914,765	1,920,011	1,599,514	1,240,948	496,029	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	PTC Rate ($/MWh)	26.00	28.00	29.00	29.00	30.00	30.00	31.00	31.00	31.00	32.00	32.00	33.00	33.00	34.00	34.00	35.00	35.00	36.00	37.00	37.00	38.00	38.00	39.00	40.00
4	Wind Production Tax Credits Net	74.9	68.3	65.2	63.2	64.0	57.4	59.5	49.6	38.5	15.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Reduction to Incremental Cost Of Compliance Grossed Up	101.1	92.2	88.0	85.3	86.4	77.5	80.3	66.9	51.9	21.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	**Production Tax Credits - Projects in service after Dec 31, 2021**																								
7	Qualifying Generation (MWh)	-	404,182	567,337	890,226	1,220,271	3,931,026	6,276,355	9,500,000	11,034,904	13,069,837	14,451,531	16,461,713	17,986,604	20,055,745	22,392,098	22,241,822	22,457,346	22,079,430	23,368,455	23,911,414	25,044,757	23,342,064	21,293,667	18,545,754
8	PTC Rate ($/MWh)		27.5	30.0	30.0	30.0	30.0	30.0	30.0	32.5	32.5	32.5	32.5	32.5	35.0	35.0	35.0	35.0	35.0	37.5	37.5	37.5	37.5	40.0	42.5
9	Production Tax Credits Net	-	11.1	17.0	26.7	36.6	117.9	188.3	285.0	358.6	424.8	469.7	535.0	584.6	702.0	783.7	778.5	786.0	772.8	876.3	896.7	939.2	875.3	851.7	788.2
10	Reduction to Incremental Cost Of Compliance Grossed Up	-	15.0	23.0	36.0	49.4	159.2	254.1	384.6	484.0	573.2	633.8	722.0	788.9	947.3	1,057.7	1,050.6	1,060.7	1,042.9	1,182.6	1,210.1	1,267.4	1,181.3	1,149.5	1,063.7
11	**Production Tax Credits - Total**																								
12	Qualifying Generation (MWh)	2,880,154	2,844,189	2,815,791	3,069,774	3,355,266	5,845,791	8,196,366	11,099,515	12,275,852	13,565,866	14,451,531	16,461,713	17,986,604	20,055,745	22,392,098	22,241,822	22,457,346	22,079,430	23,368,455	23,911,414	25,044,757	23,342,064	21,293,667	18,545,754
13	PTC Rate ($/MWh)		27.93	29.20	29.29	30.00	30.00	30.23	30.14	32.35	32.48	32.50	32.50	32.50	35.00	35.00	35.00	35.00	35.00	37.50	37.50	37.50	37.50	40.00	42.50
14	Total Production Tax Credits Net	74.9	79.4	82.2	89.9	100.7	175.4	247.8	334.6	397.1	440.6	469.7	535.0	584.6	702.0	783.7	778.5	786.0	772.8	876.3	896.7	939.2	875.3	851.7	788.2
15	Reduction to Incremental Cost Of Compliance Grossed Up	101.1	107.2	111.0	121.3	135.8	236.7	334.4	451.5	535.9	594.7	633.8	722.0	788.9	947.3	1,057.7	1,050.6	1,060.7	1,042.9	1,182.6	1,210.1	1,267.4	1,181.3	1,149.5	1,063.7
16	**Production Tax Credits - Transferability Assumptions**																								
17	Estimated Production Tax Credits to be Transferred		-	161.7	89.9	100.7	175.4	247.8	334.6	397.1	440.6	469.7	535.0	584.6	702.0	783.7	778.5	786.0	772.8	876.3	896.7	939.2	875.3	851.7	788.2
18	Estimated Discount Rate on Transfer		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
19	Estimated Discount Amount on Transfer of Credits		-	(8.1)	(4.5)	(5.0)	(8.8)	(12.4)	(16.7)	(19.9)	(22.0)	(23.5)	(26.8)	(29.2)	(35.1)	(39.2)	(38.9)	(39.3)	(38.6)	(43.8)	(44.8)	(47.0)	(43.8)	(42.6)	(39.4)
20	Adjustment to Incremental Cost Of Compliance Grossed Up		-	(10.9)	(6.1)	(6.8)	(11.8)	(16.7)	(22.6)	(26.8)	(29.7)	(31.7)	(36.1)	(39.4)	(47.4)	(52.9)	(52.5)	(53.0)	(52.1)	(59.1)	(60.5)	(63.4)	(59.1)	(57.5)	(53.2)

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Return on Equity Calculation
($ Millions, except where noted)

Case No.: U-21662
Exhibit: A-9
Witness: P.D. Kauffman
Page: 1 of 1

Line No.	(a) Description	(b) 2022 Prelim	(c) 2023 Prelim	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040	(u) 2041	(v) 2042	(w) 2043	(x) 2044	(y) 2045
1	REP Compliance Return	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
2	All Other Return	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%	9.90%
3	Weighted Average Return on Equity	10.61%	10.51%	10.35%	10.19%	10.09%	10.05%	10.03%	10.01%	10.00%	9.99%	9.98%	9.97%	9.96%	9.95%	9.95%	9.94%	9.94%	9.93%	9.93%	9.93%	9.93%	9.92%	9.92%	9.92%
4																									
5	Compliance																								
6	Plant in Service	1,744.4	2,030.3	2,077.2	2,110.9	2,145.4	2,179.5	2,209.9	2,237.2	2,265.3	2,294.0	2,323.5	2,353.6	2,384.5	2,416.0	2,448.3	2,481.2	2,514.9	2,549.2	2,584.3	2,620.0	2,656.5	2,693.6	2,731.5	2,770.2
7	CWIP	314.1	5.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0
8	Gross Plant	2,058.5	2,035.6	2,077.2	2,110.9	2,145.4	2,179.5	2,209.9	2,237.2	2,265.3	2,294.0	2,323.5	2,353.6	2,384.5	2,416.0	2,448.3	2,481.2	2,514.9	2,549.2	2,584.3	2,620.0	2,656.5	2,693.6	2,731.5	2,770.2
9	Accumulated Depreciation	(402.3)	(475.6)	(541.4)	(623.0)	(705.8)	(789.9)	(875.2)	(961.5)	(1,048.8)	(1,136.8)	(1,225.3)	(1,314.6)	(1,404.7)	(1,495.5)	(1,586.9)	(1,677.2)	(1,766.3)	(1,856.7)	(1,948.4)	(2,054.7)	(2,174.1)	(2,287.0)	(2,395.2)	(2,503.5)
10	Net Plant	1,656.2	1,560.0	1,535.8	1,487.9	1,439.6	1,389.6	1,334.7	1,275.8	1,216.5	1,157.2	1,098.1	1,039.0	979.8	920.6	861.3	804.1	748.6	692.6	635.9	565.3	482.4	406.6	336.2	266.7
11	Deferred Federal Tax	(271.0)	(275.3)	(285.4)	(296.4)	(296.2)	(292.2)	(286.1)	(275.8)	(263.1)	(250.0)	(236.7)	(223.1)	(209.3)	(195.1)	(180.8)	(166.9)	(153.5)	(139.8)	(125.5)	(107.4)	(86.0)	(66.3)	(47.7)	(28.3)
12	Simplified Rate Base	1,385.2	1,284.7	1,250.4	1,191.5	1,143.4	1,097.4	1,048.6	1,000.0	953.5	907.2	861.4	815.9	770.5	725.5	680.6	637.1	595.1	552.8	510.4	457.9	396.4	340.4	288.5	238.4
13																									
14	All Other																								
15	Plant in Service	725.8	751.2	773.1	1,098.6	2,096.6	4,287.0	6,636.0	8,386.9	9,955.9	11,516.2	12,972.0	14,422.0	16,195.2	18,010.2	19,914.4	21,839.5	23,785.3	25,752.0	27,739.6	29,748.0	31,696.3	32,635.2	32,635.2	32,635.2
16	CWIP	115.8	445.5	1,265.2	2,573.9	3,729.5	3,495.7	2,788.8	2,603.6	2,539.6	2,461.2	2,638.8	2,962.0	3,054.9	3,152.3	3,186.6	3,221.0	3,252.9	3,248.3	3,102.3	2,347.5	859.7	0.0	0.0	0.0
17	Gross Plant	841.6	1,196.7	2,038.3	3,672.6	5,826.2	7,782.7	9,424.8	10,990.5	12,495.5	13,977.4	15,610.8	17,384.0	19,250.1	21,162.4	23,101.0	25,060.4	27,038.3	29,000.4	30,841.9	32,095.5	32,555.9	32,635.2	32,635.2	32,635.2
18	Accumulated Depreciation	(26.3)	(53.3)	(81.4)	(125.7)	(218.0)	(415.3)	(724.0)	(1,113.9)	(1,576.2)	(2,110.0)	(2,709.7)	(3,374.6)	(4,120.2)	(4,940.6)	(5,831.5)	(6,794.0)	(7,828.6)	(8,936.1)	(10,117.4)	(11,359.8)	(12,665.7)	(14,010.0)	(15,353.6)	(16,697.1)
19	Net Plant	815.4	1,143.4	1,956.9	3,546.8	5,608.2	7,367.3	8,700.9	9,876.7	10,919.3	11,867.4	12,901.1	14,009.4	15,129.9	16,221.9	17,269.5	18,266.5	19,209.7	20,064.2	20,724.5	20,735.6	19,890.3	18,625.2	17,281.6	15,938.1
20	Deferred Federal Tax	(52.7)	(96.1)	(130.4)	(178.7)	(277.0)	(447.5)	(698.9)	(986.4)	(1,266.6)	(1,536.8)	(1,786.4)	(1,999.2)	(2,191.5)	(2,386.5)	(2,583.6)	(2,780.6)	(2,977.2)	(3,168.3)	(3,349.0)	(3,517.3)	(3,662.3)	(3,746.1)	(3,717.5)	(3,579.8)
21	Simplified Rate Base	762.7	1,047.3	1,826.5	3,368.1	5,331.3	6,919.8	8,001.9	8,890.3	9,652.7	10,330.5	11,114.7	12,010.2	12,938.4	13,835.4	14,685.9	15,485.9	16,232.5	16,895.9	17,375.5	17,218.4	16,228.0	14,879.0	13,564.1	12,358.3
22																									

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

FRANK M. KOPINSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF FRANK M. KOPINSKI

Line No.

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

A1. My name is Frank M. Kopinski. My business address is 8001 Haggerty Road Belleville, MI 48111. 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. I am currently a Principal Engineer in the Power Supply Systems & Modeling team within the Generation Optimization department.

Q4. What is your educational background?

A4. I received a Bachelor of Science Degree in Chemical Engineering from Michigan Technological University in 2012.

Q5. What is your work experience?

A5. In 2012, I was hired by DTE Energy as an Associate Engineer as part of the Engineering Support Organization – Chemical Engineering Group, stationed at Monroe Power Plant. In that role, I supported the safe and economical operation of the power plant by managing the boiler water treatment equipment and supporting systems. In 2019, I transitioned to the Generation Optimization department and have held various responsibilities in the Power Supply Strategy & Modeling team.

Q6. What are your duties and responsibilities in your current position?

A6. My current responsibilities include overseeing and implementing the Company's strategies for Financial Transmission Rights to recoup congestion charges from Mid-continent Independent System Operator (MISO). I also manage the offer strategies for the Company's Renewable Energy Units into the MISO Market to ensure they accurately reflect the operating conditions for each unit. I also coordinate environmental strategies to ensure environmental compliance while minimizing the impacts to the customer.

Q7. Have you previously sponsored testimony before the Michigan Public Service Commission?

A7. Yes. I sponsored testimony in the following MPSC case:

U-21010	DTE Electric's 2020 Renewable Energy Plan Reconciliation
U-21198	DTE Electric's 2021 Renewable Energy Plan Reconciliation
U-21353	DTE Electric's 2022 Renewable Energy Plan Reconciliation
U-21550	DTE Electric's 2023 Renewable Energy Plan Reconciliation
U-21285	DTE Electric's 2022 Amended Renewable Energy Plan
U-21361	DTE Electric's 2023 Amended Renewable Energy Plan

Line No

Purpose of Testimony

Q8. What is the purpose of your testimony?

A8. The purpose of my testimony is to:

1) Present the Company's approved transfer price schedules for the Company's 2008 Public Act (PA) 295, as amended by 2016 PA 342, renewable energy contracts and Company-owned renewable energy system that run through 2029.

2) Obtain approval of the Company's transfer price schedules that extend previous transfer price schedules through 2045 in accord with 2023 PA 235 (PA 235).

3) Present the projected renewable energy generation expense for the Company for years 2022 through 2045 which will be transferred for recovery through the Company's PSCR mechanism, for renewable energy contracts and Company-owned renewable energy systems that will be used to comply with PA 235.

Q9. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-10		U-15806 Transfer Prices
A-11		2012 MPSC Staff Transfer Prices
A-12		2014 MPSC Staff Transfer Prices
A-13		2015 MPSC Staff Transfer Prices
A-14		2016 MPSC Staff Transfer Prices
A-15		2018 MPSC Staff Transfer Prices
A-16		2019 MPSC Staff Transfer Prices
A-17		2021 MPSC Staff Transfer Prices
A-18		2022 MPSC Staff Transfer Prices

Line No			
1	A-19		2023 MPSC Staff Transfer Prices
2	A-20	A1	2024 MPSC Staff Transfer Prices
3	A-20	A2	2024 MPSC Staff Combined Cycle Levelized Cost
4	A-20	A3	2024 MPSC Staff Combined Cycle Levelized Fuel Price
5	A-20.1		MPSC Staff Inflation Numbers
6	A-21		PSCR Transfer Expense

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

A10. Yes, they were.

Q11. What is the purpose of Exhibits A-10 through A-19?

A11. The purpose of Exhibits A-10 through A-19 are to present the Company's approved transfer price schedules that are being used by one or more of the Company's 2008 PA 295 renewable energy contracts and Company-owned renewable energy systems. Projects are assigned to use the most recently approved transfer price schedule for the life of that project, at the time of the Michigan Public Service Commission's (MPSC or Commission) project approval. Table 1 is an outline of those transfer price schedules and the applicable Renewable Energy Plan (REP) Reconciliation Case where the transfer price schedule was approved. Table 2 shows an outline of the Company's approved renewable energy contracts and Company-owned renewable energy systems and their assigned transfer price schedule. For purposes of this filing the most recently approved transfer price schedule is the 2022 transfer price schedule and has been applied to all future projects, that have not been approved. The actual transfer price schedule assigned to each of those projects will

be the most recently approved transfer price schedule at the time of that project's MPSC approval.

Table 1 DTE Electric's Transfer Price Schedules

Exhibit	Transfer Price Schedule Name	Case Where Transfer Prices Proposed	Date Transfer Price Schedule Became Effective
A-10	U-15806	U-15806	10/21/2008
A-11	2012	U-16656	7/24/2012
A-12	2014	U-17632	7/23/2015
A-13	2015	U-17804	4/14/2016
A-14	2016	U-18082	2/28/2017
A-15	2018	U-20172	1/18/2019
A-16	2019	U-20484	2/6/2020
A-17	2021	U-21010	5/26/2022
A-18	2022	U-21198	4/24/2023 – Latest Approved
A-19	2023	U-21353	TBD

Line
No

Table 2 Breakdown of Approved Contract's and Company-owned Projects and Corresponding Transfer Prices Schedules

Transfer Price Schedule Name	Contracts approved to use Schedule	Company-owned projects approved to use Schedule
U-15806	• Heritage Stoney Corners Wind Farm I, LLC • L'Anse Warden Electric Company, LLC • WM Renewable Energy, LLC • Gratiot County Wind, LLC • Blue Water Renewables, Inc. • Tuscola Bay Wind, LLC	• Gratiot Wind Park • Thumb Wind Parks (Minden, McKinley, and Sigel Wind Parks) • DTE Electric Owned Solar (~13.75 MW)
2012	• Tuscola Wind II, LLC • Pheasant Run Wind, LLC • Big Turtle Wind Farm, LLC	• Echo Wind Park • Brookfield Wind Park • DTE Electric Owned Solar (~1.25 MW)
2014		• Pinnebog Wind Park • 2017 DTE Electric Owned Solar (50 MW)
2015		• Pine River Wind Park
2016		• Polaris Wind Park
2018		• Fairbanks Wind Park • Isabella Wind Park 1 • Isabella Wind Park 2
2019	• Assembly 3 • Riverfork	• Ford Rooftop Solar Pilot • Meridian Wind Park
2021		• Gratiot Solar • Pine River Solar • Polaris Solar • Sauk Solar • Big Turtle II
2022		• Fish Creek Solar Park • Little Trout Solar Park • Mission Road Solar Park • Coldwater River • White Pine Groove

Q12. How have Exhibits A-10 through A-19 changed since the Company's 2023 Amended REP Filing, Case U-21361?

A12. With the implementation of 2023 Public Act 235, the volumetric cost recovery mechanism was maintained although the twenty-year period was extended. To account for this, all previously approved transfer price schedules that did not have prices past 2029, now must include transfer prices out through 2045 for purposes of this filing. DTE Electric proposes the use of an inflation factor based on consumer price index (CPI) to consistently build transfer prices for the years 2030 through 2045, for all previously approved transfer price schedules. This methodology is consistent with the MPSC Staff's methodology outlined in their MPSC Transfer Price Schedule Update filed in Case No. U-15800 on April 23rd, 2024. See Exhibit 20.1 for the inflation factors applied by year and see the updated transfer price schedules shown in Exhibits A-10 through A-19.

Q13. What is the basis of the Company's proposed 2024 MPSC Staff Transfer Prices presented in Exhibit A-20 Schedule A1?

A13. The 2024 MPSC Staff Transfer Prices presented in Exhibit A-20 Schedule A1 were developed by the MPSC Staff and filed in Case No. U-15800 on April 18th, 2024. The MPSC Staff developed a projection of the total cost of a natural gas combined cycle gas turbine (CCGT) unit. The basis for these transfer prices is the levelized cost of energy (LCOE) of a CCGT for the base year 2028 shown on Exhibit A-20 Schedule A2, with a levelized natural gas price calculated from the U.S. Energy Information Administration's projection of natural gas prices at the Henry Hub shown on Exhibit A-20 Schedule A3. The 2024 MPSC Staff Transfer Prices were

presented in DTE Electric's 2023 Renewable Cost Reconciliation in Case No. U-21550 for Commission approval of those transfer prices for future projects.

Q14. What is your conclusion of the MPSC Staff's transfer price methodology?

A14. The Company has reviewed the MPSC Staff's transfer price methodology, including the levelized cost calculation variables, and finds it to be reasonable for the purpose of determining the transfer price schedule. The assumptions and calculations used by the MPSC Staff to develop the LCOE of a generic CCGT plant and the associated transfer price schedule are comparable to those used in previous renewable energy case proceedings that have been approved by the Commission.

Q15. How is the Company implementing transfer prices?

A15. The transfer price schedules are made up of a series of transfer prices for each year included in the schedule. The transfer price schedules that the Commission approves for each renewable energy contract and Company-owned renewable energy system is established as a floor for the lifecycle of the contract or project to ensure that the economic viability of projects that have been committed to will not be jeopardized by transfer price schedules that change in future years.

The Company will charge the Power Supply Cost Recovery (PSCR) for energy generated by an approved renewable energy contract or Company-owned renewable energy system at the PSCR Transfer Price. The PSCR Transfer Price for each renewable energy contract will be the lesser of the approved transfer price or renewable energy contract cost. The PSCR Transfer Price for renewable energy generated by Company-owned renewable energy systems will be either the

approved transfer price or the LCOE for each project, not to exceed the approved transfer price. This PSCR mechanism aligns with the order issued on July 9, 2020 in DTE Electric's Amended REP Plan Case No. 18232.

Q16. What is the purpose of Exhibit A-21?

A16. The purpose of Exhibit A-21 is to provide a projection of the renewable energy expense which will be recovered through the PSCR Transfer Price mechanism. Exhibit A-21 identifies each renewable energy contract and Company-owned renewable energy system with their associated transfer prices as well as the forecasted volume and expense of voluntary green pricing (VGP) programs. The forecasted volume and expense of VGP programs, referred to in Exhibit A-21 as MIGreenPower Subscribed Wind/Solar and VGP Subscribed Wind, are carved out of the total Generation and PSCR Transfer Expense as these expenses are borne by VGP customers rather than the Company's PSCR customers. Exhibit A-21 is subdivided to show which projects support the company's VGP programs and which projects support the compliance to the 2008 PA 295, 2016 PA 342, and 2023 PA 235.

The projected Company-owned generation volumes from Exhibit A-21 are used along with projected PPA volumes and each project's associated transfer prices to determine the projected PSCR expense in each year.

Q17. Does this complete your direct testimony?

A17. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

FRANK M. KOPINSKI

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
U-15806 Transfer Prices

Case No.: U-21662
Exhibit: A-10
Witness: F. M. Kopinski
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f) {(b) + (e)}	(g)	(h) {(b) + (g)}	(i)	(j) {(b) + (i)}	(k)	(l) {(b) + (k)}
					Landfill Gas/Biomass		Anaerobic/Cellulosic Digester		Solar		Wind	
Line No.	Year	Annual Average Locational Marginal Cost ($/MWh)	Final Capacity Cost ($/MW-yr.)	Final Capacity Cost @ 100% Capacity Factor ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)	Adjusted Capacity Payment ($/MWh)	Total Transfer Price ($/MWh)
1	2009	48.52	24,700	2.82	3.13	51.66	3.52	52.05	21.69	70.21	1.14	49.66
2	2010	54.39	30,000	3.42	3.81	58.20	4.28	58.67	26.34	80.73	1.38	55.77
3	2011	56.32	40,000	4.57	5.07	61.40	5.71	62.03	35.12	91.45	1.84	58.16
4	2012	71.73	60,000	6.83	7.59	79.32	8.54	80.27	52.54	124.27	2.75	74.49
5	2013	72.32	90,000	10.27	11.42	83.74	12.84	85.17	79.03	151.35	4.14	76.47
6	2014	73.05	125,000	14.27	15.85	88.90	17.84	90.88	109.76	182.81	5.75	78.80
7	2015	76.01	156,154	17.83	19.81	95.82	22.28	98.29	137.12	213.13	7.19	83.20
8	2016	78.06	162,831	18.54	20.60	98.65	23.17	101.23	142.59	220.65	7.47	85.53
9	2017	79.12	169,393	19.34	21.49	100.60	24.17	103.29	148.75	227.87	7.80	86.92
10	2018	81.20	176,047	20.10	22.33	103.53	25.12	106.32	154.59	235.79	8.10	89.30
11	2019	84.75	182,846	20.87	23.19	107.95	26.09	110.85	160.56	245.31	8.42	93.17
12	2020	88.04	189,960	21.63	24.03	112.07	27.03	115.07	166.35	254.39	8.72	96.76
13	2021	92.34	197,423	22.54	25.04	117.38	28.17	120.51	173.36	265.70	9.09	101.43
14	2022	96.36	205,164	23.42	26.02	122.38	29.28	125.63	180.16	276.51	9.44	105.80
15	2023	101.25	213,210	24.34	27.04	128.29	30.42	131.67	187.22	288.47	9.81	111.06
16	2024	106.78	221,470	25.21	28.01	134.80	31.52	138.30	193.95	300.73	10.17	116.95
17	2025	107.68	230,268	26.29	29.21	136.89	32.86	140.54	202.20	309.88	10.60	118.28
18	2026	111.74	239,304	27.32	30.35	142.09	34.15	145.89	210.14	321.88	11.02	122.76
19	2027	116.34	248,730	28.39	31.55	147.89	35.49	151.83	218.41	334.75	11.45	127.79
20	2028	124.68	258,620	29.44	32.71	157.39	36.80	161.48	226.48	351.16	11.87	136.55
21	2029	129.94	268,341	30.63	34.04	163.98	38.29	168.23	235.64	365.58	12.35	142.29

22	Technology	Capacity Factor %	On-Peak Capacity Credit %
23	Landfill Gas/Biomass	90%	100.0%
24	Anaerobic/Cellulosic Digester	80%	100.0%
25	Solar	13%	100.0%
26	Wind	31%	12.5%

27															
28													Year	Inflation	Inflation %
29	2030		274,028	31.28	34.76	167.45	39.10	171.80	240.63	373.32	12.61	145.31	2030	2.1	0.021191
30	2031		279,897	31.95	35.50	171.04	39.94	175.48	245.78	381.32	12.88	148.42	2031	2.1	0.02142
31	2032		285,944	32.64	36.27	174.73	40.80	179.27	251.09	389.56	13.16	151.63	2032	2.2	0.021602
32	2033		292,111	33.35	37.05	178.50	41.68	183.13	256.51	397.96	13.45	154.90	2033	2.2	0.021569
33	2034		298,401	34.06	37.85	182.34	42.58	187.08	262.03	406.53	13.74	158.23	2034	2.2	0.021531
34	2035		304,837	34.80	38.67	186.28	43.50	191.11	267.68	415.29	14.03	161.64	2035	2.2	0.021568
35	2036		311,408	35.55	39.50	190.29	44.44	195.23	273.45	424.25	14.33	165.13	2036	2.2	0.021556
36	2037		318,119	36.31	40.35	194.39	45.39	199.44	279.35	433.39	14.64	168.69	2037	2.2	0.021552
37	2038		324,977	37.10	41.22	198.58	46.37	203.74	285.37	442.73	14.96	172.32	2038	2.2	0.021557
38	2039		331,982	37.90	42.11	202.87	47.37	208.13	291.52	452.28	15.28	176.04	2039	2.2	0.021556
39	2040		339,138	38.71	43.02	207.24	48.39	212.61	297.80	462.02	15.61	179.83	2040	2.2	0.021554
40	2041		346,448	39.55	43.94	211.71	49.44	217.20	304.22	471.98	15.95	183.71	2041	2.2	0.021556
41	2042		353,916	40.40	44.89	216.27	50.50	221.88	310.78	482.16	16.29	187.67	2042	2.2	0.021555
42	2043		361,544	41.27	45.86	220.93	51.59	226.66	317.48	492.55	16.64	191.71	2043	2.2	0.021555
43	2044		369,337	42.16	46.85	225.69	52.70	231.55	324.32	503.17	17.00	195.85	2044	2.2	0.021555
44	2045		377,299	43.07	47.86	230.56	53.84	236.54	331.31	514.01	17.37	200.07	2045	2.2	0.021555

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2012 MPSC Staff Transfer Prices

Case No.: U-21662
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Line No.	(a) Year	(b) MPSC Staff 2012 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2012 Transfer Price - Variable Cost ($/MWh)	(d) 2012 MPSC Staff Transfer Price ($/MWh)
1	2013	29.13	35.49	64.62
2	2014	29.65	38.22	67.87
3	2015	30.16	40.99	71.16
4	2016	30.34	41.68	72.02
5	2017	30.31	40.89	71.20
6	2018	30.29	41.81	72.09
7	2019	30.29	43.17	73.46
8	2020	30.30	44.05	74.34
9	2021	30.49	45.25	75.75
10	2022	30.70	46.56	77.26
11	2023	30.88	47.93	78.81
12	2024	31.12	49.44	80.56
13	2025	31.35	50.96	82.31
14	2026	31.58	52.11	83.69
15	2027	31.78	52.77	84.56
16	2028	32.01	54.05	86.06
17	2029	32.21	55.45	87.66
18				
19	2030	32.89	56.63	89.52
20	2031	33.60	57.84	91.44
21	2032	34.32	59.09	93.41
22	2033	35.06	60.36	95.43
23	2034	35.82	61.66	97.48
24	2035	36.59	62.99	99.58
25	2036	37.38	64.35	101.73
26	2037	38.18	65.74	103.92
27	2038	39.01	67.15	106.16
28	2039	39.85	68.60	108.45
29	2040	40.71	70.08	110.79
30	2041	41.59	71.59	113.18
31	2042	42.48	73.13	115.61
32	2043	43.40	74.71	118.11
33	2044	44.33	76.32	120.65
34	2045	45.29	77.96	123.25

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2014 MPSC Staff Transfer Prices

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Line No.	(a) Year	(b) MPSC Staff 2014 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2014 Transfer Price - Variable Cost ($/MWh)	(d) 2014 MPSC Staff Transfer Price ($/MWh)
1	2014	31.19	38.93	70.12
2	2015	31.59	38.50	70.09
3	2016	32.03	38.37	70.40
4	2017	32.44	39.56	71.99
5	2018	32.74	41.16	73.89
6	2019	33.03	41.05	74.08
7	2020	33.37	40.64	74.01
8	2021	33.81	42.85	76.66
9	2022	34.30	44.19	78.49
10	2023	34.81	45.13	79.94
11	2024	35.29	45.62	80.91
12	2025	35.80	47.00	82.80
13	2026	36.33	49.00	85.33
14	2027	36.84	50.14	86.98
15	2028	37.33	51.36	88.69
16	2029	37.81	52.61	90.41
17				
18	2030	38.60	53.72	92.33
19	2031	39.43	54.88	94.30
20	2032	40.28	56.06	96.34
21	2033	41.15	57.27	98.42
22	2034	42.03	58.50	100.54
23	2035	42.94	59.77	102.71
24	2036	43.87	61.05	104.92
25	2037	44.81	62.37	107.18
26	2038	45.78	63.71	109.49
27	2039	46.76	65.09	111.85
28	2040	47.77	66.49	114.26
29	2041	48.80	67.92	116.73
30	2042	49.85	69.39	119.24
31	2043	50.93	70.88	121.81
32	2044	52.03	72.41	124.44
33	2045	53.15	73.97	127.12

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2015 MPSC Staff Transfer Prices

Case No.: U-21662
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Line No.	(a) Year	(b) MPSC Staff 2015 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2015 Transfer Price - Variable Cost ($/MWh)	(d) 2015 MPSC Staff Transfer Price ($/MWh)
1	2015	32.06	36.21	68.27
2	2016	32.61	36.79	69.40
3	2017	33.61	38.91	72.52
4	2018	34.52	40.55	75.07
5	2019	35.27	42.17	77.44
6	2020	36.04	43.33	79.37
7	2021	36.75	43.75	80.50
8	2022	37.33	44.31	81.64
9	2023	37.91	45.59	83.50
10	2024	38.43	46.28	84.72
11	2025	39.01	47.70	86.71
12	2026	39.56	48.72	88.28
13	2027	40.18	49.85	90.02
14	2028	40.81	51.87	92.68
15	2029	41.38	53.17	94.55
16				
17	2030	42.26	54.30	96.55
18	2031	43.16	55.46	98.62
19	2032	44.09	56.66	100.75
20	2033	45.05	57.88	102.93
21	2034	46.02	59.13	105.14
22	2035	47.01	60.40	107.41
23	2036	48.02	61.70	109.72
24	2037	49.06	63.03	112.09
25	2038	50.11	64.39	114.51
26	2039	51.19	65.78	116.97
27	2040	52.30	67.20	119.49
28	2041	53.42	68.65	122.07
29	2042	54.58	70.13	124.70
30	2043	55.75	71.64	127.39
31	2044	56.95	73.18	130.14
32	2045	58.18	74.76	132.94

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2016 MPSC Staff Transfer Prices

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Line No.	(a) Year	(b) MPSC Staff 2016 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2016 Transfer Price - Variable Cost ($/MWh)	(d) 2016 MPSC Staff Transfer Price ($/MWh)
1	2016	33.21	38.58	71.80
2	2017	34.01	40.61	74.62
3	2018	35.19	42.77	77.96
4	2019	36.15	44.49	80.64
5	2020	37.01	45.94	82.95
6	2021	37.77	47.97	85.75
7	2022	38.49	50.26	88.75
8	2023	39.07	50.87	89.94
9	2024	39.59	52.04	91.63
10	2025	40.07	53.41	93.48
11	2026	40.48	54.07	94.56
12	2027	40.92	55.63	96.55
13	2028	41.34	56.82	98.16
14	2029	41.77	58.11	99.88
15				
16	2030	42.66	59.34	102.00
17	2031	43.57	60.61	104.18
18	2032	44.51	61.92	106.43
19	2033	45.47	63.26	108.73
20	2034	46.45	64.62	111.07
21	2035	47.45	66.01	113.46
22	2036	48.47	67.44	115.91
23	2037	49.52	68.89	118.41
24	2038	50.59	70.37	120.96
25	2039	51.68	71.89	123.57
26	2040	52.79	73.44	126.23
27	2041	53.93	75.02	128.95
28	2042	55.09	76.64	131.73
29	2043	56.28	78.29	134.57
30	2044	57.49	79.98	137.47
31	2045	58.73	81.70	140.44

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2018 MPSC Staff Transfer Prices

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Line No.	(a) Year	(b) MPSC Staff 2018 Transfer Price - Fixed Cost	(c) MPSC Staff 2018 Transfer Price - Variable Cost ($/MWh)	(d) 2018 MPSC Staff Transfer Price ($/MWh)
1	2018	31.36	33.70	65.06
2	2019	31.81	34.35	66.16
3	2020	32.22	35.15	67.37
4	2021	32.57	36.62	69.19
5	2022	33.01	38.40	71.42
6	2023	33.51	40.04	73.54
7	2024	34.03	42.30	76.33
8	2025	34.45	43.55	78.00
9	2026	34.81	44.34	79.14
10	2027	35.17	45.52	80.69
11	2028	35.52	47.00	82.52
12	2029	35.90	48.59	84.49
13				
14	2030	36.66	49.62	86.28
15	2031	37.45	50.68	88.13
16	2032	38.25	51.78	90.03
17	2033	39.08	52.89	91.97
18	2034	39.92	54.03	93.96
19	2035	40.78	55.20	95.98
20	2036	41.66	56.39	98.05
21	2037	42.56	57.60	100.16
22	2038	43.48	58.85	102.32
23	2039	44.41	60.11	104.53
24	2040	45.37	61.41	106.78
25	2041	46.35	62.73	109.08
26	2042	47.35	64.09	111.43
27	2043	48.37	65.47	113.84
28	2044	49.41	66.88	116.29
29	2045	50.48	68.32	118.80

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DTE Electric Company
2024 Amended REP
2019 MPSC Staff Transfer Prices

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Line No.	(a) Year	(b) MPSC Staff 2019 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2019 Transfer Price - Variable Cost ($/MWh)	(d) 2019 MPSC Staff Transfer Price ($/MWh)
1	2019	31.99	30.25	62.23
2	2020	32.39	30.77	63.16
3	2021	32.71	31.87	64.58
4	2022	33.10	33.34	66.44
5	2023	33.62	35.20	68.82
6	2024	34.20	37.50	71.70
7	2025	34.73	38.78	73.52
8	2026	35.32	39.82	75.14
9	2027	35.94	41.37	77.31
10	2028	36.62	43.34	79.96
11	2029	37.35	46.17	83.52
12				
13	2030	38.14	47.15	85.29
14	2031	38.96	48.16	87.12
15	2032	39.80	49.20	89.00
16	2033	40.66	50.26	90.92
17	2034	41.53	51.34	92.88
18	2035	42.43	52.45	94.88
19	2036	43.34	53.58	96.92
20	2037	44.28	54.73	99.01
21	2038	45.23	55.91	101.15
22	2039	46.21	57.12	103.33
23	2040	47.20	58.35	105.55
24	2041	48.22	59.61	107.83
25	2042	49.26	60.89	110.15
26	2043	50.32	62.21	112.53
27	2044	51.41	63.55	114.95
28	2045	52.52	64.92	117.43

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2021 MPSC Staff Transfer Prices

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Line No.	Year	(a)	(b) MPSC Staff 2021 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2021 Transfer Price - Variable Cost ($/MWh)	(d) 2021 MPSC Staff Transfer Price ($/MWh)
1	2021		32.41	33.04	65.45
2	2022		33.02	33.22	66.24
3	2023		33.66	31.55	65.21
4	2024		34.36	32.92	67.28
5	2025		34.87	33.89	68.76
6	2026		35.27	35.01	70.29
7	2027		35.71	36.39	72.10
8	2028		36.17	37.99	74.15
9	2029		36.55	39.69	76.24
10					
11	2030		37.32	40.53	77.86
12	2031		38.12	41.40	79.52
13	2032		38.95	42.29	81.24
14	2033		39.79	43.21	83.00
15	2034		40.64	44.14	84.78
16	2035		41.52	45.09	86.61
17	2036		42.42	46.06	88.48
18	2037		43.33	47.05	90.38
19	2038		44.26	48.07	92.33
20	2039		45.22	49.10	94.32
21	2040		46.19	50.16	96.36
22	2041		47.19	51.24	98.43
23	2042		48.21	52.35	100.56
24	2043		49.24	53.48	102.72
25	2044		50.31	54.63	104.94
26	2045		51.39	55.81	107.20

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2022 MPSC Staff Transfer Prices

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Witness: F. M. Kopinski
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Line No.	Year	(a)	(b) MPSC Staff 2022 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2022 Transfer Price - Variable Cost ($/MWh)	(d) 2022 MPSC Staff Transfer Price ($/MWh)
1	2022		33.57	29.59	63.16
2	2023		33.87	29.10	62.97
3	2024		34.23	29.05	63.29
4	2025		34.83	29.76	64.59
5	2026		35.51	30.90	66.41
6	2027		36.13	31.87	68.00
7	2028		36.76	33.03	69.79
8	2029		37.41	34.42	71.82
9					
10	2030		38.20	35.15	73.35
11	2031		39.02	35.90	74.92
12	2032		39.86	36.68	76.53
13	2033		40.72	37.47	78.19
14	2034		41.60	38.28	79.87
15	2035		42.50	39.10	81.59
16	2036		43.41	39.94	83.35
17	2037		44.35	40.80	85.15
18	2038		45.31	41.68	86.98
19	2039		46.28	42.58	88.86
20	2040		47.28	43.50	90.77
21	2041		48.30	44.44	92.73
22	2042		49.34	45.40	94.73
23	2043		50.40	46.38	96.77
24	2044		51.49	47.37	98.86
25	2045		52.60	48.40	100.99

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2023 MPSC Staff Transfer Prices

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Line No.	(a) Year	(b) MPSC Staff 2023 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2023 Transfer Price - Variable Cost ($/MWh)	(d) 2023 MPSC Staff Transfer Price ($/MWh)
1	2023	36.74	25.89	62.64
2	2024	35.13	26.97	62.11
3	2025	35.07	27.43	62.50
4	2026	35.47	29.97	65.44
5	2027	36.17	31.95	68.12
6	2028	36.98	32.69	69.68
7	2029	37.82	33.00	70.83
8				
9	2030	38.62	33.70	72.33
10	2031	39.45	34.42	73.88
11	2032	40.30	35.16	75.47
12	2033	41.17	35.92	77.10
13	2034	42.06	36.70	78.76
14	2035	42.96	37.49	80.46
15	2036	43.89	38.30	82.20
16	2037	44.84	39.12	83.97
17	2038	45.80	39.96	85.78
18	2039	46.79	40.83	87.63
19	2040	47.80	41.71	89.51
20	2041	48.83	42.61	91.44
21	2042	49.88	43.52	93.42
22	2043	50.96	44.46	95.43
23	2044	52.05	45.42	97.49
24	2045	53.18	46.40	99.59

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2024 MPSC Staff Transfer Prices

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Witness: F. M. Kopinski
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Line No.	(a) Year	(b) MPSC Staff 2024 Transfer Price - Fixed Cost ($/MWh)	(c) MPSC Staff 2024 Transfer Price - Variable Cost ($/MWh)	(d) 2024 MPSC Staff Transfer Price ($/MWh)
1	2024	35.29	27.03	62.32
2	2025	35.31	30.29	65.60
3	2026	35.78	33.13	68.91
4	2027	36.33	34.08	70.40
5	2028	36.84	33.84	70.68
6	2029	37.40	34.06	71.47
7	2030	38.00	34.31	72.31
8	2031	38.64	35.04	73.69
9	2032	39.29	35.98	75.28
10	2033	39.93	36.93	76.86
11	2034	40.60	38.30	78.90
12	2035	41.23	39.30	80.53
13	2036	41.89	40.15	82.04
14	2037	42.63	41.09	83.72
15	2038	43.42	42.08	85.50
16	2039	44.20	43.02	87.22
17	2040	45.02	44.32	89.34
18	2041	45.86	45.57	91.43
19	2042	46.68	46.58	93.26
20	2043	47.50	47.69	95.19
21	2044	48.36	49.23	97.58
22	2045	49.23	50.74	99.97

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2024 MPSC Staff Combined Cycle Levelized Cost

Case No.: U-21662
Exhibit: A-20 Sch. A2
Witness: F. M. Kopinski
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Line No.	(a)	(b)	(c)	(d)	(e)	(f)
1	Levelized Cost Calculation					
2						
3		NGCC	*notes*			
4	Capacity MW	400	MW			
5	Loading Factor	71.00%	The % of time the unit would be dispatched if available			
6	Equivalent Avail.	87.00%	The % of time the unit would be available for dispatch. A combination of FOR and planned outages			
7	Capacity Factor	61.77%	(Loading Factor)(Equivalent Availability)			
8	Heat Rate Btu/kWh	6719	BTU/kWh			
9	Fuel Cost $/MBtu	$4.57	$ per thousand BTU			
10	Total Cost MM no AFUDC	$560.817	MM			
11	AFUDC	$76.68	MM			
12	Total Cost MM	$637.500	MM			
13	Fixed Charge Rate	11.59%	% used to calculate fixed cost recovery component			
14	Fixed O&M $/kW	$14.62	$/kW			
15	Annual Lev. Fixed Cost MM	$73.89	MM			
16	Total Annual Lev. Fixed Cost MM	$79.73	MM			
17	Fixed Cost $/kWh	0.0368	$/kWh			
18	Fuel Cost $/kWh	0.0307	$/kWh			
19	Var. O&M $/kWh	0.0031	$/kWh			
20	Total Var. Cost	0.0338	$/kWh			
21	Total Cost $/kWh	0.07068	$/kWh			
22						
23						
24						

25	**AFUDC**		**Total Overnight Cost (MM) in 2021 $**	**Inflation Rate**	**Cumulative**	**Finance Rate**
26	Year	GCC	$529.436	2%		6.56%
27	1	5%	26	27.00	27.00	1.77
28	2	30%	159	165.25	192.25	12.61
29	3	35%	185	196.64	388.89	25.51
30	4	30%	159	171.92	560.82	36.79
31		1	529	560.817		76.68

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
2024 MPSC Staff Combined Cycle Levelized Fuel Price

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Exhibit: A-20 Sch. A3
Witness: F. M. Kopinski
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Line No.	(a)	(b)	(c)
1		**Source: EIA Annual Energy Outlook 2022**	
2		http://www.eia.gov/	
3			Henry Hub 2021 Annual Energy Outlook
4		Period (Used for Levelized Calculation)	(Nominal)
5			
6	2023	1	$5.48
7	2024	2	$4.34
8	2025	3	$3.80
9	2026	4	$3.41
10	2027	5	$3.24
11	2028	6	$3.25
12	2029	7	$3.35
13	2030	8	$3.54
14	2031	9	$3.78
15	2032	10	$4.07
16	2033	11	$4.44
17	2034	12	$4.75
18	2035	13	$5.02
19	2036	14	$5.15
20	2037	15	$5.33
21	2038	16	$5.63
22	2039	17	$5.64
23	2040	18	$5.99
24	2041	19	$6.26
25	2042	20	$6.39
26	2043	21	$6.43
27	2044	22	$6.52
28	2045	23	$6.66
29	2046	24	$6.81
30	2047	25	$6.91
31	2048	26	$7.04
32	2049	27	$7.08
33	2050	28	$7.23
34			
35			
36	**Discount Rate**		**8.98%**
37	**Net Present Value Fuel**		**$46.35**
38	**Levelized Fuel Price**		**$4.57**

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
MPSC Staff Inflation Numbers

Case No.: U-21662
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Witness: F. M. Kopinski
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Line No.	(a) Year	(b) Inflation	(c) Percentage
1	2029	2.11	2.11%
2	2030	2.12	2.12%
3	2031	2.14	2.14%
4	2032	2.16	2.16%
5	2033	2.16	2.16%
6	2034	2.15	2.15%
7	2035	2.16	2.16%
8	2036	2.16	2.16%
9	2037	2.16	2.16%
10	2038	2.16	2.16%
11	2039	2.16	2.16%
12	2040	2.16	2.16%
13	2041	2.16	2.16%
14	2042	2.16	2.16%
15	2043	2.16	2.16%
16	2044	2.16	2.16%
17	2045	2.16	2.16%
18	2046	2.16	2.16%
19	2047	2.16	2.16%
20	2048	2.16	2.16%
21	2049	2.16	2.16%
22	2050	2.16	2.16%
23	2051	2.16	2.16%

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
1	**Compliance PPAs - Wind**														
1	Stoney Corners	Generation	**1,000 MWh**	78.1	66.2	76.3	76.1	76.1	76.1	76.3	76.1	-	-	-	-
2	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 8.3	$ 7.4	$ 8.9	$ 8.8	$ 8.8	$ 8.8	$ 8.9	$ 8.8	$ -	$ -	$ -	$ -
3	Gratiot	Generation	**1,000 MWh**	285.0	228.1	272.6	271.9	271.9	271.9	272.6	271.9	271.9	271.9	-	-
4	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 26.1	$ 20.9	$ 24.9	$ 24.9	$ 24.9	$ 24.9	$ 24.9	$ 24.9	$ 24.9	$ 24.9	$ -	$ -
5	Tuscola Bay Wind	Generation	**1,000 MWh**	384.7	327.9	365.8	364.8	364.8	364.8	365.8	364.8	364.8	364.8	365.8	-
6	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 23.4	$ 20.0	$ 22.3	$ 22.2	$ 22.2	$ 22.2	$ 22.3	$ 22.2	$ 22.2	$ 22.2	$ 22.3	$ -
7	Tuscola Wind II	Generation	**1,000 MWh**	307.4	261.8	300.2	299.4	299.4	299.4	300.2	299.4	299.4	299.4	300.2	299.4
8	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 15.1	$ 12.9	$ 14.8	$ 14.7	$ 14.7	$ 14.7	$ 14.8	$ 14.7	$ 14.7	$ 14.7	$ 14.8	$ 14.7
9	Pheasant Run	Generation	**1,000 MWh**	261.8	223.0	255.2	254.5	254.5	254.5	255.2	254.5	254.5	254.5	255.2	254.5
10	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 12.9	$ 11.0	$ 12.6	$ 12.5	$ 12.5	$ 12.5	$ 12.6	$ 12.5	$ 12.5	$ 12.5	$ 12.6	$ 12.5
11	Big Turtle	Generation	**1,000 MWh**	61.7	66.1	67.2	67.0	67.0	67.0	67.2	67.0	67.0	67.0	67.2	67.0
12	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 3.3	$ 3.5	$ 3.6	$ 3.5	$ 3.5	$ 3.5	$ 3.6	$ 3.5	$ 3.5	$ 3.5	$ 3.6	$ 3.5
13	2028 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	127.1	158.1	158.1	158.1	158.5	158.1
14	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.7	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6
15	2029 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	127.6	159.3	159.3	159.7	159.3
16	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.7	$ 9.6	$ 9.6	$ 9.6	$ 9.6
17	2030 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	128.6	160.4	160.9	160.4
18	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.6	$ 9.5	$ 9.6	$ 9.5
19	2031 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
20	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	2032 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
22	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		**Compliance PPAs - Wind Generation**	**1,000 MWh**	**1,378.7**	**1,173.2**	**1,337.2**	**1,333.6**	**1,333.6**	**1,333.6**	**1,464.3**	**1,619.4**	**1,703.5**	**1,735.3**	**1,467.4**	**1,098.7**
24		**Compliance PPAs - Wind PSCR Transfer Expense**	**$Mil**	**$ 89.1**	**$ 75.6**	**$ 87.0**	**$ 86.7**	**$ 86.7**	**$ 86.7**	**$ 94.7**	**$ 104.0**	**$ 104.7**	**$ 106.6**	**$ 81.9**	**$ 59.5**

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
1	**Compliance PPAs - Wind**														
1	Stoney Corners	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
2	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Gratiot	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
4	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Tuscola Bay Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
6	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Tuscola Wind II	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
8	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Pheasant Run	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
10	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Big Turtle	Generation	**1,000 MWh**	67.0	-	-	-	-	-	-	-	-	-	-	-
12	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 3.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	2028 PPA - IRP Wind	Generation	**1,000 MWh**	158.1	158.1	158.5	158.1	158.1	158.1	158.5	158.1	158.1	158.1	158.5	158.1
14	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6
15	2029 PPA - IRP Wind	Generation	**1,000 MWh**	159.3	159.3	159.7	159.3	159.3	159.3	159.7	159.3	159.3	159.3	159.7	159.3
16	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6	$ 9.6
17	2030 PPA - IRP Wind	Generation	**1,000 MWh**	160.4	160.4	160.9	160.4	160.4	160.4	160.9	160.4	160.4	160.4	160.9	160.4
18	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 9.5	$ 9.5	$ 9.6	$ 9.5	$ 9.5	$ 9.5	$ 9.6	$ 9.5	$ 9.5	$ 9.5	$ 9.6	$ 9.5
19	2031 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
20	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	2032 PPA - IRP Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
22	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23		**Compliance PPAs - Wind Generation**	**1,000 MWh**	**544.8**	**477.8**	**479.1**	**477.8**	**477.8**	**477.8**	**479.1**	**477.8**	**477.8**	**477.8**	**479.1**	**477.8**
24		**Compliance PPAs - Wind PSCR Transfer Expense**	**$Mil**	**$ 32.2**	**$ 28.7**	**$ 28.8**	**$ 28.7**	**$ 28.7**	**$ 28.7**	**$ 28.8**	**$ 28.7**	**$ 28.7**	**$ 28.7**	**$ 28.8**	**$ 28.7**

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	Compliance PPAs - Landfill Gas/Biomass														
25	L'Anse Warden	Generation	**1,000 MWh**	86.2	120.0	115.7	115.4	115.4	115.4	115.7	115.4	115.4	-	-	-
26	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 8.8	$ 12.2	$ 11.8	$ 11.8	$ 11.8	$ 11.8	$ 11.8	$ 11.8	$ 11.8	$ -	$ -	$ -
27	WM Renewable	Generation	**1,000 MWh**	24.0	21.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	-	-	-
28	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 2.0	$ 1.8	$ 2.1	$ 2.1	$ 2.1	$ 2.1	$ 2.1	$ 2.1	$ 2.1	$ -	$ -	$ -
29	Blue Water	Generation	**1,000 MWh**	25.2	24.7	26.0	25.9	25.9	25.9	26.0	25.9	25.9	25.9	-	-
30	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 2.5	$ 2.4	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ -	$ -
		Compliance PPAs - Landfill Gas/Biomass Generation		**135.4**	**166.1**	**166.2**	**165.7**	**165.7**	**165.7**	**166.2**	**165.7**	**165.7**	**25.9**	**-**	**-**
31		**Compliance PPAs - Landfill Gas/Biomass PSCR Transfer Expense**	**$Mil**	**$ 13.3**	**$ 16.5**	**$ 16.5**	**$ 16.4**	**$ 16.4**	**$ 16.4**	**$ 16.5**	**$ 16.4**	**$ 16.4**	**$ 2.6**	**$ -**	**$ -**
	Compliance PPAs - Solar														
32	River Fork - Ranger Power	Generation	**1,000 MWh**	-	-	74.9	100.3	99.8	99.3	99.1	98.3	97.8	97.3	97.1	96.3
33	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ 3.2	$ 4.4	$ 4.4	$ 4.5	$ 4.6	$ 4.6	$ 4.7	$ 4.8	$ 4.9	$ 4.9
34	Coldwater River	Generation	**1,000 MWh**	-	-	-	-	281.9	300.7	300.0	297.7	296.2	294.7	294.1	291.8
35	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 18.7	$ 20.4	$ 20.9	$ 21.4	$ 21.7	$ 21.9	$ 21.8	$ 21.7
36	White Pine Grove	Generation	**1,000 MWh**	-	-	-	-	171.6	183.0	182.6	181.2	180.3	179.4	179.0	177.6
37	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 11.4	$ 12.4	$ 12.7	$ 13.0	$ 13.2	$ 13.4	$ 13.7	$ 13.9
38	2026 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
39	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	2027 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	556.7	595.4	590.8	587.9	584.9	583.6	579.1
41	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 37.9	$ 41.6	$ 42.4	$ 43.1	$ 43.8	$ 44.7	$ 45.3
42	2028 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	221.1	235.1	234.0	232.8	232.3	230.5
43	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.4	$ 16.9	$ 17.2	$ 17.4	$ 17.8	$ 17.8
44	2029 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	443.8	473.4	471.0	469.9	466.3
45	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.9	$ 34.7	$ 34.7	$ 34.6	$ 34.4
46	2030 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	446.7	476.4	475.3	471.7
47	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31.8	$ 33.9	$ 33.8	$ 33.6
48	2031 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
49	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	2032 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
51	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52		**Compliance PPAs - Solar Generation**	**1,000 MWh**	**-**	**-**	**74.9**	**100.3**	**553.3**	**1,139.7**	**1,398.2**	**1,847.0**	**2,316.2**	**2,336.6**	**2,331.3**	**2,313.3**
53		**Compliance PPAs - Solar PSCR Transfer Expense**	**$Mil**	**$ -**	**$ -**	**$ 3.2**	**$ 4.4**	**$ 34.6**	**$ 75.3**	**$ 95.3**	**$ 130.2**	**$ 166.4**	**$ 170.0**	**$ 171.3**	**$ 171.5**
54		**TOTAL Generation - Compliance PPAs**	**1,000 MWh**	**1,514.1**	**1,339.3**	**1,578.3**	**1,599.6**	**2,052.6**	**2,639.0**	**3,028.7**	**3,632.0**	**4,185.3**	**4,097.8**	**3,798.7**	**3,412.0**
55		**TOTAL PSCR Transfer Expense - Compliance PPAs**	**$Mil**	**$ 102.4**	**$ 92.1**	**$ 106.6**	**$ 107.5**	**$ 137.7**	**$ 178.4**	**$ 206.4**	**$ 250.6**	**$ 287.5**	**$ 279.1**	**$ 253.2**	**$ 231.0**

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	Compliance PPAs - Landfill Gas/Biomass														
25	L'Anse Warden	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
26	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	WM Renewable	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
28	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Blue Water	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
30	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Compliance PPAs - Landfill Gas/Biomass Generation			-	-	-	-	-	-	-	-	-	-	-	-
31	**Compliance PPAs - Landfill Gas/Biomass PSCR Transfer Expense**		**$Mil**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Compliance PPAs - Solar														
32	River Fork - Ranger Power	Generation	**1,000 MWh**	95.9	95.4	95.2	94.4	94.0	93.5	93.3	92.6	92.1	91.6	91.4	90.7
33	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 5.0	$ 5.1	$ 5.2	$ 5.2	$ 5.3	$ 5.4	$ 5.5	$ 5.5	$ 5.6	$ 5.7	$ 5.8	$ 5.9
34	Coldwater River	Generation	**1,000 MWh**	290.3	288.9	288.2	286.0	284.6	283.2	282.5	280.3	278.9	277.5	276.9	274.8
35	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 21.5	$ 21.4	$ 21.4	$ 21.2	$ 21.1	$ 21.0	$ 21.0	$ 20.8	$ 20.7	$ 20.6	$ 20.5	$ 20.4
36	White Pine Grove	Generation	**1,000 MWh**	176.7	175.8	175.4	174.1	173.2	172.4	172.0	170.6	169.8	168.9	168.5	167.2
37	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 13.9	$ 13.9	$ 13.8	$ 13.7	$ 13.6	$ 13.6	$ 13.5	$ 13.4	$ 13.4	$ 13.3	$ 13.3	$ 13.2
38	2026 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
39	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	2027 PPA - IRP Solar	Generation	**1,000 MWh**	576.2	573.3	572.0	567.6	564.8	561.9	560.7	556.3	553.5	550.8	549.5	545.3
41	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 45.4	$ 45.2	$ 45.1	$ 44.7	$ 44.5	$ 44.3	$ 44.2	$ 43.9	$ 43.6	$ 43.4	$ 43.3	$ 43.0
42	2028 PPA - IRP Solar	Generation	**1,000 MWh**	229.3	228.2	227.7	225.9	224.8	223.7	223.1	221.4	220.3	219.2	218.7	217.0
43	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 17.7	$ 17.6	$ 17.6	$ 17.4	$ 17.4	$ 17.3	$ 17.2	$ 17.1	$ 17.0	$ 16.9	$ 16.9	$ 16.8
44	2029 PPA - IRP Solar	Generation	**1,000 MWh**	464.0	461.6	460.6	457.0	454.8	452.5	451.4	448.0	445.7	443.5	442.5	439.1
45	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 34.2	$ 34.0	$ 33.9	$ 33.7	$ 33.5	$ 33.3	$ 33.3	$ 33.0	$ 32.8	$ 32.7	$ 32.6	$ 32.4
46	2030 PPA - IRP Solar	Generation	**1,000 MWh**	469.3	467.0	465.9	462.3	460.0	457.7	456.7	453.1	450.9	448.6	447.6	444.1
47	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 33.4	$ 33.2	$ 33.1	$ 32.9	$ 32.7	$ 32.6	$ 32.5	$ 32.2	$ 32.1	$ 31.9	$ 31.8	$ 31.6
48	2031 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
49	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	2032 PPA - IRP Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
51	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	**Compliance PPAs - Solar Generation**		**1,000 MWh**	**2,301.7**	**2,290.2**	**2,285.0**	**2,267.4**	**2,256.0**	**2,244.7**	**2,239.6**	**2,222.4**	**2,211.2**	**2,200.2**	**2,195.2**	**2,178.2**
53	**Compliance PPAs - Solar PSCR Transfer Expense**		**$Mil**	**$ 171.2**	**$ 170.4**	**$ 170.1**	**$ 168.9**	**$ 168.2**	**$ 167.4**	**$ 167.2**	**$ 166.0**	**$ 165.2**	**$ 164.5**	**$ 164.3**	**$ 163.1**
54	**TOTAL Generation - Compliance PPAs**		**1,000 MWh**	**2,846.5**	**2,768.0**	**2,764.1**	**2,745.2**	**2,733.8**	**2,722.6**	**2,718.8**	**2,700.2**	**2,689.0**	**2,678.0**	**2,674.3**	**2,656.0**
55	**TOTAL PSCR Transfer Expense - Compliance PPAs**		**$Mil**	**$ 203.4**	**$ 199.1**	**$ 198.9**	**$ 197.6**	**$ 196.8**	**$ 196.1**	**$ 195.9**	**$ 194.7**	**$ 193.9**	**$ 193.2**	**$ 193.0**	**$ 191.8**

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	Compliance DTE Owned - Wind														
56	Gratiot County Wind	Generation	**1,000 MWh**	251.5	190.7	232.1	231.4	231.4	231.4	232.1	231.4	231.4	231.4	232.1	231.4
57	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 26.6	$ 21.2	$ 27.1	$ 27.4	$ 28.4	$ 29.6	$ 31.7	$ 32.9	$ 33.6	$ 34.3	$ 35.2	$ 35.8
58	Minden Wind Park	Generation	**1,000 MWh**	118.5	104.0	113.2	112.9	112.9	112.9	113.2	112.9	112.9	112.9	113.2	112.9
59	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 12.5	$ 11.5	$ 13.2	$ 13.4	$ 13.9	$ 14.4	$ 15.5	$ 16.1	$ 16.4	$ 16.8	$ 17.2	$ 17.5
60	McKinley Wind Park	Generation	**1,000 MWh**	53.1	48.6	52.0	51.8	51.8	51.8	52.0	51.8	51.8	51.8	52.0	51.8
61	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 5.6	$ 5.4	$ 6.1	$ 6.1	$ 6.4	$ 6.6	$ 7.1	$ 7.4	$ 7.5	$ 7.7	$ 7.9	$ 8.0
62	Sigel Wind Park	Generation	**1,000 MWh**	257.1	228.3	250.1	249.4	249.4	249.4	250.1	249.4	249.4	249.4	250.1	249.4
63	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 27.2	$ 25.4	$ 29.2	$ 29.5	$ 30.6	$ 31.9	$ 34.1	$ 35.5	$ 36.2	$ 37.0	$ 37.9	$ 38.6
64	Echo Wind Park	Generation	**1,000 MWh**	406.4	356.3	388.9	387.9	387.9	387.9	388.9	387.9	387.9	387.9	388.9	387.9
65	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 31.4	$ 28.1	$ 31.3	$ 31.9	$ 32.5	$ 32.8	$ 33.5	$ 34.0	$ 34.7	$ 35.5	$ 36.3	$ 37.0
66	Brookfield Wind Park	Generation	**1,000 MWh**	263.5	218.6	251.1	250.4	250.4	250.4	251.1	250.4	250.4	250.4	251.1	250.4
67	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.4	$ 17.2	$ 20.2	$ 20.6	$ 21.0	$ 21.2	$ 21.6	$ 21.9	$ 22.4	$ 22.9	$ 23.5	$ 23.9
68	Pinnebog Wind Park	Generation	**1,000 MWh**	182.7	161.2	170.9	170.4	170.4	170.4	170.9	170.4	170.4	170.4	170.9	170.4
69	2014 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 11.6	$ 12.9	$ 13.8	$ 14.1	$ 14.5	$ 14.8	$ 15.2	$ 15.4	$ 15.7	$ 16.1	$ 16.5	$ 16.8
70	Pine River Wind Park	Generation	**1,000 MWh**	420.1	345.2	346.8	392.4	392.4	392.4	393.4	392.4	392.4	392.4	393.4	392.4
71	2015 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 34.3	$ 28.8	$ 29.4	$ 34.0	$ 34.6	$ 35.3	$ 36.5	$ 37.1	$ 37.9	$ 38.7	$ 39.6	$ 40.4
72	Polaris Wind Park	Generation	**1,000 MWh**	498.9	412.9	415.5	465.8	465.8	465.8	467.1	465.8	465.8	465.8	467.1	465.8
73	2016 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 44.3	$ 37.1	$ 38.1	$ 43.5	$ 44.0	$ 45.0	$ 45.8	$ 46.5	$ 47.5	$ 48.5	$ 49.7	$ 50.6
74	Meridian	Generation	**1,000 MWh**	238.7	418.6	564.1	562.6	562.6	562.6	564.1	562.6	562.6	562.6	564.1	562.6
75	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 15.9	$ 28.8	$ 40.4	$ 41.4	$ 42.3	$ 43.5	$ 45.1	$ 47.0	$ 48.0	$ 49.0	$ 50.2	$ 51.1
76	2028 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	308.3	368.9	368.9	368.9	369.9	368.9
77	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 21.5	$ 26.5	$ 27.1	$ 27.6	$ 28.3	$ 28.8
78	2029 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	309.7	371.6	371.6	372.6	371.6
79	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22.2	$ 27.3	$ 27.8	$ 28.5	$ 29.1
80	2030 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	311.9	374.3	375.3	374.3
81	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22.9	$ 28.0	$ 28.7	$ 29.3
82	2031 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	446.0	536.6	535.2
83	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33.4	$ 41.1	$ 41.8
84	2032 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	447.6	535.6
85	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.3	$ 41.9
86	2033 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	446.7
87	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34.9
88	2034 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
89	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	2035 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
91	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	2036 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
93	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	2037 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
95	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	2038 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
97	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	2039 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
99	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	2040 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
101	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	2041 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
103	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	2042 IRP Build Wind	Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
105	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106		**Compliance DTE Owned - Wind Generation**	**1,000 MWh**	**2,690.5**	**2,484.3**	**2,784.7**	**2,875.0**	**2,875.0**	**2,875.0**	**3,191.1**	**3,553.6**	**3,927.5**	**4,435.8**	**4,985.0**	**5,507.3**
107		**Compliance DTE Owned - Wind PSCR Transfer Expense**	**$Mil**	**$ 229.8**	**$ 216.4**	**$ 249.0**	**$ 261.9**	**$ 268.2**	**$ 275.1**	**$ 307.6**	**$ 342.6**	**$ 377.2**	**$ 423.4**	**$ 474.8**	**$ 525.7**

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	Compliance DTE Owned - Wind														
56	Gratiot County Wind	Generation	**1,000 MWh**	231.4	231.4	232.1	231.4	231.4	231.4	232.1	231.4	231.4	231.4	232.1	231.4
57	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 21.7	$ 21.7	$ 21.8	$ 21.7	$ 21.7	$ 21.7	$ 21.8	$ 21.7	$ 21.7	$ 21.7	$ 21.8	$ 21.7
58	Minden Wind Park	Generation	**1,000 MWh**	112.9	112.9	113.2	112.9	112.9	112.9	113.2	112.9	112.9	112.9	113.2	112.9
59	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5	$ 7.5
60	McKinley Wind Park	Generation	**1,000 MWh**	51.8	51.8	52.0	51.8	51.8	51.8	52.0	51.8	51.8	51.8	52.0	51.8
61	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 3.4	$ 3.4	$ 3.5	$ 3.4	$ 3.4	$ 3.4	$ 3.5	$ 3.4	$ 3.4	$ 3.4	$ 3.5	$ 3.4
62	Sigel Wind Park	Generation	**1,000 MWh**	249.4	249.4	250.1	249.4	249.4	249.4	250.1	249.4	249.4	249.4	250.1	249.4
63	U-15806 Transfer Price	Transfer Amount to PSCR	**$Mil**	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6	$ 16.6
64	Echo Wind Park	Generation	**1,000 MWh**	387.9	387.9	388.9	387.9	387.9	387.9	388.9	387.9	387.9	387.9	388.9	387.9
65	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 22.7	$ 22.7	$ 22.8	$ 22.7	$ 22.7	$ 22.7	$ 22.8	$ 22.7	$ 22.7	$ 22.7	$ 22.8	$ 22.7
66	Brookfield Wind Park	Generation	**1,000 MWh**	250.4	250.4	251.1	250.4	250.4	250.4	251.1	250.4	250.4	250.4	251.1	250.4
67	2012 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0	$ 13.0
68	Pinnebog Wind Park	Generation	**1,000 MWh**	170.4	170.4	170.9	170.4	170.4	170.4	170.9	170.4	170.4	170.4	170.9	170.4
69	2014 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 9.3	$ 9.3	$ 9.4	$ 9.3	$ 9.3	$ 9.3	$ 9.4	$ 9.3	$ 9.3	$ 9.3	$ 9.4	$ 9.3
70	Pine River Wind Park	Generation	**1,000 MWh**	392.4	392.4	393.4	392.4	392.4	392.4	393.4	392.4	392.4	392.4	393.4	392.4
71	2015 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.4	$ 20.4	$ 20.5	$ 20.4	$ 20.4	$ 20.4	$ 20.5	$ 20.4	$ 20.4	$ 20.4	$ 20.5	$ 20.4
72	Polaris Wind Park	Generation	**1,000 MWh**	465.8	465.8	467.1	465.8	465.8	465.8	467.1	465.8	465.8	465.8	467.1	465.8
73	2016 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 21.4	$ 21.4	$ 21.5	$ 21.4	$ 21.4	$ 21.4	$ 21.5	$ 21.4	$ 21.4	$ 21.4	$ 21.5	$ 21.4
74	Meridian	Generation	**1,000 MWh**	562.6	562.6	564.1	562.6	562.6	562.6	564.1	562.6	562.6	562.6	564.1	562.6
75	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3	$ 25.3
76	2028 IRP Build Wind	Generation	**1,000 MWh**	368.9	368.9	369.9	368.9	368.9	368.9	369.9	368.9	368.9	368.9	369.9	368.9
77	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6	$ 20.6
78	2029 IRP Build Wind	Generation	**1,000 MWh**	371.6	371.6	372.6	371.6	371.6	371.6	372.6	371.6	371.6	371.6	372.6	371.6
79	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.5	$ 20.5	$ 20.6	$ 20.5	$ 20.5	$ 20.5	$ 20.6	$ 20.5	$ 20.5	$ 20.5	$ 20.6	$ 20.5
80	2030 IRP Build Wind	Generation	**1,000 MWh**	374.3	374.3	375.3	374.3	374.3	374.3	375.3	374.3	374.3	374.3	375.3	374.3
81	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.5	$ 20.5	$ 20.6	$ 20.5	$ 20.5	$ 20.5	$ 20.6	$ 20.5	$ 20.5	$ 20.5	$ 20.6	$ 20.5
82	2031 IRP Build Wind	Generation	**1,000 MWh**	535.2	535.2	536.6	535.2	535.2	535.2	536.6	535.2	535.2	535.2	536.6	535.2
83	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 29.4	$ 29.4	$ 29.5	$ 29.4	$ 29.4	$ 29.4	$ 29.5	$ 29.4	$ 29.4	$ 29.4	$ 29.5	$ 29.4
84	2032 IRP Build Wind	Generation	**1,000 MWh**	535.6	535.6	537.1	535.6	535.6	535.6	537.1	535.6	535.6	535.6	537.1	535.6
85	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 30.0	$ 30.0	$ 30.1	$ 30.0	$ 30.0	$ 30.0	$ 30.1	$ 30.0	$ 30.0	$ 30.0	$ 30.1	$ 30.0
86	2033 IRP Build Wind	Generation	**1,000 MWh**	536.0	536.0	537.5	536.0	536.0	536.0	537.5	536.0	536.0	536.0	537.5	536.0
87	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 30.5	$ 30.5	$ 30.6	$ 30.5	$ 30.5	$ 30.5	$ 30.6	$ 30.5	$ 30.5	$ 30.5	$ 30.6	$ 30.5
88	2034 IRP Build Wind	Generation	**1,000 MWh**	447.1	536.5	537.9	536.5	536.5	536.5	537.9	536.5	536.5	536.5	537.9	536.5
89	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 25.8	$ 31.0	$ 31.1	$ 31.0	$ 31.0	$ 31.0	$ 31.1	$ 31.0	$ 31.0	$ 31.0	$ 31.1	$ 31.0
90	2035 IRP Build Wind	Generation	**1,000 MWh**	-	2,237.1	2,691.8	2,684.5	2,684.5	2,684.5	2,691.8	2,684.5	2,684.5	2,684.5	2,691.8	2,684.5
91	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ 128.6	$ 154.8	$ 154.3	$ 154.3	$ 154.3	$ 154.8	$ 154.3	$ 154.3	$ 154.3	$ 154.8	$ 154.3
92	2036 IRP Build Wind	Generation	**1,000 MWh**	-	-	2,245.0	2,686.7	2,686.7	2,686.7	2,694.0	2,686.7	2,686.7	2,686.7	2,694.0	2,686.7
93	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ 131.5	$ 157.4	$ 157.4	$ 157.4	$ 157.8	$ 157.4	$ 157.4	$ 157.4	$ 157.8	$ 157.4
94	2037 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	2,240.7	2,688.8	2,688.8	2,696.2	2,688.8	2,688.8	2,688.8	2,696.2	2,688.8
95	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ 133.7	$ 160.4	$ 160.4	$ 160.9	$ 160.4	$ 160.4	$ 160.4	$ 160.9	$ 160.4
96	2038 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	2,242.5	2,691.0	2,698.3	2,691.0	2,691.0	2,691.0	2,698.3	2,691.0
97	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 136.3	$ 163.5	$ 164.0	$ 163.5	$ 163.5	$ 163.5	$ 164.0	$ 163.5
98	2039 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	2,244.3	2,700.5	2,693.1	2,693.1	2,693.1	2,700.5	2,693.1
99	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 138.6	$ 166.7	$ 166.3	$ 166.3	$ 166.3	$ 166.7	$ 166.3
100	2040 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	2,252.2	2,695.3	2,695.3	2,695.3	2,702.7	2,695.3
101	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 141.8	$ 169.8	$ 169.8	$ 169.8	$ 170.2	$ 169.8
102	2041 IRP Build Wind	Generation	**1,000 MWh**	-	-	-	-	-	-	-	2,247.9	2,697.5	2,697.5	2,704.8	2,697.5
103	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 144.4	$ 173.3	$ 173.3	$ 173.7	$ 173.3
104	2042 IRP Build Wind	Subscribed Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	1,124.8	1,349.8	1,353.5	1,349.8
105	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74.1	$ 88.9	$ 89.1	$ 88.9
106		**Compliance DTE Owned - Wind Generation**	**1,000 MWh**	**6,043.7**	**8,370.2**	**11,086.8**	**13,744.9**	**16,435.5**	**19,128.3**	**21,883.0**	**24,520.3**	**26,094.8**	**26,319.7**	**26,391.8**	**26,319.7**
107		**Compliance DTE Owned - Wind PSCR Transfer Expense**	**$Mil**	**$ 338.7**	**$ 472.4**	**$ 631.0**	**$ 789.2**	**$ 952.3**	**$ 1,118.1**	**$ 1,290.8**	**$ 1,459.9**	**$ 1,562.9**	**$ 1,577.7**	**$ 1,582.0**	**$ 1,577.7**

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	Compliance DTE Owned - Solar														
108	DTE Solar Currents I	Generation	**1,000 MWh**	13.8	12.7	13.8	13.7	13.6	13.5	13.5	13.4	13.3	13.3	13.2	13.1
109	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 3.8	$ 3.7	$ 4.1	$ 4.2	$ 4.4	$ 4.5	$ 4.7	$ 4.9	$ 5.0	$ 5.1	$ 5.2	$ 5.2
110	DTE Solar Currents II	Generation	**1,000 MWh**	1.5	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
111	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
112	Demille/Turrill/O'Shea Utility-Scale Sola	Generation	**1,000 MWh**	66.3	64.6	66.7	66.2	65.8	65.5	65.3	64.8	64.5	64.2	64.0	63.6
113	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 5.2	$ 5.2	$ 5.4	$ 5.5	$ 5.6	$ 5.7	$ 5.8	$ 5.9	$ 6.0	$ 6.1	$ 6.2	$ 6.3
114	Ford Rooftop Solar Pilot	Generation	**1,000 MWh**	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8
115	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
116	2024 Future Solar Pilot	Generation	**1,000 MWh**	-	-	3.2	19.8	19.7	19.6	19.5	19.4	19.3	19.2	19.2	19.0
117	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ 0.2	$ 1.3	$ 1.3	$ 1.3	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.5	$ 1.5
118	Cedar Fields	Generation	**1,000 MWh**	-	-	-	-	-	171.4	276.6	274.5	273.1	271.7	271.1	269.0
119	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 11.7	$ 19.3	$ 19.7	$ 20.0	$ 20.4	$ 20.7	$ 19.4
120	2027 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	925.6	989.7	982.1	977.2	972.3	970.1	962.6
121	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 62.9	$ 69.1	$ 70.5	$ 71.7	$ 72.8	$ 74.2	$ 69.6
122	2028 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	515.9	548.7	545.9	543.2	542.0	537.8
123	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 36.0	$ 39.4	$ 40.0	$ 40.7	$ 41.5	$ 38.1
124	2029 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	1,035.7	1,104.5	1,099.0	1,096.5	1,088.0
125	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 74.4	$ 81.0	$ 82.3	$ 83.9	$ 73.5
126	2030 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	1,042.4	1,111.6	1,109.1	1,100.6
127	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76.5	$ 83.3	$ 84.9	$ 71.7
128	2031 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	1,498.7	1,602.6	1,590.3
129	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 112.3	$ 122.7	$ 99.4
130	2032 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	756.2	804.2
131	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 57.9	$ 48.7
132	2033 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	1,517.9
133	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 87.0
134	2034 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
135	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	2042 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
137	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138		**Compliance DTE Owned - Solar Generation**	**1,000 MWh**	**82.6**	**79.7**	**85.9**	**101.8**	**101.3**	**1,197.8**	**1,882.9**	**2,940.8**	**4,042.5**	**5,595.4**	**6,446.2**	**7,968.2**
139		**Compliance DTE Owned - Solar PSCR Transfer Expense**	**$Mil**	**$ 9.2**	**$ 9.0**	**$ 9.9**	**$ 11.2**	**$ 11.5**	**$ 86.3**	**$ 136.5**	**$ 216.4**	**$ 301.8**	**$ 424.5**	**$ 498.8**	**$ 520.4**
140		**TOTAL Generation - Compliance DTE Owned**	**1,000 MWh**	**2,773.1**	**2,564.0**	**2,870.5**	**2,976.8**	**2,976.3**	**4,072.8**	**5,074.0**	**6,494.4**	**7,969.9**	**10,031.2**	**11,431.2**	**13,475.5**
141		**TOTAL PSCR Transfer Expense - Compliance Owned**	**$Mil**	**$ 239.0**	**$ 225.5**	**$ 258.9**	**$ 273.1**	**$ 279.6**	**$ 361.4**	**$ 444.0**	**$ 559.0**	**$ 679.0**	**$ 847.9**	**$ 973.6**	**$ 1,046.1**
142		**Compliance TOTAL Generation**	**1,000 MWh**	**4,287.2**	**3,903.3**	**4,448.8**	**4,576.4**	**5,028.9**	**6,711.8**	**8,102.6**	**10,126.4**	**12,155.3**	**14,129.1**	**15,229.9**	**16,887.5**
143		**Compliance TOTAL PSCR Transfer Expense**	**$Mil**	**$ 341.4**	**$ 317.5**	**$ 365.5**	**$ 380.6**	**$ 417.3**	**$ 539.8**	**$ 650.4**	**$ 809.6**	**$ 966.5**	**$ 1,127.0**	**$ 1,226.9**	**$ 1,277.0**

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	Compliance DTE Owned - Solar														
108	DTE Solar Currents I	Generation	**1,000 MWh**	13.1	13.0	13.0	12.9	12.8	12.8	12.7	12.6	12.6	12.5	12.5	12.4
109	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 5.3	$ 5.4	$ 5.5	$ 5.6	$ 5.7	$ 5.8	$ 5.9	$ 6.0	$ 6.1	$ 6.2	$ 6.3	$ 6.4
110	DTE Solar Currents II	Generation	**1,000 MWh**	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
111	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
112	Demille/Turrill/O'Shea Utility-Scale Sola	Generation	**1,000 MWh**	63.2	62.9	62.8	62.3	62.0	61.7	61.5	61.1	60.8	60.4	60.3	59.8
113	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 6.4	$ 6.5	$ 6.6	$ 6.7	$ 6.8	$ 6.9	$ 7.0	$ 7.1	$ 7.2	$ 7.4	$ 7.5	$ 7.6
114	Ford Rooftop Solar Pilot	Generation	**1,000 MWh**	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
115	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
116	2024 Future Solar Pilot	Generation	**1,000 MWh**	18.9	18.8	18.8	18.6	18.5	18.4	18.4	18.3	18.2	18.1	18.0	17.9
117	Transfer Amount to PSCR	Transfer Amount to PSCR	**$Mil**	$ 1.5	$ 1.5	$ 1.6	$ 1.6	$ 1.6	$ 1.6	$ 1.7	$ 1.7	$ 1.7	$ 1.7	$ 1.8	$ 1.8
118	Cedar Fields	Generation	**1,000 MWh**	267.7	266.3	265.7	263.7	262.4	261.1	260.5	258.4	257.2	255.9	255.3	253.3
119	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 19.3	$ 19.2	$ 19.1	$ 19.0	$ 18.9	$ 18.8	$ 18.7	$ 18.6	$ 18.5	$ 18.4	$ 18.4	$ 18.2
120	2027 IRP Build Solar	Generation	**1,000 MWh**	957.8	953.0	950.8	943.5	938.8	934.1	932.0	924.8	920.2	915.5	913.5	906.4
121	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 69.2	$ 68.9	$ 68.7	$ 68.2	$ 67.9	$ 67.5	$ 67.4	$ 66.9	$ 66.5	$ 66.2	$ 66.0	$ 65.5
122	2028 IRP Build Solar	Generation	**1,000 MWh**	535.1	532.4	531.2	527.1	524.5	521.9	520.7	516.7	514.1	511.5	510.3	506.4
123	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 37.9	$ 37.7	$ 37.6	$ 37.3	$ 37.1	$ 36.9	$ 36.9	$ 36.6	$ 36.4	$ 36.2	$ 36.1	$ 35.9
124	2029 IRP Build Solar	Generation	**1,000 MWh**	1,082.6	1,077.2	1,074.7	1,066.4	1,061.1	1,055.8	1,053.4	1,045.3	1,040.0	1,034.8	1,032.5	1,024.5
125	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 73.1	$ 72.7	$ 72.6	$ 72.0	$ 71.7	$ 71.3	$ 71.1	$ 70.6	$ 70.2	$ 69.9	$ 69.7	$ 69.2
126	2030 IRP Build Solar	Generation	**1,000 MWh**	1,095.1	1,089.6	1,087.1	1,078.7	1,073.3	1,067.9	1,065.5	1,057.3	1,052.0	1,046.7	1,044.4	1,036.3
127	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 71.4	$ 71.0	$ 70.9	$ 70.3	$ 70.0	$ 69.6	$ 69.4	$ 68.9	$ 68.6	$ 68.2	$ 68.1	$ 67.5
128	2031 IRP Build Solar	Generation	**1,000 MWh**	1,582.3	1,574.4	1,570.8	1,558.7	1,550.9	1,543.2	1,539.6	1,527.8	1,520.1	1,512.5	1,509.1	1,497.4
129	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 126.4	$ 98.4	$ 98.1	$ 97.4	$ 96.9	$ 96.4	$ 96.2	$ 95.5	$ 95.0	$ 94.5	$ 94.3	$ 93.6
130	2032 IRP Build Solar	Generation	**1,000 MWh**	800.2	796.2	794.4	788.3	784.3	780.4	778.6	772.6	768.8	764.9	763.2	757.3
131	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 48.4	$ 48.2	$ 48.1	$ 47.7	$ 47.5	$ 47.2	$ 47.1	$ 46.7	$ 46.5	$ 46.3	$ 46.2	$ 45.8
132	2033 IRP Build Solar	Generation	**1,000 MWh**	1,618.7	1,610.6	1,606.9	1,594.5	1,586.5	1,578.6	1,575.0	1,562.9	1,555.0	1,547.3	1,543.7	1,531.8
133	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 92.8	$ 92.3	$ 92.1	$ 91.4	$ 90.9	$ 90.5	$ 90.3	$ 89.6	$ 89.1	$ 88.7	$ 88.5	$ 87.8
134	2034 IRP Build Solar	Generation	**1,000 MWh**	1,527.4	1,628.9	1,625.2	1,612.6	1,604.6	1,596.5	1,592.9	1,580.6	1,572.7	1,564.8	1,561.3	1,549.2
135	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 83.1	$ 88.7	$ 88.5	$ 87.8	$ 87.3	$ 86.9	$ 86.7	$ 86.0	$ 85.6	$ 85.2	$ 85.0	$ 84.3
136	2042 IRP Build Solar	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	882.9	1,054.1	1,051.7	1,043.6
137	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43.2	$ 51.6	$ 51.5	$ 51.1
138		**Compliance DTE Owned - Solar Generation**	**1,000 MWh**	**9,564.2**	**9,625.4**	**9,603.5**	**9,529.4**	**9,481.8**	**9,434.4**	**9,412.9**	**9,340.2**	**10,176.4**	**10,301.2**	**10,277.8**	**10,198.5**
139		**Compliance DTE Owned - Solar PSCR Transfer Expense**	**$Mil**	**$ 635.0**	**$ 610.6**	**$ 609.5**	**$ 605.1**	**$ 602.4**	**$ 599.7**	**$ 598.7**	**$ 594.4**	**$ 634.9**	**$ 640.7**	**$ 639.6**	**$ 635.0**
140		**TOTAL Generation - Compliance DTE Owned**	**1,000 MWh**	**15,607.9**	**17,995.6**	**20,690.3**	**23,274.3**	**25,917.3**	**28,562.7**	**31,295.9**	**33,860.6**	**36,271.2**	**36,620.9**	**36,669.6**	**36,518.2**
141		**TOTAL PSCR Transfer Expense - Compliance Owned**	**$Mil**	**$ 973.6**	**$ 1,083.1**	**$ 1,240.6**	**$ 1,394.4**	**$ 1,554.7**	**$ 1,717.8**	**$ 1,889.5**	**$ 2,054.3**	**$ 2,197.8**	**$ 2,218.4**	**$ 2,221.6**	**$ 2,212.6**
142		**Compliance TOTAL Generation**	**1,000 MWh**	**18,454.4**	**20,763.6**	**23,454.4**	**26,019.5**	**28,651.1**	**31,285.2**	**34,014.7**	**36,560.8**	**38,960.2**	**39,298.9**	**39,343.9**	**39,174.2**
143		**Compliance TOTAL PSCR Transfer Expense**	**$Mil**	**$ 1,177.0**	**$ 1,282.2**	**$ 1,439.5**	**$ 1,592.0**	**$ 1,751.5**	**$ 1,913.9**	**$ 2,085.4**	**$ 2,249.0**	**$ 2,391.7**	**$ 2,411.6**	**$ 2,414.6**	**$ 2,404.4**

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	VGP PPAs - Solar														
144	Assembly - Ranger Power VGP	Generation	**1,000 MWh**	149.8	152.7	161.1	159.9	159.1	158.3	157.9	156.7	155.9	155.1	154.8	153.6
145	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 6.0	$ 6.1	$ 6.6	$ 6.6	$ 6.7	$ 6.8	$ 7.0	$ 7.1	$ 7.2	$ 7.3	$ 7.4	$ 7.5
146	2027 Unapproved PPA VGP	Generation	**1,000 MWh**	-	-	-	-	-	182.5	195.2	193.7	192.7	191.8	191.3	189.9
147	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 12.4	$ 13.6	$ 13.9	$ 14.1	$ 14.4	$ 14.6	$ 14.8
148	2028 Unapproved PPA VGP	Generation	**1,000 MWh**	-	-	-	-	-	-	305.8	325.3	323.7	322.0	321.3	318.8
149	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 21.3	$ 23.4	$ 23.7	$ 24.1	$ 24.6	$ 24.8
150	2029 Unapproved PPA VGP	Generation	**1,000 MWh**	-	-	-	-	-	-	-	79.5	84.8	84.4	84.2	83.5
151	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5.7	$ 6.2	$ 6.3	$ 6.4	$ 6.5
152		**VGP PPA - Total Generation**	**1,000 MWh**	149.8	152.7	161.1	159.9	159.1	340.8	658.9	755.2	757.1	753.3	751.6	745.8
	VGP DTE Owned Wind														
153	Isabella I	Generation	**1,000 MWh**	371.0	330.9	452.3	451.1	451.1	451.1	452.3	451.1	451.1	451.1	452.3	451.1
154	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 18.8	$ 16.7	$ 22.9	$ 22.8	$ 22.8	$ 22.8	$ 22.9	$ 22.8	$ 22.8	$ 22.8	$ 22.9	$ 22.8
155	Isabella II	Generation	**1,000 MWh**	409.0	344.8	414.1	413.0	413.0	413.0	414.1	413.0	413.0	413.0	414.1	413.0
156	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.7	$ 17.4	$ 21.0	$ 20.9	$ 20.9	$ 20.9	$ 21.0	$ 20.9	$ 20.9	$ 20.9	$ 21.0	$ 20.9
157	Fairbanks	Generation	**1,000 MWh**	214.5	193.7	193.1	192.6	192.6	192.6	193.1	192.6	192.6	192.6	193.1	192.6
158	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 9.7	$ 8.8	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7
159	Big Turtle II	Generation	**1,000 MWh**	-	62.1	94.7	94.4	94.4	103.0	103.0	103.0	103.0	103.0	103.0	103.0
160	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ 3.1	$ 4.7	$ 4.7	$ 4.7	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	VGP PPAs - Solar														
144	Assembly - Ranger Power VGP	Generation	**1,000 MWh**	152.8	152.1	151.7	150.5	149.8	149.0	148.7	147.6	146.8	146.1	145.8	144.6
145	2019 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 7.6	$ 7.7	$ 7.8	$ 7.9	$ 8.1	$ 8.2	$ 8.3	$ 8.4	$ 8.5	$ 8.7	$ 8.8	$ 8.9
146	2027 Unapproved PPA VGP	Generation	**1,000 MWh**	188.9	188.0	187.5	186.1	185.2	184.2	183.8	182.4	181.5	180.6	180.2	178.8
147	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 15.1	$ 15.3	$ 15.3	$ 15.1	$ 15.1	$ 15.0	$ 15.0	$ 14.8	$ 14.8	$ 14.7	$ 14.7	$ 14.5
148	2028 Unapproved PPA VGP	Generation	**1,000 MWh**	317.2	315.7	314.9	312.5	310.9	309.4	308.7	306.3	304.8	303.2	302.6	300.2
149	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 24.7	$ 24.6	$ 24.5	$ 24.3	$ 24.2	$ 24.1	$ 24.0	$ 23.9	$ 23.7	$ 23.6	$ 23.6	$ 23.4
150	2029 Unapproved PPA VGP	Generation	**1,000 MWh**	83.1	82.7	82.5	81.9	81.5	81.1	80.9	80.3	79.9	79.5	79.3	78.7
151	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 6.6	$ 6.5	$ 6.5	$ 6.5	$ 6.4	$ 6.4	$ 6.4	$ 6.3	$ 6.3	$ 6.3	$ 6.3	$ 6.2
152		**VGP PPA - Total Generation**	**1,000 MWh**	742.1	738.4	736.7	731.0	727.4	723.7	722.1	716.5	712.9	709.4	707.8	702.3
	VGP DTE Owned Wind														
153	Isabella I	Generation	**1,000 MWh**	451.1	451.1	452.3	451.1	451.1	451.1	452.3	451.1	451.1	451.1	452.3	451.1
154	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 22.8	$ 22.8	$ 22.9	$ 22.8	$ 22.8	$ 22.8	$ 22.9	$ 22.8	$ 22.8	$ 22.8	$ 22.9	$ 22.8
155	Isabella II	Generation	**1,000 MWh**	413.0	413.0	414.1	413.0	413.0	413.0	414.1	413.0	413.0	413.0	414.1	413.0
156	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 20.9	$ 20.9	$ 21.0	$ 20.9	$ 20.9	$ 20.9	$ 21.0	$ 20.9	$ 20.9	$ 20.9	$ 21.0	$ 20.9
157	Fairbanks	Generation	**1,000 MWh**	192.6	192.6	193.1	192.6	192.6	192.6	193.1	192.6	192.6	192.6	193.1	192.6
158	2018 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7	$ 8.7
159	Big Turtle II	Generation	**1,000 MWh**	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0	103.0
160	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1	$ 5.1

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	VGP DTE Owned Solar														
161	Gratiot Solar	Generation	**1,000 MWh**	-	-	-	-	92.3	94.5	94.6	94.6	94.6	94.7	94.7	94.7
162	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 6.5	$ 6.8	$ 7.0	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2
163	Pine River Solar	Generation	**1,000 MWh**	-	-	-	152.3	152.4	152.4	152.4	152.5	152.5	152.5	152.5	152.6
164	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0
165	Polaris Solar	Generation	**1,000 MWh**	-	-	-	173.5	186.1	186.1	186.1	186.2	186.2	186.2	186.2	186.3
166	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ 11.1	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9
167	Sauk Solar	Generation	**1,000 MWh**	-	-	-	307.9	306.3	304.8	304.1	301.8	300.3	298.7	298.1	295.8
168	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ 16.8	$ 16.7	$ 16.6	$ 16.6	$ 16.4	$ 16.3	$ 16.3	$ 16.2	$ 16.1
169	Wheeler Center - Customer Requested	Generation	**1,000 MWh**	-	-	-	27.6	27.4	27.3	27.2	27.0	26.9	26.7	26.7	26.5
170	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ 1.8	$ 1.8	$ 1.9	$ 1.9	$ 1.9	$ 2.0	$ 2.0	$ 2.0	$ 2.1
171	Ford I - 2024 - Customer Requested - P	Generation	**1,000 MWh**	-	-	-	-	-	396.4	424.0	420.7	418.6	416.5	415.6	412.4
172	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 23.0	$ 24.6	$ 24.4	$ 24.3	$ 24.2	$ 24.1	$ 24.0
173	Ford I - 2024 - Customer Requested - P	Generation	**1,000 MWh**	-	-	-	-	98.8	198.3	197.8	196.3	195.3	194.4	193.9	192.4
174	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 6.4	$ 12.9	$ 12.8	$ 12.8	$ 12.7	$ 12.6	$ 12.6	$ 12.5
175	Ford II - 2025 - Customer Requested - F	Generation	**1,000 MWh**	-	-	-	-	71.6	274.6	273.9	271.8	270.5	269.1	268.5	266.4
176	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 4.2	$ 16.2	$ 16.1	$ 16.0	$ 15.9	$ 15.8	$ 15.8	$ 15.7
177	Ford II - 2025 - Customer Requested - F	Generation	**1,000 MWh**	-	-	-	-	-	424.4	454.0	450.5	448.2	446.0	444.9	441.5
178	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 25.4	$ 27.2	$ 26.9	$ 26.8	$ 26.7	$ 26.6	$ 26.4
179	2027 Project 1 - Customer Requested	Generation	**1,000 MWh**	-	-	-	-	-	-	244.3	392.0	390.0	388.1	387.2	384.2
180	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 15.1	$ 24.3	$ 24.2	$ 24.1	$ 24.0	$ 23.8
181	Unnamed - 2025 - Customer Requestec	Generation	**1,000 MWh**	-	-	-	-	-	349.8	349.0	346.3	344.6	342.8	342.1	339.4
182	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 22.0	$ 22.0	$ 21.8	$ 21.7	$ 21.6	$ 21.5	$ 21.4
183	Unknown Approved - Unnamed - Custo	Generation	**1,000 MWh**	-	-	-	-	-	232.9	232.4	230.6	229.4	228.3	227.7	226.0
184	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 15.3	$ 15.3	$ 15.1	$ 15.1	$ 15.0	$ 15.0	$ 14.8
185	2028 Project 1 - Customer Requested	Generation	**1,000 MWh**	-	-	-	-	-	-	-	396.5	394.5	392.6	391.7	388.7
186	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.7	$ 25.6	$ 25.5	$ 25.5	$ 25.3
187	Fish Creek	Generation	**1,000 MWh**	-	-	-	-	239.3	255.3	254.7	252.8	251.5	250.2	249.7	247.7
188	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 16.2	$ 17.3	$ 17.2	$ 17.1	$ 17.0	$ 16.9	$ 16.9	$ 16.7
189	Mission Rd	Generation	**1,000 MWh**	-	-	-	-	286.1	305.2	304.5	302.1	300.6	299.1	298.4	296.1
190	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 17.9	$ 19.1	$ 19.0	$ 18.9	$ 18.8	$ 18.7	$ 18.6	$ 18.5
191	Little Trout	Generation	**1,000 MWh**	-	-	-	-	24.2	290.5	289.9	287.6	286.2	284.7	284.1	281.9
192	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ 1.6	$ 19.0	$ 19.0	$ 18.8	$ 18.7	$ 18.6	$ 18.6	$ 18.4
193	2027 Unapproved - VGP	Generation	**1,000 MWh**	-	-	-	-	-	365.1	390.4	387.4	385.5	383.6	382.7	379.7
194	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ 24.8	$ 27.2	$ 27.8	$ 28.3	$ 28.7	$ 28.6	$ 28.4
195	2028 Unapproved - VGP	Generation	**1,000 MWh**	-	-	-	-	-	-	615.4	654.5	651.2	648.0	646.5	641.5
196	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ 43.0	$ 46.8	$ 46.6	$ 46.3	$ 46.2	$ 45.9
197	2029 Unapproved - VGP	Generation	**1,000 MWh**	-	-	-	-	-	-	-	160.9	171.6	170.7	170.3	169.0
198	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.6	$ 12.5	$ 12.4	$ 12.4	$ 12.3
199	**VGP Supporting Projects - Total Generation**		**1,000 MWh**	1,144.3	1,084.1	1,315.4	1,972.1	2,794.6	5,358.1	6,616.2	7,426.9	7,415.0	7,386.0	7,375.8	7,328.3
200	**VGP Supporting Projects - Total PSCR Transfer Amount**		**$Mil**	$ 55.2	$ 52.2	$ 63.9	$ 103.4	$ 157.0	$ 318.8	$ 405.5	$ 461.0	$ 464.2	$ 464.0	$ 464.4	$ 462.5

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	VGP DTE Owned Solar														
161	Gratiot Solar	Generation	**1,000 MWh**	94.7	94.7	94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8	94.8
162	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2	$ 7.2
163	Pine River Solar	Generation	**1,000 MWh**	152.6	152.6	152.6	152.6	152.6	152.6	152.6	152.6	152.6	152.6	152.5	152.5
164	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0	$ 10.0
165	Polaris Solar	Generation	**1,000 MWh**	186.3	186.3	186.3	186.3	186.3	186.3	186.3	186.3	186.3	186.3	186.2	186.2
166	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.9
167	Sauk Solar	Generation	**1,000 MWh**	294.3	292.8	292.2	289.9	288.4	287.0	286.4	284.1	282.7	281.3	280.7	278.5
168	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 16.0	$ 15.9	$ 15.9	$ 15.8	$ 15.7	$ 15.6	$ 15.6	$ 15.5	$ 15.4	$ 15.3	$ 15.3	$ 15.2
169	Wheeler Center - Customer Requested	Generation	**1,000 MWh**	26.3	26.2	26.1	25.9	25.8	25.7	25.6	25.4	25.3	25.2	25.1	24.9
170	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 2.1	$ 2.1	$ 2.2	$ 2.2	$ 2.2	$ 2.3	$ 2.3	$ 2.4	$ 2.4	$ 2.4	$ 2.5	$ 2.5
171	Ford I - 2024 - Customer Requested - P	Generation	**1,000 MWh**	410.3	408.2	407.3	404.2	402.2	400.1	399.2	396.1	394.2	392.2	391.3	388.3
172	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 23.8	$ 23.7	$ 23.7	$ 23.5	$ 23.4	$ 23.2	$ 23.2	$ 23.0	$ 22.9	$ 22.8	$ 22.7	$ 22.6
173	Ford I - 2024 - Customer Requested - P	Generation	**1,000 MWh**	191.5	190.5	190.1	188.6	187.7	186.7	186.3	184.9	183.9	183.0	182.6	181.2
174	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 12.4	$ 12.4	$ 12.3	$ 12.2	$ 12.2	$ 12.1	$ 12.1	$ 12.0	$ 11.9	$ 11.9	$ 11.9	$ 11.8
175	Ford II - 2025 - Customer Requested - F	Generation	**1,000 MWh**	265.1	263.8	263.2	261.1	259.8	258.5	257.9	256.0	254.7	253.4	252.8	250.9
176	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 15.6	$ 15.5	$ 15.5	$ 15.4	$ 15.3	$ 15.2	$ 15.2	$ 15.1	$ 15.0	$ 14.9	$ 14.9	$ 14.8
177	Ford II - 2025 - Customer Requested - F	Generation	**1,000 MWh**	439.3	437.1	436.1	432.7	430.6	428.4	427.5	424.2	422.0	419.9	419.0	415.7
178	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 26.3	$ 26.1	$ 26.1	$ 25.9	$ 25.8	$ 25.6	$ 25.6	$ 25.4	$ 25.2	$ 25.1	$ 25.1	$ 24.9
179	2027 Project 1 - Customer Requested	Generation	**1,000 MWh**	382.3	380.4	379.5	376.6	374.7	372.8	372.0	369.1	367.3	365.4	364.6	361.8
180	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 23.7	$ 23.6	$ 23.5	$ 23.3	$ 23.2	$ 23.1	$ 23.1	$ 22.9	$ 22.8	$ 22.7	$ 22.6	$ 22.4
181	Unnamed - 2025 - Customer Requestec	Generation	**1,000 MWh**	337.7	336.0	335.3	332.7	331.0	329.4	328.6	326.1	324.5	322.8	322.1	319.6
182	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 21.2	$ 21.1	$ 21.1	$ 20.9	$ 20.8	$ 20.7	$ 20.7	$ 20.5	$ 20.4	$ 20.3	$ 20.3	$ 20.1
183	Unknown Approved - Unnamed - Custo	Generation	**1,000 MWh**	224.9	223.7	223.2	221.5	220.4	219.3	218.8	217.1	216.0	214.9	214.4	212.8
184	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 14.8	$ 14.7	$ 14.7	$ 14.5	$ 14.5	$ 14.4	$ 14.4	$ 14.3	$ 14.2	$ 14.1	$ 14.1	$ 14.0
185	2028 Project 1 - Customer Requested	Generation	**1,000 MWh**	386.7	384.8	383.9	380.9	379.0	377.1	376.3	373.4	371.5	369.7	368.8	366.0
186	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 25.1	$ 25.0	$ 25.0	$ 24.8	$ 24.6	$ 24.5	$ 24.5	$ 24.3	$ 24.1	$ 24.0	$ 24.0	$ 24.2
187	Fish Creek	Generation	**1,000 MWh**	246.5	245.3	244.7	242.8	241.6	240.4	239.9	238.0	236.8	235.6	235.1	233.3
188	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 16.7	$ 16.6	$ 16.5	$ 16.4	$ 16.3	$ 16.3	$ 16.2	$ 16.1	$ 16.0	$ 15.9	$ 15.9	$ 15.8
189	Mission Rd	Generation	**1,000 MWh**	294.7	293.2	292.5	290.3	288.8	287.4	286.7	284.5	283.1	281.7	281.0	278.8
190	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 18.4	$ 18.3	$ 18.3	$ 18.1	$ 18.0	$ 18.0	$ 17.9	$ 17.8	$ 17.7	$ 17.6	$ 17.6	$ 17.4
191	Little Trout	Generation	**1,000 MWh**	280.5	279.1	278.5	276.3	274.9	273.6	272.9	270.8	269.5	268.1	267.5	265.4
192	2021 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 18.3	$ 18.2	$ 18.2	$ 18.1	$ 18.0	$ 17.9	$ 17.8	$ 17.7	$ 17.6	$ 17.5	$ 17.5	$ 17.4
193	2027 Unapproved - VGP	Generation	**1,000 MWh**	377.8	375.9	375.1	372.2	370.3	368.5	367.6	364.8	363.0	361.2	360.3	357.6
194	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 28.2	$ 28.1	$ 28.0	$ 27.8	$ 27.7	$ 27.5	$ 27.5	$ 27.3	$ 27.1	$ 27.0	$ 26.9	$ 26.7
195	2028 Unapproved - VGP	Generation	**1,000 MWh**	638.3	635.1	633.7	628.8	625.6	622.5	621.1	616.3	613.2	610.1	608.8	604.1
196	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 45.6	$ 45.4	$ 45.3	$ 44.9	$ 44.7	$ 44.5	$ 44.4	$ 44.1	$ 43.8	$ 43.6	$ 43.5	$ 43.2
197	2029 Unapproved - VGP	Generation	**1,000 MWh**	168.2	167.3	167.0	165.7	164.8	164.0	163.7	162.4	161.6	160.8	160.4	159.2
198	2022 MPSC Staff Transfer Prices	Transfer Amount to PSCR	**$Mil**	$ 12.2	$ 12.1	$ 12.1	$ 12.0	$ 12.0	$ 11.9	$ 11.9	$ 11.8	$ 11.7	$ 11.7	$ 11.6	$ 11.6
199		**VGP Supporting Projects - Total Generation**	**1,000 MWh**	7,299.7	7,271.2	7,261.2	7,214.6	7,186.5	7,158.6	7,148.8	7,103.1	7,075.5	7,048.0	7,038.5	6,993.6
200		**VGP Supporting Projects - Total PSCR Transfer Amount**	**$Mil**	$ 461.2	$ 459.8	$ 459.3	$ 456.5	$ 454.8	$ 453.2	$ 452.7	$ 449.9	$ 448.3	$ 446.8	$ 446.3	$ 444.0

Line No.	(a)	(b)	(c)	(d) Preliminary 2022	(e) Preliminary 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033
	VGP Subscribed														
201	MIGreenPower Subscribed	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
202		Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203	VGP Subscribed	Generation	**1,000 MWh**	(1,054.4)	(1,184.5)	(1,315.4)	(1,972.1)	(2,794.6)	(5,358.1)	(6,616.2)	(7,426.9)	(7,415.0)	(7,386.0)	(7,375.8)	(7,328.3)
204		Transfer Amount to PSCR	**$Mil**	$ (52.0)	$ (59.8)	$ (63.9)	$ (103.4)	$ (157.0)	$ (318.8)	$ (405.5)	$ (461.0)	$ (464.2)	$ (464.0)	$ (464.4)	$ (462.5)
205		**Total Subscribed VGP Generation**	**1,000 MWh**	(1,054.4)	(1,184.5)	(1,315.4)	(1,972.1)	(2,794.6)	(5,358.1)	(6,616.2)	(7,426.9)	(7,415.0)	(7,386.0)	(7,375.8)	(7,328.3)
206		**Total Subscribed VGP Transfer Amount to PSCR**	**$Mil**	$ (52.0)	$ (59.8)	$ (63.9)	$ (103.4)	$ (157.0)	$ (318.8)	$ (405.5)	$ (461.0)	$ (464.2)	$ (464.0)	$ (464.4)	$ (462.5)
207		**VGP Net Subscriptions PSCR Generation**	**1,000 MWh**	89.9	(100.5)	-	-	-	-	-	-	-	-	-	-
208		**VGP Net Subscriptions PSCR Transfer Expense**	**$Mil**	$ 3.1	$ (7.7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		**Generation - PPA** (including VGP)	**1,000 MWh**	**1,663.9**	**1,491.9**	**1,739.4**	**1,759.5**	**2,211.7**	**2,979.8**	**3,687.6**	**4,387.2**	**4,942.5**	**4,851.2**	**4,550.4**	**4,157.8**
210		**Cost of Contracts**	**$Mil**	**$ 109.2**	**$ 98.5**	**$ 113.2**	**$ 114.2**	**$ 148.8**	**$ 210.0**	**$ 263.0**	**$ 313.3**	**$ 347.8**	**$ 337.2**	**$ 309.8**	**$ 285.8**
211		**Total Generation (excluding VGPs)**	**1,000 MWh**	**4,377.1**	**3,802.8**	**4,448.8**	**4,576.4**	**5,028.9**	**6,711.8**	**8,102.6**	**10,126.4**	**12,155.3**	**14,129.1**	**15,229.9**	**16,887.5**
212		**Total PSCR Transfer Expense**	**$Mil**	**$ 344.5**	**$ 309.8**	**$ 365.5**	**$ 380.6**	**$ 417.3**	**$ 539.8**	**$ 650.4**	**$ 809.6**	**$ 966.5**	**$ 1,127.0**	**$ 1,226.9**	**$ 1,277.0**

Line No.	(a)	(b)	(c)	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040	(w) 2041	(x) 2042	(y) 2043	(z) 2044	(aa) 2045
	VGP Subscribed														
201	MIGreenPower Subscribed	Generation	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
202		Transfer Amount to PSCR	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203	VGP Subscribed	Generation	**1,000 MWh**	(7,299.7)	(7,271.2)	(7,261.2)	(7,214.6)	(7,186.5)	(7,158.6)	(7,148.8)	(7,103.1)	(7,075.5)	(7,048.0)	(7,038.5)	(6,993.6)
204		Transfer Amount to PSCR	**$Mil**	$ (461.2)	$ (459.8)	$ (459.3)	$ (456.5)	$ (454.8)	$ (453.2)	$ (452.7)	$ (449.9)	$ (448.3)	$ (446.8)	$ (446.3)	$ (444.0)
205		**Total Subscribed VGP Generation**	**1,000 MWh**	(7,299.7)	(7,271.2)	(7,261.2)	(7,214.6)	(7,186.5)	(7,158.6)	(7,148.8)	(7,103.1)	(7,075.5)	(7,048.0)	(7,038.5)	(6,993.6)
206		**Total Subscribed VGP Transfer Amount to PSCR**	**$Mil**	$ (461.2)	$ (459.8)	$ (459.3)	$ (456.5)	$ (454.8)	$ (453.2)	$ (452.7)	$ (449.9)	$ (448.3)	$ (446.8)	$ (446.3)	$ (444.0)
207		**VGP Net Subscriptions PSCR Generation**	**1,000 MWh**	-	-	-	-	-	-	-	-	-	-	-	-
208		**VGP Net Subscriptions PSCR Transfer Expense**	**$Mil**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209		**Generation - PPA** (including VGP)	**1,000 MWh**	**3,588.6**	**3,506.4**	**3,500.8**	**3,476.2**	**3,461.2**	**3,446.3**	**3,440.8**	**3,416.7**	**3,402.0**	**3,387.4**	**3,382.1**	**3,358.3**
210		**Cost of Contracts**	**$Mil**	**$ 257.6**	**$ 253.2**	**$ 253.0**	**$ 251.5**	**$ 250.6**	**$ 249.8**	**$ 249.6**	**$ 248.1**	**$ 247.3**	**$ 246.5**	**$ 246.3**	**$ 244.9**
211		**Total Generation (excluding VGPs)**	**1,000 MWh**	**18,454.4**	**20,763.6**	**23,454.4**	**26,019.5**	**28,651.1**	**31,285.2**	**34,014.7**	**36,560.8**	**38,960.2**	**39,298.9**	**39,343.9**	**39,174.2**
212		**Total PSCR Transfer Expense**	**$Mil**	**$ 1,177.0**	**$ 1,282.2**	**$ 1,439.5**	**$ 1,592.0**	**$ 1,751.5**	**$ 1,913.9**	**$ 2,085.4**	**$ 2,249.0**	**$ 2,391.7**	**$ 2,411.6**	**$ 2,414.6**	**$ 2,404.4**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	)	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KIRK M. VANGILDER

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KIRK M. VANGILDER

Line No.

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

A1. My name is Kirk M. Vangilder (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 (DTE Energy), within the Regulatory Affairs organization as a Principal Financial Analyst for Revenue Requirements.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric, DTE or Company).

Q3. What is your educational background?

A3. I received a Bachelor of Arts Degree in Accounting from Michigan State University's Eli Broad College of Business in 2004 and a Master of Science Degree in Accounting from Michigan State University's Eli Broad Graduate School of Management in 2006.

Q4. Have you completed any seminars or other training courses?

A4. Yes, I have. I completed a utility finance and ratemaking course taught by Excidian, LLC. Additionally, I attended trainings hosted by Electric Utility Consultants, Inc, (EUCI) on utility cost of service and ratemaking. I also completed the ratemaking program conducted by the Institute of Public Utilities at Michigan State University.

Q5. What work experience do you have?

Line
No

A5. From 2006 to 2011, I practiced public accounting with the international accounting firm Grant Thornton LLP where I had positions of increasing responsibility. During this time, I received my Certified Public Accountant license. In October 2011, I joined DTE Energy as a Financial Auditor in the Audit Services department. In March 2013 I was promoted to Senior Financial Auditor, where I performed substantive testing and controls testing to support DTE Energy's financial statement audits and regulatory filings process. In August 2014, I accepted a position within DTE Energy's Controllers organization as a Senior Business Financial Analyst with responsibility for various accounting, budgeting, and reporting activities for DTE Gas Company, including financial and revenue requirement modeling. In 2018, I transferred to Regulatory Affairs as a Senior Rate Analyst in their Revenue Requirements group, and in 2019 I was promoted to my current position as Principal Financial Analyst.

Q6. Do you hold any certifications or are you a member of any professional organizations?

A6. I received my Certified Public Accountant license in 2008 and am currently a registered accountant within the State of Michigan.

Q7. What are your current duties and responsibilities?

A7. As a Principal Financial Analyst for Revenue Requirements within DTE Energy's Regulatory Affairs organization, I am responsible for revenue requirement studies for regulatory filings, regulatory analysis and research, and for supporting certain MPSC filings such as general rate cases.

Line
No

Q8. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A8. Yes. I have sponsored testimony in the following cases:

U-20373	DTE Electric 2020-2021 EWR Plan
U-20373-A	DTE Electric 2020-2021 Amended EWR Plan
U-20429	DTE Gas 2020-2021 EWR Plan
U-20642	DTE Gas 2019 Main Rate Case
U-20703	DTE Electric 2019 EWR Reconciliation
U-20708	DTE Gas 2019 EWR Reconciliation
U-20711	DTE Electric 2019 PLD/TRM Reconciliation
U-20836	DTE Electric 2022 General Rate Case
U-20876	DTE Electric 2022-2023 EWR Plan
U-20881	DTE Gas 2022-2023 EWR Plan
U-20940	DTE Gas 2021 General Rate Case
U-20987	DTE Electric 2020 PLD/TRM Reconciliation
U-21206	DTE Electric & DTE Gas 2021 EWR Reconciliation
U-21242	DTE Electric 2021 Demand Response Reconciliation
U-21291	DTE Gas 2024 General Rate Case
U-21297	DTE Electric 2023 General Rate Case
U-21307	DTE Electric 2021 & 2022 PLD/TRM Reconciliations
U-21313	DTE Electric & DTE Gas 2022 EWR Reconciliation
U-21403	DTE Electric 2022 Demand Response Reconciliation
U-21534	DTE Electric 2024 General Rate Case
U-21658	DTE Electric 2023 Demand Response Reconciliation

Line
No

Purpose of Testimony

Q9. What is the purpose of your testimony?

A9. The purpose of my testimony is to present the incremental cost of compliance calculation based on the information, costs, and any potential Renewable Energy Plan (REP) surcharge revenues associated with DTE Electric's 2024 Amended REP that were supplied to me and are supported in this application by DTE Electric Witnesses Bilyeu, Eddie, Kauffman, Kopinski, Meloche and Wisniewski. I am also supporting the pre-tax cost of capital that I use to calculate the return on rate base, and the calculation of interest on regulatory liabilities.

Q10. Are you sponsoring any exhibits in this proceeding?

A10. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-22	Incremental Cost of Compliance Summary
A-23	Revenue Requirement
A-24	Interest on Regulatory Liability
A-25	Pre-Tax Rate of Return and Revenue Conversion Factors
A-26	Actual and Forecast Meter Counts by Class

Q11. Were these exhibits prepared by you or under your direction?

A11. Yes, they were.

Q12. What is DTE Electric's criterion for determining which years to display on its REP Exhibits?

Line
No

A12. MCL 460.1049 requires annual REP reconciliation proceedings. Years for which the Commission has issued a final order in an REP reconciliation filing approving the actual REP costs (i.e., reconciled years) will not be included in any amended plans subsequently filed by the Company. This amended plan will carry forward the approved balances and start with the year immediately following the most recently reconciled year. The most recent approved REP reconciliation case was filed on June 27, 2022 in Case No. U-21198 for calendar year 2021. An order was issued in that case on April 24, 2023; therefore, I will only reflect the years 2022-2045 on these REP exhibits.

Q13. Is the calculation of incremental cost of compliance that you support in this proceeding performed in the same manner as it was in the Company's Commission-approved REP plan?

A13. Yes, except that for the first time, the subtractions for an Allowance for Funds Used During Construction (AFUDC), are included. Otherwise, the calculation of the incremental cost of compliance I support in this proceeding was performed in the same manner as it was in the Company's Commission-approved REP plan.

Q14. Can you describe the information displayed on Exhibit A-22, "Incremental Cost of Compliance Summary"?

A14. Exhibit A-22 displays the incremental cost of compliance calculation. The exhibit is arranged in three sections to match the language contained in MCL 460.1047 that describes the components of the incremental cost of compliance. Exhibit A-22 displays the gross sum of the costs described in MCL 460.1047(2)(a), the revenues/credits to be subtracted described in MCL 460.1047(2)(b), and carrying

costs on regulatory assets described in MCL 460.1047(3). It should be noted that several of these lines or subcomponents described within a line have zero values but are included on the exhibit for completeness and possible future use.

Q15. Can you describe in more detail the incremental costs defined in MCL 460.1047(2)(a) and (2)(b) included on Exhibit A-22?

A15. Exhibit A-22, line 2 addresses subparts (i, ii, iii, iv) of MCL 460.1047(2)(a) and consists of Capital, Operating and Maintenance (O&M), Return on Equity (ROE), Financing, Interconnect, and Ancillary service costs. Line 3 addresses subpart (v)(A) and consists of the costs of renewable energy credit (REC) purchases. Line 4 addresses subpart (v)(B) and consists of costs of contracts described under former MCL 460.1033(1) (i.e., estimated third party purchase power agreements (PPAs) charges). Line 5 addresses subpart (v)(C) and consists of VGP subscription revenue Financial Compensation Mechanism (FCM) exclusion. Line 6 consists of the payments to tax equity partnerships (presently zero). Line 7 shows the sum of lines 1 through 6, DTE Electric's 2008 PA 295, as amended by 2016 PA 342 and 2023 PA 235, REP Gross Revenue Requirement. Line 9 addresses subpart (i) of MCL 460.1047(2)(b) and consists of revenue from the sale of environmental attributes (i.e., REC sales) (presently zero). Lines 10 through 12 address subpart (iii) and consist of tax credits to promote renewable energy (i.e., production tax credits (PTC) and investment tax credits (ITCs)) as well as the related transfer discounts. Line 13 addresses subpart (iv) and consists of costs subject to recovery through the Power Supply Cost Recovery (PSCR). These costs were supplied by Witness Kopinski. Lines 14-20 address subpart (vi) and consists of additional revenue as determined by the Commission, which consists of MIGreenPower subscription

Line
No

revenue (revised Rider 17) for years 2023 and beyond and MIGreenPower (former Rider 17) and VGP (formerly Rider 19) subscription revenue in year 2022. Line 21 (which is presently zero) consists of the distributions from tax equity partnerships. Line 22 addresses subpart (vii) and consists of revenue recovered in rates for renewable energy costs included in MCL 460.1047(2)(a) (presently proposed to be zero). Line 23 is for the amortization of the Regulatory Liability associated with the TCJA and is supported by Witness Wisniewski. Lines 25 through 29 are provided by Witness Kauffman and reflect the activity associated with the Commission Order in Case No. U-21496 which provided approval for the Company to accrue AFUDC on Construction Work in Progress (CWIP) for renewable projects within the REP effective October 1, 2023. As shown in lines 25 to 29, the incremental cost of compliance is reduced by the AFUDC credits and related tax impacts. Line 31 is a subtotal of all subtractions (lines 9 through 29). Line 32 is the net of lines 7 and 31 and is the incremental cost of compliance prior to adding interest.

Q16. Can you describe the remaining lines included on Exhibit A-22?

A16. Line 33 is the interest on regulatory liabilities that I calculate on Exhibit A-24 pursuant to MCL 460.1047(2)(b)(ii) and the applicable interest rate [the average short-term borrowing rate available to the electric provider (in this instance DTE Electric) during the appropriate period] as specified in MCL 460.1047(3). Line 34 contains the carrying charges for regulatory assets that is described in MCL 460.1047(3). Line 36 shows the total incremental cost of compliance for the years 2022 through 2045.

Line
No

Q17. Can you describe the information displayed on Exhibit A-23?

A17. Exhibit A-23 titled "Revenue Requirement" includes the calculation of average net rate base and gross revenue requirements. Line 11, average net rate base, is comprised of the following components: Plant in Service, CWIP, Accumulated Depreciation Reserve, REC inventory, transmission company Accounts Receivable/(Payable), the net equity investment in Big Turtle, LLC, and Accumulated Deferred Income Taxes. Line 24, gross revenue requirement, is comprised of the following cost components: Pre-Tax Return on Net Rate Base, PPA Purchased Power, RECs consumed, O&M, Royalty Payments, Depreciation, Property Taxes, Insurance, and VGP subscription revenue FCM exclusion.

Q18. What is the source of the information you used to calculate the revenue requirement?

A18. In addition to the pre-tax return on equity that I calculated on Exhibit A-25, I relied upon information supplied by Witnesses Kauffman, Bilyeu, Wisniewski and Kopinski. Specifically, Witness Kauffman provided the Blended ROE, O&M, Royalty Payments, Depreciation, Property Taxes, Insurance, the average Plant-In-Service, CWIP, Depreciation Reserve, and transmission company Accounts Receivable/(Payable). Witness Wisniewski provided deferred taxes. Witness Bilyeu supplied the RECs consumed. He also provided renewable power expense and REC purchases and consumption expense to Witness Kauffman who in turn supplied me with the average REC inventory balances. Witness Kopinski supplied the PPA Purchased Power and VGP Sub Rev FCM Revenue Exclusion.

Line
No

Q19. What is the traditional definition of rate base used in general rate case filings in Michigan?

A19. Traditionally, in Michigan, rate base is comprised of Plant-In-Service less Depreciation Reserve plus CWIP, Working Capital, and Future Use.

Q20. How was rate base determined in this REP filing?

A20. REP rate base in this case follows the traditional definition used in general rate cases but is adjusted to reflect the impacts of accumulated deferred income taxes and prepaid taxes.

Q21. Why is REP rate base adjusted to reflect accumulated prepaid and deferred income taxes for this REP filing?

A21. Consistent with the treatment of accumulated prepaid and deferred income taxes used in DTE Electric's original Commission-approved 2008 PA 295 REP, accumulated prepaid and deferred income taxes are included as part of rate base determination because, unlike in general rate cases, they have not been included in the development of the 2008 PA 295, as amended by 2016 PA 342 and PA 235, REP's Pre-tax Rate of Return. Therefore, these income taxes must be considered as part of rate base in order to accurately determine the REP's required pre-tax return. This REP rate base treatment for taxes is required to match the pre-tax weighted average cost of permanent capital that is used to calculate the return on rate base. Absent this tax adjustment to each year's REP rate base, it would be necessary to calculate a rate of return for each year to reflect the effects of changes in zero cost capital that result from prepaid and deferred income taxes.

Line
No

Q22. Are there any costs that, due to Commission Orders, the Company is required to address outside of the REP?

A22. Yes. The June 2, 2009 Order in MPSC Case No. U-15806 indicated uncollectible expenses reflected in the original proposed 2008 PA 295 REP would be addressed in the Company's next general rate case. Therefore, uncollectible expenses are excluded from this Amended REP. Page 22 of the June 2, 2009 Order in MPSC Case No. U-15806 indicated that Net Equity Costs Due to Imputed Debt would be considered at the time of PPA approval. In subsequent Commission Orders[1] approving PPAs the Commission indicated that requests for imputed debt-related cost recovery would be handled in general rate cases. Therefore, Net Equity Costs Due to Imputed Debt are excluded from this Amended REP.

Q23. What information is reflected on Exhibit A-24?

A23. Exhibit A-24 titled "Interest on Regulatory Liability" shows the calculation of the average regulatory liability balance and the interest on that balance. Line 1 contains the REP Surcharge (a/k/a Revenue Recovery Mechanism surcharge) revenue, which is only a non-zero value when the projected ending balance on line 4 is expected to be a in regulatory asset position. Since DTE Electric is not projecting a regulatory asset position until 2029, the Company will continue to monitor and if needed, propose a surcharge mechanism in its next Amended REP as discussed further by Witness Bilyeu. Line 2 contains the incremental cost of compliance from Exhibit A-22, line 36. Line 3 contains the regulatory liability increase or (decrease) for each year and is the result of subtracting the incremental cost of compliance in line 2 from the REP surcharge revenues in line 1. Line 4 is the regulatory liability

[1] September 14, 2010 Commission Order in Case No. U-15806, page 6 and October 31, 2012 Commission Order in Case No. U-16582, page 7.

Line No

or asset ending balance for each year and is the sum of the prior year ending balance and the current year change from line 3. Line 5 is the average regulatory liability or asset. Line 5 is multiplied by the average short term interest rates on line 6 provided by DTE Energy's Treasury department to calculate the interest on the average regulatory liability (line 7). In the event that line 5 yields a regulatory asset balance for a year within the plan, a carry charge is calculated using the same methodology as any interest on the average regulatory liability.

In accordance with MCL 460.1047(2)(b)(ii), the interest on the regulatory liability is subtracted from the cost of compliance and is displayed on Exhibit A-22, line 33. In accordance with MCL 460.1047(3), the carrying charge on any regulatory asset is added to the cost of compliance and is displayed on Exhibit A-22, line 34.

Q24. Did the Commission provide guidance regarding the weighted average cost of capital that should be used to calculate the "Return On" Rate Base?

A24. Yes. In Attachment A to the December 4, 2008 Temporary Order in Case No. U-15800, the Commission stated "Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (MCL 460.1047(1))." In Exhibit A to the August 23, 2017 Order in Case No. U-18409, the Commission includes the same directive. However, as required by the Commission in its July 18, 2019 Order in Case No. U-18232, the Company's current approved (U-20561) ROE is utilized for certain assets, which results in "blended ROE," as more fully explained by Witness Kauffman.

Line
No

Q25. What pre-tax rate of return have you used to calculate the return on rate base for the years 2022 and 2023?

A25. I used the annual pre-tax rate of return from two REP reconciliation filings: the as-filed amount from Case No. U-21353 (2022) and the as-filed amount from Case No. U-21550 (2023).

Q26. What pre-tax rate of return have you used for years 2024 through 2045?

A26. I used the pre-tax rate of return shown on line 9 of Exhibit A-25, Schedule B1 titled "Pre-Tax Rate of Return". This pre-tax rate of return includes the blended rate of return on equity calculated by Witness Kauffman on his Exhibit A-9, and the debt to equity ratio that was authorized at the time DTE Electric's Original REP was approved and is based on the December 23, 2008 order in Case No. U-15244.[2] The long-term debt component of the rate of return is calculated using the actual cost of debt for 2022 and 2023 that was supplied to me by the DTE Treasury department For the years 2024-2045, I used the debt approved in DTE Electric's most recent general rate case, Case No. U-21297. The revenue conversion factors are calculated in columns (a) and (b), Exhibit A-25, Schedule B2, and reflect Michigan Corporate Income tax, municipal tax rates and Federal Income tax rates.

Q27. What is the equity revenue multiplier shown on Exhibit A-25, Schedule B2?

A27. The Revenue Conversion Factor, also known as the Revenue Multiplier, is a multiplication factor that converts a utility's after-tax income into pre-tax revenue. For the REP, the overall revenue multiplier derived on Exhibit A-25 is used to convert the after-tax return on equity component to its pre-tax equivalent. Revenue

[2] The December 23, 2008 Order in MPSC Case No. U-15244 at page 15 approves a long-term debt rate of 5.76% and at page 21 approves a rate of return on equity of 11.0%.

Line No

collected to cover a Utility's equity return is subject to Michigan Corporate Income Tax, Municipal Income Tax, and Federal Income Tax.

Q28. What information is presented on Exhibit A-26 titled "Actual and Forecast Meter Counts by Class"?

A28. Exhibit A-26 provides the Company's actual (2022-2023) and forecast (2024 – 2045) retail customer meter counts by class, which are required pursuant to the Commission's filing requirements established in the August 23, 2017 Order issued in Case No. U-18409 (see Exhibit A pages 2 and 8 attached to Order).

Q29. How were the forecasted meter counts on A-26 determined?

A29. The starting point for determining the number of meters was a current forecast of the number of bundled customers provided on Exhibit A-32, sponsored by Company Witness Meloche. To translate the bundled customer counts to meter counts, I multiplied the customer counts by the average number of meters per customer for each class. This is performed in the same manner as it was in the Company's Commission-approved REP plan filed March 9, 2023 (Case No. U-21361) and approved in the Commission's May 18, 2023 order. The Company utilized the following meter to customer ratios:

Residential = 1.0 meter per customer

Commercial Secondary = 1.0 meters per customer

Commercial & Industrial Primary = 1.20 meters per customer.

Q30. Will there be ongoing costs of compliance after the 20-year REP period ends?

Line
No

A30. Most likely there will be ongoing costs of compliance after the 20-year REP period ends. As shown on Exhibit A-23 the Company projects that it will continue to have an ongoing revenue requirement associated with its REP at the end of the 20-year REP period. Unless these costs are completely offset by the subtractions described in MCL 460.1047(2)(b), there will be ongoing costs of compliance after the 20-year REP period ends.

Q31. Does this complete your direct testimony?

A31. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

OF

KIRK M. VANGILDER

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Incremental Cost of Compliance Summary
($ Millions)

Case No.: U-21662
Exhibit: A-22
Witness: K. Vangilder
Page: 1 of 2

Line No.	MCL 460.1047	Description	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	(a)	(b)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	(2)(a)	**Sum of Costs:**												
2	(i,ii,iii,iv)	Capital, O&M, ROE, Financing, Interconnect & Ancillary	373.4	404.5	505.6	677.5	934.8	1,251.8	1,446.8	1,594.4	1,732.0	1,895.7	2,030.1	2,215.1
3	(v)(A)	Expected RECs to be Consumed	2.0	1.3	4.1	2.6	2.9	3.3	3.5	3.9	8.6	9.6	10.4	11.1
4	(v)(B)	Costs of Contracts under Sec 33(1) - Estimated PPA Charges	108.4	98.2	113.2	114.2	148.8	210.0	263.0	313.3	347.8	337.2	309.8	285.8
5	(v)(C)	VGP Subscription Revenue FCM Revenue Exclusion	-	-	-	-	-	1.0	2.8	3.3	3.3	3.3	3.3	3.3
6		Total Payment to Tax Equity Partnership(s)	-	-	-	-	-	-	-	-	-	-	-	-
7		**Subtotal of Costs (Gross Revenue Requirement)**	483.7	504.0	622.9	794.2	1,086.5	1,466.1	1,716.1	1,914.9	2,091.8	2,245.9	2,353.6	2,515.3
8	(2)(b)	**Subtractions from the Sum of Costs:**												
9	(i)	Revenue from the Sale of Environmental Attributes - REC Sales	-	-	-	-	-	-	-	-	-	-	-	-
10	(iii)	Tax Credits to Promote Renewable Energy - PTC	111.4	107.2	111.0	121.3	135.8	236.7	334.4	451.5	535.9	594.7	633.8	722.0
11	(iii)	Tax Credits to Promote Renewable Energy - Transfer Discount		-	(10.9)	(6.1)	(6.8)	(11.8)	(16.7)	(22.6)	(26.8)	(29.7)	(31.7)	(36.1)
12	(iii)	Tax Benefit of Solar Grants / Investment Tax Credit	0.0	0.7	2.5	144.7	185.3	114.7	2.5	2.5	2.5	2.5	2.5	2.5
13	(iv)	Cost Recovered under the PSCR (Transfer Expense)	328.7	309.8	365.5	380.6	417.3	539.8	650.4	809.6	966.5	1,127.0	1,226.9	1,277.0
14	(vi)	VGP Subscription Revenue FCM Revenue	-	-	-	-	-	1.0	2.8	3.3	3.3	3.3	3.3	3.3
15	(vi)	VGP Subscription Revenue (Rider 19)	42.9	-	-	-	-	-	-	-	-	-	-	-
16	(vi)	VGP Subscription Credit (Rider 19)	(61.7)	-	-	-	-	-	-	-	-	-	-	-
17	(vi)	VGP Subscription Credit (PSCR reimbursement) (Rider 19)	61.7	-	-	-	-	-	-	-	-	-	-	-
18	(vi)	MiGreenPower Subscription Revenue (Rider 17)	7.5	57.4	65.0	105.5	159.4	310.9	375.1	420.6	419.7	418.1	417.5	414.8
19	(vi)	MiGreenPower Subscription Credit (Rider 17)	(5.6)	(42.6)	(60.1)	(97.1)	(147.9)	(305.5)	(420.3)	(480.7)	(455.5)	(445.6)	(425.8)	(432.1)
20	(vi)	MiGreenPower Subscription Credit (PSCR reimbursement) (Rider 17)	5.6	42.6	60.1	97.1	147.9	305.5	420.3	480.7	455.5	445.6	425.8	432.1
21		Total Cash Distribution from Tax Equity Partnership(s)	-	-	-	-	-	-	-	-	-	-	-	-
22	(vii)	Revenues Recovered in Rates for Renewable Energy Costs Included in 2(a)	-	-	-	-	-	-	-	-	-	-	-	-
23		Tax Cuts and Jobs Act of 2017 - Regulatory Liability Amortization	3.8	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.3	4.8
24														
25		AFUDC Equity (After tax)		6.1	53.9	95.0	146.1	107.5	105.1	88.7	95.4	85.0	103.0	109.3
26		AFUDC Debt (After tax)		2.4	23.2	40.9	62.8	46.3	45.2	38.2	41.1	36.6	44.3	47.0
27		AFUDC Equity Tax Gross Up		2.1	18.8	33.1	50.9	37.5	36.6	30.9	33.3	29.6	35.9	38.1
28		AFUDC Return Adjustment		0.1	5.3	9.4	14.4	10.6	10.4	8.8	9.4	8.4	10.2	10.8
29		AFUDC Equity Tax Regulatory Asset Amortization		-	(0.1)	(0.6)	(1.8)	(3.8)	(6.0)	(7.7)	(9.4)	(10.9)	(12.4)	(14.0)
30														
31		**Subtotal of Subtractions**	494.4	489.1	637.4	927.1	1,166.8	1,392.6	1,543.1	1,826.9	2,074.2	2,267.8	2,436.5	2,579.6
32		**Subtotal - Prior to Interest on Regulatory Liabilities**	(10.6)	14.8	(14.6)	(132.9)	(80.3)	73.5	173.0	87.9	17.6	(21.9)	(82.9)	(64.3)
33	(2)(b)(ii)	Interest on Regulatory Liabilities @ Short Term Interest Rate	0.3	0.7	0.7	4.0	8.1	8.6	3.9	0.2	0.0	0.5	2.6	5.7
34	(3)	Carrying Charges for Regulatory Assets @ Short Term Interest Rate	-	-	-	-	-	-	-	-	-	-	-	-
35														
36		**Total Incremental Cost of Compliance**	(11.0)	14.1	(15.3)	(136.9)	(88.4)	64.9	169.1	87.7	17.6	(22.4)	(85.5)	(70.0)

Line No.		
		Sum of Costs:
2	Capital, O&M, ROE, Financing, Interconnect & Ancillary	Exh. A-23, line 24 minus lines 15, 16, & 23
3	Expected RECs to be Consumed	Exh. A-23, line 16
4	Costs of Contracts under Sec 33(1) - Estimated PPA Charges	Exh. A-23, line 15
5	VGP Subscription Revenue FCM Revenue Exclusion	Exh. A-23, line 23
6	Total Payment to Tax Equity Partnership(s)	WP-15
8	**Subtractions from the Sum of Costs:**	
9	Revenue from the Sale of Environmental Attributes - REC Sales	none
10	Tax Credits to Promote Renewable Energy - PTC	Exh. A-8, line 15
11	Tax Credits to Promote Renewable Energy - Transfer Adjustment	Exh. A-8, line 20
12	Tax Benefit of Solar Grants / Investment Tax Credit	WP-18, line 38
13	Cost Recovered under the PSCR (Transfer Expense)	Exh. A-21, line 152
14	VGP Subscription Revenue FCM Revenue	Exh. A-23, line 23
15-20	Additional Revenue as Determined by the Commission	WP-6
21	Total Cash Distribution from Tax Equity Partnership(s)	WP-15, line 54
22	Revenues Recovered in Rates for Renewable Energy Costs Included in 2(a)	none
23	Tax Cuts and Jobs Act of 2017 Regulatory Liability Amortization	WP-16
25	AFUDC Equity (After tax)	Exh. A-6, line 21
26	AFUDC Debt (After tax)	Exh. A-6, line 22
27	AFUDC Return Adjustment	Sum lines 25 thru 26 times Regulated ROR on Exh. A-25 Sch. B3
28	AFUDC Tax Credit	Exh. A-6, line 23
29	AFUDC Tax Regulatory Asset Amortization	Exh. A-6, line 24
31	Subtotal of Subtractions	Sum lines 9 thru 30
32	**Subtotal - Prior to Interest on Regulatory Liabilities**	Line 8 minus line 31
33	Interest on Regulatory Liabilities @ Short Term Interest Rate	Exh. A-24, line 7
34	Carrying Charges for Regulatory Assets @ Short Term Interest Rate	Exh. A-24, line 8
36	**Total Incremental Cost of Compliance**	line 33 minus line 34 plus line 35

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Incremental Cost of Compliance Summary
($ Millions)

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Witness: K. Vangilder
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Line No.	MCL 460.1047	Description	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
	(a)	(b)	(p)	(q)	(r)	(s)	(t)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)
1	(2)(a)	**Sum of Costs:**												
2	(i,ii,iii,iv)	Capital, O&M, ROE, Financing, Interconnect & Ancillary	2,398.9	2,582.9	2,760.4	2,931.3	3,103.4	3,269.2	3,421.4	3,519.6	3,538.0	3,414.9	3,307.0	3,204.1
3	(v)(A)	Expected RECs to be Consumed	11.8	13.6	14.6	15.7	16.7	17.7	18.7	19.8	20.8	21.8	22.8	23.8
4	(v)(B)	Costs of Contracts under Sec 33(1) - Estimated PPA Charges	257.6	253.2	253.0	251.5	250.6	249.8	249.6	248.1	247.3	246.5	246.3	244.9
5	(v)(C)	VGP Subscription Revenue FCM Revenue Exclusion	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1
6		Total Payment to Tax Equity Partnership(s)	-	-	-	-	-	-	-	-	-	-	-	-
7		**Subtotal of Costs (Gross Revenue Requirement)**	2,671.6	2,853.0	3,031.3	3,201.7	3,373.9	3,539.8	3,692.9	3,790.7	3,809.2	3,686.2	3,579.2	3,475.9
8	(2)(b)	**Subtractions from the Sum of Costs:**												
9	(i)	Revenue from the Sale of Environmental Attributes - REC Sales	-	-	-	-	-	-	-	-	-	-	-	-
10	(iii)	Tax Credits to Promote Renewable Energy - PTC	788.9	947.3	1,057.7	1,050.6	1,060.7	1,042.9	1,182.6	1,210.1	1,267.4	1,181.3	1,149.5	1,063.7
11	(iii)	Tax Credits to Promote Renewable Energy - Transfer Discount	(39.4)	(47.4)	(52.9)	(52.5)	(53.0)	(52.1)	(59.1)	(60.5)	(63.4)	(59.1)	(57.5)	(53.2)
12	(iii)	Tax Benefit of Solar Grants / Investment Tax Credit	2.5	2.5	2.4	2.3	2.0	1.7	-	-	-	-	-	-
13	(iv)	Cost Recovered under the PSCR (Transfer Expense)	1,177.0	1,282.2	1,439.5	1,592.0	1,751.5	1,913.9	2,085.4	2,249.0	2,391.7	2,411.6	2,414.6	2,404.4
14	(vi)	VGP Subscription Revenue FCM Revenue	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1
15	(vi)	VGP Subscription Revenue (Rider 19)	-	-	-	-	-	-	-	-	-	-	-	-
16	(vi)	VGP Subscription Credit (Rider 19)	-	-	-	-	-	-	-	-	-	-	-	-
17	(vi)	VGP Subscription Credit (PSCR reimbursement) (Rider 19)	-	-	-	-	-	-	-	-	-	-	-	-
18	(vi)	MiGreenPower Subscription Revenue (Rider 17)	413.1	411.5	410.9	408.3	406.7	405.1	404.5	401.9	400.3	398.7	398.2	395.6
19	(vi)	MiGreenPower Subscription Credit (Rider 17)	(427.8)	(435.7)	(414.2)	(416.7)	(417.2)	(419.3)	(431.3)	(388.6)	(387.3)	(399.1)	(418.0)	(417.3)
20	(vi)	MiGreenPower Subscription Credit (PSCR reimbursement) (Rider 17)	427.8	435.7	414.2	416.7	417.2	419.3	431.3	388.6	387.3	399.1	418.0	417.3
21		Total Cash Distribution from Tax Equity Partnership(s)	-	-	-	-	-	-	-	-	-	-	-	-
22	(vii)	Revenues Recovered in Rates for Renewable Energy Costs Included in 2(a)	-	-	-	-	-	-	-	-	-	-	-	-
23		Tax Cuts and Jobs Act of 2017 - Regulatory Liability Amortization	5.8	6.0	6.0	6.1	6.1	6.1	6.1	6.1	5.5	5.5	5.5	0.2
24														
25		AFUDC Equity (After tax)	114.9	117.2	118.4	119.7	120.9	120.3	113.3	78.4	13.3	-	-	-
26		AFUDC Debt (After tax)	49.4	50.4	50.9	51.5	52.0	51.8	48.7	33.7	5.7	-	-	-
27		AFUDC Return Adjustment	11.4	11.6	11.7	11.8	11.9	11.9	11.2	7.7	1.3	-	-	-
28		AFUDC Equity Tax Gross Up	40.1	40.8	41.3	41.7	42.1	41.9	39.5	27.3	4.6	-	-	-
29		AFUDC Equity Tax Regulatory Asset Amortization	(15.8)	(17.7)	(19.6)	(21.6)	(23.6)	(25.6)	(27.6)	(29.6)	(31.2)	(32.0)	(32.1)	(32.1)
30														
31		**Subtotal of Subtractions**	2,551.1	2,807.6	3,069.5	3,213.0	3,380.5	3,521.0	3,807.7	3,927.3	3,998.5	3,909.2	3,881.3	3,781.8
32		**Subtotal - Prior to Interest on Regulatory Liabilities**	120.5	45.3	(38.2)	(11.3)	(6.6)	18.8	(114.8)	(136.6)	(189.3)	(222.9)	(302.1)	(305.9)
33	(2)(b)(ii)	Interest on Regulatory Liabilities @ Short Term Interest Rate	4.8	1.6	1.5	2.6	3.1	3.0	5.0	10.4	17.5	26.6	38.4	52.4
34	(3)	Carrying Charges for Regulatory Assets @ Short Term Interest Rate	-	-	-	-	-	-	-	-	-	-	-	-
35														
36		**Total Incremental Cost of Compliance**	115.6	43.7	(39.7)	(13.9)	(9.7)	15.8	(119.8)	(147.0)	(206.7)	(249.5)	(340.5)	(358.2)

Line No.		
		Sum of Costs:
2	Capital, O&M, ROE, Financing, Interconnect & Ancillary	Exh. A-23, line 24 minus lines 15, 16, & 23
3	Expected RECs to be Consumed	Exh. A-23, line 16
4	Costs of Contracts under Sec 33(1) - Estimated PPA Charges	Exh. A-23, line 15
5	VGP Subscription Revenue FCM Revenue Exclusion	Exh. A-23, line 23
6	Total Payment to Tax Equity Partnership(s)	WP-15
8	**Subtractions from the Sum of Costs:**	
9	Revenue from the Sale of Environmental Attributes - REC Sales	none
10	Tax Credits to Promote Renewable Energy - PTC	Exh. A-8, line 15
11	Tax Credits to Promote Renewable Energy - Transfer Adjustment	Exh. A-8, line 20
12	Tax Benefit of Solar Grants / Investment Tax Credit	WP-18, line 38
13	Cost Recovered under the PSCR (Transfer Expense)	Exh. A-21, line 152
14	VGP Subscription Revenue FCM Revenue	Exh. A-23, line 23
15-20	Additional Revenue as Determined by the Commission	WP-6
21	Total Cash Distribution from Tax Equity Partnership(s)	WP-15, line 54
22	Revenues Recovered in Rates for Renewable Energy Costs Included in 2(a)	none
23	Tax Cuts and Jobs Act of 2017 Regulatory Liability Amortization	WP-16
25	AFUDC Equity (After tax)	Exh. A-6, line 21
26	AFUDC Debt (After tax)	Exh. A-6, line 22
27	AFUDC Return Adjustment	Sum lines 25 thru 26 times Regulated ROR on Exh. A-25 Sch. B3
28	AFUDC Tax Credit	Exh. A-6, line 23
29	AFUDC Tax Regulatory Asset Amortization	Exh. A-6, line 24
31	Subtotal of Subtractions	Sum lines 9 thru 30
32	**Subtotal - Prior to Interest on Regulatory Liabilities**	Line 8 minus line 31
33	Interest on Regulatory Liabilities @ Short Term Interest Rate	Exh. A-24, line 7
34	Carrying Charges for Regulatory Assets @ Short Term Interest Rate	Exh. A-24, line 8
36	**Total Incremental Cost of Compliance**	line 33 minus line 34 plus line 35

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Revenue Requirement
($Millions)

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Exhibit: A-23
Witness: K. Vangilder
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Line No.	(a) Description	(b) Source	(c) 2022	(d) 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027	(i) 2028	(j) 2029	(k) 2030	(l) 2031	(m) 2032	(n) 2033
1	**Revenue Requirement Development**													
2	**Average Rate Base**													
3	Plant In-Service	Exh. A-7, line 5	2,456.4	2,781.5	2,850.3	3,209.5	4,242.1	6,466.5	8,845.9	10,624.1	12,221.2	13,810.2	15,295.5	16,775.7
4	Construction Work in Progress	Exh. A-7, line 17	405.3	450.8	1,265.2	2,573.9	3,729.5	3,495.7	2,788.8	2,603.6	2,539.6	2,461.2	2,638.8	2,962.0
5	Accumulated Depreciation Reserve	Exh. A-7, line 10	428.6	528.9	622.8	748.7	923.8	1,205.3	1,599.2	2,075.3	2,625.0	3,246.8	3,935.0	4,689.2
6	Net Plant	line 3 + line 4 - line 5	2,433.1	2,703.4	3,492.7	5,034.7	7,047.8	8,756.9	10,035.5	11,152.4	12,135.9	13,024.6	13,999.2	15,048.4
7	REC Inventory	Exh. A-7, line 22	1.7	1.3	0.7	-	-	-	-	-	-	-	-	-
8	ITC Holdings Corp. A/R / Vendor (A/P)	Exh. A-7, line 28	4.3	7.2	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.5	2.0	4.5	8.0
9	Net Equity Investment in Big Turtle Interconnect	Exh. A-7, line 34		1.2	1.6	1.5	1.3	1.2	1.1	1.0	0.8	0.7	0.6	0.5
10	Accumulated Deferred Income Taxes	Exh. A-27, line 40	(99.0)	(53.5)	(97.6)	(178.7)	(248.6)	(413.5)	(708.7)	(1,067.4)	(1,376.1)	(1,614.7)	(1,813.3)	(1,965.6)
11	Net Rate Base (Average)	Sum lines 6 thru 10	2,340.0	2,658.4	3,395.8	4,856.0	6,799.2	8,343.4	9,326.8	10,085.0	10,760.2	11,411.9	12,190.3	13,090.8
12	Pre-Tax Rate of Return	Exh. A-25, Sch. B3, line 9	8.94%	8.93%	8.89%	8.78%	8.72%	8.69%	8.68%	8.67%	8.66%	8.65%	8.65%	8.64%
13	**Revenue Requirements**													
14	Pre-Tax Return on Net Rate Base	(line 11 X 12)	207.2	235.5	301.9	426.6	593.1	725.4	809.5	874.2	931.8	987.5	1,054.1	1,131.2
15	PPA Purchased Power	Exh. A-21, line 150	108.4	98.2	113.2	114.2	148.8	210.0	263.0	313.3	347.8	337.2	309.8	285.8
16	RECs Consumed	Exh. A-4, line 12 (pgs 4-6)	2.0	1.3	4.1	2.6	2.9	3.3	3.5	3.9	8.6	9.6	10.4	11.1
17	Operation & Maintenance	Exh. A-6, line 14 + 15+ 18	34.3	28.2	48.0	52.3	59.8	71.7	81.5	91.0	97.1	105.7	111.2	119.7
18	Royalty Payments	Exh. A-6, line 13	16.4	15.1	18.6	20.5	24.1	29.9	34.1	38.0	41.3	47.1	51.1	57.1
19	Depreciation	Exh. A-6, line 19	92.4	99.3	109.6	142.2	208.0	355.0	432.9	519.4	579.9	663.8	712.6	795.7
20	Property Taxes	Exh. A-6, line 17	21.6	24.5	25.7	33.9	47.1	65.7	83.0	65.0	73.9	82.7	91.2	100.5
21	Insurance	Exh. A-6, line 16	1.6	1.9	1.8	2.1	2.7	4.2	5.7	6.9	7.9	8.9	9.9	10.9
22	Other	WP-15	(0.0)	0.1	-	-	-	-	-	-	-	-	-	-
23	VGP Sub Rev FCM Revenue Exclusion	Exh. A-21, WP-9	-	-	-	-	-	1.0	2.8	3.3	3.3	3.3	3.3	3.3
24	Gross Revenue Requirements	(Lines 13 thru 21)	483.7	504.0	622.9	794.2	1,086.5	1,466.1	1,716.1	1,914.9	2,091.8	2,245.9	2,353.6	2,515.3
			483.7	504.0										

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Revenue Requirement
($Millions)

Case No.: U-21662
Exhibit: A-23
Witness: K. Vangilder
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	(a)	(b)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
Line No.	**Description**	**Source**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
1	**Revenue Requirement Development**													
2	**Average Rate Base**													
3	Plant In-Service	Exh. A-7, line 5	18,579.7	20,426.2	22,362.7	24,320.7	26,300.2	28,301.3	30,323.9	32,368.0	34,352.7	35,328.8	35,366.6	35,405.3
4	Construction Work in Progress	Exh. A-7, line 17	3,054.9	3,152.3	3,186.6	3,221.0	3,252.9	3,248.3	3,102.3	2,347.5	859.7	0.0	0.0	0.0
5	Accumulated Depreciation Reserve	Exh. A-7, line 10	5,524.9	6,436.0	7,418.5	8,471.1	9,594.8	10,792.8	12,065.8	13,414.6	14,839.7	16,297.0	17,748.8	19,200.6
6	Net Plant	line 3 + line 4 - line 5	16,109.7	17,142.4	18,130.8	19,070.6	19,958.3	20,756.8	21,360.4	21,300.9	20,372.7	19,031.8	17,617.9	16,204.8
7	REC Inventory	Exh. A-7, line 22	-	-	-	-	-	-	-	-	-	-	-	-
8	ITC Holdings Corp. A/R / Vendor (A/P)	Exh. A-7, line 28	12.5	18.0	24.5	32.0	40.5	50.0	60.5	72.0	84.5	98.0	112.5	128.0
9	Net Equity Investment in Big Turtle Interconnect	Exh. A-7, line 34	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	Accumulated Deferred Income Taxes	Exh. A-27, line 40	(2,121.6)	(2,294.9)	(2,451.2)	(2,601.9)	(2,758.0)	(2,914.1)	(3,048.3)	(3,154.5)	(3,242.3)	(3,272.6)	(3,176.9)	(2,959.2)
11	Net Rate Base (Average)	Sum lines 6 thru 10	14,000.6	14,865.5	15,704.1	16,500.6	17,240.8	17,892.6	18,372.5	18,218.4	17,214.8	15,857.2	14,553.4	13,373.5
12	Pre-Tax Rate of Return	Exh. A-25, Sch. B3, line 9	8.64%	8.63%	8.63%	8.62%	8.62%	8.62%	8.62%	8.61%	8.61%	8.61%	8.61%	8.61%
13	**Revenue Requirements**													
14	Pre-Tax Return on Net Rate Base	(line 11 X 12)	1,209.0	1,283.0	1,354.8	1,422.9	1,486.3	1,542.0	1,582.9	1,569.3	1,482.6	1,365.5	1,253.0	1,151.3
15	PPA Purchased Power	Exh. A-21, line 150	257.6	253.2	253.0	251.5	250.6	249.8	249.6	248.1	247.3	246.5	246.3	244.9
16	RECs Consumed	Exh. A-4, line 12 (pgs 4-6)	11.8	13.6	14.6	15.7	16.7	17.7	18.7	19.8	20.8	21.8	22.8	23.8
17	Operation & Maintenance	Exh. A-6, line 14 + 15+ 18	128.3	143.6	155.0	166.5	177.9	189.3	200.8	212.2	221.9	222.0	222.2	222.2
18	Royalty Payments	Exh. A-6, line 13	63.1	75.2	85.3	95.8	106.7	118.0	129.8	142.0	151.7	153.9	156.2	156.2
19	Depreciation	Exh. A-6, line 19	875.7	946.5	1,018.4	1,086.8	1,160.6	1,235.3	1,310.7	1,386.9	1,463.4	1,451.1	1,452.4	1,451.1
20	Property Taxes	Exh. A-6, line 17	110.7	121.4	132.4	143.5	154.8	166.2	177.6	188.3	196.2	199.4	200.2	200.4
21	Insurance	Exh. A-6, line 16	12.0	13.2	14.5	15.8	17.0	18.3	19.6	21.0	22.3	22.9	22.9	22.9
22	Other	WP-15	-	-	-	-	-	-	-	-	-	-	-	-
23	VGP Sub Rev FCM Revenue Exclusion	Exh. A-21, WP-9	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.1	3.1	3.1	3.1	3.1
24	Gross Revenue Requirements	(Lines 13 thru 21)	2,671.6	2,853.0	3,031.3	3,201.7	3,373.9	3,539.8	3,692.9	3,790.7	3,809.2	3,686.2	3,579.2	3,475.9

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Interest On Regulatory Liability
($Millions)

Case No.: U-21662
Exhibit: A-24
Witness: K. Vangilder
Page: 1 of 2

Line No.	(a) Description	(b) Source	(c) 2022	(d) 2023	(e) 2024	(f) 2025	(g) 2026	(h) 2027	(i) 2028	(j) 2029	(k) 2030	(l) 2031	(m) 2032	(n) 2033
1	Surcharge Revenue	(1)	-	-	-	-	-	-	-	75.5	17.6	-	-	-
2	Incremental Cost of Compliance	Exh. A-22, line 36	(11.0)	14.1	(15.3)	(136.9)	(88.4)	64.9	169.1	87.7	17.6	(22.4)	(85.5)	(70.0)
3	Regulatory Liability - Increase / (Decrease)	line 1 - line 2	11.0	(14.1)	15.3	136.9	88.4	(64.9)	(169.1)	(12.2)	(0.0)	22.4	85.5	70.0
4	Regulatory Liability/(Asset) Ending Balance	Prior Yr End + Cur. Yr Change	19.8	5.7	21.0	157.9	246.3	181.4	12.3	0.1	0.1	22.5	108.0	178.0
5	Average Regulatory Liability/(Asset)	[Prior Yr End + Cur. Yr End]/2	14.3	12.7	13.3	89.4	202.1	213.8	96.8	6.2	0.1	11.3	65.2	143.0
6	Short Term Interest Rate (2)	Treasury	1.93%	5.17%	5.36%	4.50%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
7	Interest on Avg Reg Liability	line 5 x line 6	0.3	0.7	0.7	4.0	8.1	8.6	3.9	0.2	0.0	0.5	2.6	5.7
8	Carrying Charges for Avg Reg Asset	line 5 x line 6	-	-	-	-	-	-	-	-	-	-	-	-

(1) Surcharges are expected to offset any Regulatory Asset and are discussed in testimony by Company Witness Bilyeu
(2) Provided by DTE Treasury Department

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Interest On Regulatory Liability
($Millions)

Case No.: U-21662
Exhibit: A-24
Witness: K. Vangilder
Page: 2 of 2

Line No.	(a) Description	(b) Source	(o) 2034	(p) 2035	(q) 2036	(r) 2037	(s) 2038	(t) 2039	(u) 2040	(v) 2041	(w) 2042	(x) 2043	(y) 2044	(z) 2045
1	Surcharge Revenue	(1)	-	-	-	-	-	-	-	-	-	-	-	-
2	Incremental Cost of Compliance	Exh. A-22, line 36	115.6	43.7	(39.7)	(13.9)	(9.7)	15.8	(119.8)	(147.0)	(206.7)	(249.5)	(340.5)	(358.2)
3	Regulatory Liability - Increase / (Decrease)	line 1 - line 2	(115.6)	(43.7)	39.7	13.9	9.7	(15.8)	119.8	147.0	206.7	249.5	340.5	358.2
4	Regulatory Liability/(Asset) Ending Balance	Prior Yr End + Cur. Yr Change	62.3	18.6	58.3	72.3	82.0	66.2	186.0	333.0	539.7	789.2	1,129.7	1,487.9
5	Average Regulatory Liability/(Asset)	[Prior Yr End + Cur. Yr End]/2	120.1	40.5	38.5	65.3	77.1	74.1	126.1	259.5	436.4	664.5	959.5	1,308.8
6	Short Term Interest Rate (2)	Treasury	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
7	Interest on Avg Reg Liability	line 5 x line 6	4.8	1.6	1.5	2.6	3.1	3.0	5.0	10.4	17.5	26.6	38.4	52.4
8	Carrying Charges for Avg Reg Asset	line 5 x line 6	-	-	-	-	-	-	-	-	-	-	-	-

(1) Surcharges are expected to offset any Regulatory Asset and are discussed in testimony by Company Witness Bilyeu
(2) Provided by DTE Treasury Department

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Pre-tax Rate of Return
Based on ROE and Debt to Equity ratios
Authorized in Case No. U-15244
Debt Cost Per U-21297/ ROE Weighted

Case No.: U-21662
Exhibit: A-25 Sch. B1
Witness: K. Vangilder
Page: 1 of 2

Line No.	(a) Description	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033
1	Debt Ratio	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%
2	Debt Cost	3.79%	3.92%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
3	Revenue Conversion	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4	Debt Component	1.94%	2.01%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%
5	Equity Ratio	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%
6	Equity Cost (1)	10.61%	10.51%	10.35%	10.19%	10.09%	10.05%	10.03%	10.01%	10.00%	9.99%	9.98%	9.97%
7	Revenue Conversion	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964
8	Equity Component	6.98%	6.92%	6.81%	6.71%	6.65%	6.62%	6.60%	6.59%	6.58%	6.58%	6.57%	6.56%
9	Pre-Tax Cost of Capital	8.93%	8.93%	8.89%	8.78%	8.72%	8.69%	8.68%	8.67%	8.66%	8.65%	8.65%	8.64%
10	Pre-Tax Cost of Capital/12	0.74%	0.74%	0.74%	0.73%	0.73%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%

(1) Per Exhibit A-9

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Pre-tax Rate of Return
Based on ROE and Debt to Equity ratios
Authorized in Case No. U-15244
Debt Cost Per U-21297/ ROE Weighted

Case No.: U-21662
Exhibit: A-25 Sch. B1
Witness: K. Vangilder
Page: 2 of 2

Line No.	(a) Description	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040	(u) 2041	(v) 2042	(w) 2043	(x) 2044	(y) 2045
1	Debt Ratio	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%	51.22%
2	Debt Cost	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
3	Revenue Conversion	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
4	Debt Component	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%	2.08%
5	Equity Ratio	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%	48.78%
6	Equity Cost (1)	9.96%	9.95%	9.95%	9.94%	9.94%	9.93%	9.93%	9.93%	9.93%	9.92%	9.92%	9.92%
7	Revenue Conversion	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964	1.34964
8	Equity Component	6.56%	6.55%	6.55%	6.55%	6.54%	6.54%	6.54%	6.54%	6.53%	6.53%	6.53%	6.53%
9	Pre-Tax Cost of Capital	8.64%	8.63%	8.63%	8.62%	8.62%	8.62%	8.62%	8.61%	8.61%	8.61%	8.61%	8.61%
10	Pre-Tax Cost of Capital/12	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%	0.72%

(1) Per Exhibit A-9

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Revenue Conversion Factor & Effective Tax Rate

Case No.: U-21662
Exhibit: A-25 Sch. B2
Witness: K. Vangilder
Page: 1 of 1

Revenue Conversion Factor

Line No.	Revenue Conversion Factor	(a) 2018-2045 Debt Conversion Percent	(b) 2018-2045 Equity Conversion Percent
1	Base	100.00%	100.00%
2	MCIT Income Tax (1)		5.88%
3	Municipal Tax Base (L1 - L2)	100.00%	94.12%
4	Municipal Tax Rate (1)		0.33%
5	FIT Base (L4 - L5)	100.00%	93.79%
6	FIT Rate (1)		21.00%
7	FIT Tax (L5 x L6)	0.00%	19.70%
8	Income (L5 - L7)	100.00%	74.09%
9	Revenue Multiplier (L1 / L8)	1.0000	1.3496
10	Cumulative Effective Tax Rate (1 - line 8, col b)		25.90%

1/ Provided by DTE Tax Department

Michigan Public Service Commission Case No.: U-21662
DTE Electric Company Exhibit: A-25 Sch. B3
2024 Amended REP Witness: K. Vangilder
Pre-Tax Rate of Return and Revenue Conversion Factors Page: 1 of 1
Based on Authorized ROE and Debt to Equity ratios
Authorized in Case No. U-15244 and U-20561, Debt Cost from U-21297

Pre-Tax Rate of Return and Revenue Conversion Factors

Line No.		(a) Ratio	(b) Cost	(c) Regulated RoR	(d) Revenue Conversion	(e) Pre Tax RoR
1	Debt	51.22% (1)	4.06% (2)	2.077%	1.0000	2.077%
2	Equity	48.78% (1)	9.90% (3)	4.829%	1.3496	6.518%
3		100.00%		**6.91%**		**8.59%**

(1) Permanent capital structure as authorized in Case No. U-15244
(2) Long Term Debt Cost as authorized in Case No. U-21297
(3) Return on Equity as authorized in Case No. U-20561

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Actual and Forecast Meter Counts by Class

Case No.: U-21662
Exhibit: A-26
Witness: K. Vangilder
Page: 1 of 1

	(a)	(b)	(c)	(d)
		BUNDLED CUSTOMER METERS BY CLASS		
LINE NO.	YEAR	RESIDENTIAL	COMMERCIAL SECONDARY	COMMERCIAL / INDUSTRIAL PRIMARY
1	2022	2,047,591	207,478	2,816
2	2023	2,055,845	208,286	2,823
3	2024	2,064,797	209,555	2,818
4	2025	2,074,827	210,629	2,818
5	2026	2,084,117	211,588	2,818
6	2027	2,092,054	212,397	2,818
7	2028	2,098,709	213,071	2,818
8	2029	2,104,525	213,660	2,818
9	2030	2,110,138	214,227	2,818
10	2031	2,115,485	214,767	2,818
11	2032	2,120,393	215,263	2,818
12	2033	2,125,749	215,804	2,818
13	2034	2,131,503	216,385	2,818
14	2035	2,136,966	216,937	2,818
15	2036	2,141,956	217,441	2,818
16	2037	2,146,350	217,885	2,818
17	2038	2,150,168	218,271	2,818
18	2039	2,153,450	218,603	2,818
19	2040	2,156,186	218,879	2,818
20	2041	2,158,382	219,101	2,818
21	2042	2,160,663	219,331	2,818
22	2043	2,163,523	219,620	2,818
23	2044	2,166,450	219,916	2,818
24	2045	2,169,196	220,193	2,818

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRI L. WISNIEWSKI

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHERRI L. WISNIEWSKI

Line No

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

A1. My name is Sherri L. Wisniewski (she/her/hers). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC.

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 earned a Bachelor of Business Administration from Western Michigan University in 1993 and a Master of Business Administration from The University of Michigan in 1998.

Q4. What work experience do you have?

A4. I have been with DTE Energy in the Tax Department since 1996 and became Director of Tax Operations in July 2016 and am currently responsible for tax accounting, tax forecasting, and regulatory tax.

Q5. Have you previously sponsored testimony before the Michigan Public Service Commission (MPSC or Commission)?

A5. Yes. I have sponsored testimony in the following cases:

U-18232	DTE Electric REP Amended Plan
U-18232	DTE Electric 2020 Amended REP Plan - March 2020
U-18255	DTE Electric Rate Case
U-18999	DTE Gas Rate Case
U-20029	DTE Electric EWR 2017 Reconciliation
U-20051	DTE Electric 2017 TRM Reconciliation
U-20105	DTE Electric Credit A Rate Case
U-20106	DTE Gas Credit A Rate Case
U-20162	DTE Electric Rate Case
U-20172	DTE Electric REP 2017 Reconciliation
U-20298	DTE Gas Calculation C
U-20484	DTE Electric REP 2018 Reconciliation
U-20561	DTE Electric Rate Case
U-20642	DTE Gas Rate Case
U-20723	DTE Electric REP 2019 Reconciliation
U-20835	DTE Electric Company for Accounting Approval to Accelerate Amortization of the Tax Cuts and Job Act Regulatory Liability for Non-Plant Related Accumulated Deferred Income Taxes
U-20851	DTE Electric 2020 Amended REP Plan
U-20940	DTE Gas Rate Case
U-21010	DTE Electric 2020 REP Reconciliation
U-20836	DTE Electric Rate Case

Line No		
1	U-21285	DTE Electric 2022 Amended REP Plan
2	U-21198	DTE Electric 2021 REP Reconciliation
3	U-21291	DTE Gas Rate Case
4	U-21297	DTE Electric Rate Case
5	U-21353	DTE Electric REP 2022 Reconciliation
6	U-21361	DTE Electric 2023 Amended REP Plan
7	U-21550	DTE Electric REP 2023 Reconciliations
8	U-21534	DTE Electric Rate Case

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to discuss and support the reasonableness of deferred taxes, tax regulatory assets and liabilities, and property tax expense in DTE Electric's 2024 Renewable Energy Plan (REP).

Q7. Are you sponsoring any exhibits in this proceeding?

A7. I am sponsoring the following exhibit:

Exhibit	Description
A-27	Deferred Income Taxes and Tax Regulatory Assets and Liabilities

Q8. Was this exhibit prepared by you or under your direction?

A8. Yes, it was.

Q9. How do the deferred income tax assets and liabilities and tax regulatory assets and liabilities shown on Exhibit A-27 impact rate base?

Line No

A9. The average balance of deferred tax assets and liabilities and tax regulatory assets and liabilities shown on Exhibit A-27, line 39 is reflected as a reduction in rate base in Witness Kauffman's Exhibit A-9, line 11 for Compliance assets and line 20 for Authorized Large Customer Voluntary Green Pricing (VGP) program assets.

Q10. Please describe the deferred tax assets and liabilities and tax regulatory assets and liabilities shown on Exhibit A-27, Deferred Income Taxes.

A10. A brief overview of each item on Exhibit A-27 is described below.

- Lines 1 through 8: Deferred Tax Asset – Production Tax Credits (PTC). The deferred tax related to PTCs represents the PTCs that have been generated but not yet either utilized to reduce income taxes payable on a tax return or transferred to a 3rd party. PTCs are not refundable credits, and there are limits to how many credits can be utilized each year based on DTE Electric's Federal income tax liability. PTCs not used in the year generated or transferred to a 3rd party are carried forward and used in a future year.

- Lines 9 through 14: Deferred Tax Liability – Plant. The deferred tax related to plant results from differences between accelerated tax depreciation and book depreciation as well as differences in depreciable basis for book and tax resulting from AFUDC equity and Investment Tax Credits (ITCs).
    - Tax depreciation is calculated utilizing a methodology that generally results in a faster depreciation of the investment as compared to the methodology used to calculate book depreciation resulting in a deferred tax liability.

- Book depreciable basis is increased by the amount of AFUDC Equity recognized, but there is no increase in the tax depreciable basis. Therefore, a deferred tax liability is established on this basis difference.
- When an asset generates an ITC, the tax depreciable basis must be reduced by 50% of that credit but there is no reduction in the book depreciable basis. Therefore, a deferred tax liability is established on this basis difference.

- Lines 15 through 20: Deferred Tax Asset – REP Reg. Liability. The deferred tax related to the regulatory liability results from the revenue DTE Electric previously collected through the REP Surcharge that initially exceeded the incremental costs of compliance. The net is recorded as an increase in the regulatory liability. Taxes must be paid on the net increase in the regulatory liability, which creates a deferred tax asset. As the incremental costs of compliance exceeds the revenue received from the REP Surcharge, the regulatory liability balance, and the deferred tax asset will decrease.

- Lines 21 through 26: Deferred Tax Asset – Renewable Energy Credits. The deferred tax related to Renewable Energy Credits (RECs) results from the difference between book expense and tax expense. For book purposes, the RECs are expensed using a weighted-average cost method. For tax purposes, the RECs are expensed using specific identification, expensing each REC at its original cost when acquired or generated.

- Lines 27 through 32: AFUDC Equity Tax Regulatory Asset. The tax regulatory asset is established to offset the plant deferred tax liability that is established related to AFUDC Equity basis difference. The regulatory asset is amortized over the book life of the asset.

- Lines 33 through 38: TCJA Tax Regulatory Liability. The tax regulatory liability represents the remeasurement of deferred taxes at 12/31/2017 due to the Tax Cuts and Jobs Act (TCJA), which reduced the federal corporate income tax rate from 35% to 21%. The TJCA tax regulatory liability represents the excess deferred income taxes that are flowed back to the customer as the regulatory liability is amortized. The regulatory liability amortization continues to follow the same overall methodology approved in DTE Electric's Case No. U-20162.

Q11. How do the tax regulatory assets and liabilities shown on Exhibit A-27 impact the incremental cost of compliance on Witness Vangilder's Exhibit A-22?

A11. The amortization of the AFUDC Equity Tax Regulatory Asset shown on line 29 of Exhibit A-27 is reflected as an increase to the incremental cost of compliance on Witness Vangilder's Exhibit A-22, line 29.

The amortization of the TCJA Tax Regulatory Liability shown on line 34 of Exhibit A-27 is reflected as a reduction to the incremental cost of compliance on Witness Vangilder's Exhibit A-22, line 23. Since the amortization of the TCJA regulatory liability is a post-tax adjustment, it must be grossed up (increased) for taxes to include it in the pre-tax incremental cost of compliance. This gross up decreases the

revenue requirement included in the REP Surcharge and ensures DTE Electric does not earn above its authorized return for this amortization.

Q12. How do property taxes impact this REP filing?

A12. Property tax expense is a component of revenue requirements as shown on Witness Vangilder's Exhibit A-23, line 20.

Q13. How is the property tax expense shown on Witness Vangilder's Exhibit A-23, line 20 calculated?

A13. To calculate property tax expense, the property tax liability must first be calculated. The property tax liability is calculated by multiplying the ending plant in service and CWIP by an estimated composite property tax rate that is based on 2023 property tax bills. The property tax liability is then expensed over a two-year period, with the liability of each year being expensed 39% the current year and 61% the subsequent year. This two-year allocation methodology has been used for many years and is based, generally, on the fiscal years of the various taxing jurisdictions to which property taxes are paid.

Q14. Does this complete your direct testimony?

A14. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

SHERRI L. WISNIEWSKI

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Deferred Income Taxes and Tax Regulatory Assets and Liabilities
($ Millions, except where noted)

Case No.: U-21662
Exhibit: A-27
Witness: S. L. Wisniewski

Line No.	(a) Description	(b) As Filed 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033
1	**Deferred Tax Asset -- PTC**												
2	Beginning Balance	241.0	354.0	421.0	328.7	281.7	240.0	191.1	131.4	16.2	-	-	-
3	Generated	82.7	79.4	82.2	89.9	100.7	175.4	247.8	334.6	397.1	440.6	469.7	535.0
4	Transferred	-	-	(161.7)	(89.9)	(100.7)	(175.4)	(247.8)	(334.6)	(397.1)	(440.6)	(469.7)	(535.0)
5	Utilized	-	(12.4)	(12.9)	(47.0)	(41.7)	(48.9)	(59.7)	(115.2)	(16.2)	-	-	-
6	Cumulative True-Up to Prior Year Actuals **(Note 2)**	30.3											
7	Ending Balance	354.0	421.0	328.7	281.7	240.0	191.1	131.4	16.2	-	-	-	-
8	Average Balance	297.5	387.5	374.9	305.2	260.9	215.6	161.3	73.8	8.1	-	-	-
9	**Deferred Tax Liability -- Plant**												
10	Beginning Balance	(297.2)	(350.1)	(392.6)	(438.9)	(511.3)	(635.1)	(844.3)	(1,125.8)	(1,398.5)	(1,660.8)	(1,912.8)	(2,133.3)
11	Book / Tax Timing Difference **(Note 1)**	(52.8)	(42.6)	(46.3)	(72.3)	(123.8)	(209.2)	(281.5)	(272.8)	(262.2)	(252.0)	(220.5)	(178.0)
12	Re-measurement Adjustment												
13	Ending Balance	(350.1)	(392.6)	(438.9)	(511.3)	(635.1)	(844.3)	(1,125.8)	(1,398.5)	(1,660.8)	(1,912.8)	(2,133.3)	(2,311.4)
14	Average Balance	(323.6)	(371.3)	(415.8)	(475.1)	(573.2)	(739.7)	(985.0)	(1,262.2)	(1,529.7)	(1,786.8)	(2,023.1)	(2,222.4)
15	**Deferred Tax Asset -- REP Reg. Liability**												
16	Beginning Balance	3.2	6.0	2.4	6.4	41.9	64.7	47.9	4.1	1.0	1.0	6.8	28.9
17	Reg Liability Activity	2.8	(3.6)	4.0	35.5	22.9	(16.8)	(43.8)	(3.2)	(0.0)	5.8	22.2	18.1
18	Re-measurement Adjustment												
19	Ending Balance	6.0	2.4	6.4	41.9	64.7	47.9	4.1	1.0	1.0	6.8	28.9	47.1
20	Average Balance	4.6	4.2	4.4	24.1	53.3	56.3	26.0	2.6	1.0	3.9	17.9	38.0
21	**Deferred Tax Asset -- Renewable Energy Credits**												
22	Beginning Balance	(0.1)	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
23	Renewable Energy Credit Activity	(0.1)	(0.1)	-	-	-	-	-	-	-	-	-	-
24	Re-measurement Adjustment												
25	Ending Balance	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
26	Average Balance	(0.1)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
27	**AFUDC Equity Tax Regulatory Asset**												
28	Beginning Balance	-	-	2.1	20.9	53.6	102.8	136.6	167.4	190.7	214.7	233.5	257.0
29	Establish AFUDC Equity Tax Regulatory Asset	-	2.1	18.8	33.2	51.1	37.6	36.7	31.0	33.4	29.7	36.0	38.2
30	AFUDC Equity Tax Regulatory Asset Amortization	-	-	(0.1)	(0.6)	(1.8)	(3.8)	(6.0)	(7.7)	(9.4)	(10.9)	(12.4)	(14.0)
31	Ending Balance	-	2.1	20.9	53.6	102.8	136.6	167.4	190.7	214.7	233.5	257.0	281.3
32	Average Balance	-	1.1	11.5	37.3	78.2	119.7	152.0	179.0	202.7	224.1	245.3	269.1
33	**TCJA Tax Regulatory Liability**												
34	Beginning Balance	(78.8)	(75.9)	(73.6)	(71.2)	(68.8)	(66.4)	(64.0)	(61.6)	(59.2)	(56.8)	(54.4)	(51.9)
35	Amortization	2.8	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	3.6
36	Re-measurement Adjustment												
37	Ending Balance	(75.9)	(73.6)	(71.2)	(68.8)	(66.4)	(64.0)	(61.6)	(59.2)	(56.8)	(54.4)	(51.9)	(48.3)
38	Average Balance	(77.4)	(74.8)	(72.4)	(70.0)	(67.6)	(65.2)	(62.8)	(60.4)	(58.0)	(55.6)	(53.1)	(50.1)
39	**Total Deferred Taxes and Tax Regulatory Assets & Liabilities -- Ending Balance**	(66.1)	(40.8)	(154.3)	(203.1)	(294.1)	(532.8)	(884.7)	(1,250.1)	(1,502.2)	(1,727.2)	(1,899.5)	(2,031.6)
40	**Total Average Deferred Taxes and Tax Regulatory Assets & Liabilities -- Rate Base**	(99.0)	(53.5)	(97.6)	(178.7)	(248.6)	(413.5)	(708.7)	(1,067.4)	(1,376.1)	(1,614.7)	(1,813.3)	(1,965.6)
41	**(Note 1)**												
42	Tax Depreciation	(298.3)	(261.9)	(236.1)	(265.4)	(463.2)	(1,011.3)	(1,423.6)	(1,494.0)	(1,509.0)	(1,565.1)	(1,476.4)	(1,390.8)
43	Book Depreciation	92.4	99.3	109.5	140.6	202.8	344.0	415.9	497.2	553.2	632.5	677.1	755.6
44	AFUDC Debt -- Book	-	-	(23.2)	(40.9)	(62.8)	(46.3)	(45.2)	(38.2)	(41.1)	(36.6)	(44.3)	(47.0)
45	AFUDC Debt -- Tax	-	-	43.5	76.7	118.0	86.8	84.9	71.7	77.1	68.7	83.2	88.3
46	Difference	(205.9)	(162.6)	(106.3)	(89.0)	(205.3)	(626.7)	(968.1)	(963.3)	(919.9)	(900.5)	(760.4)	(593.9)
47	Effective Tax Rate	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%
48	Deferred Tax (Expense) / Income	(53.3)	(42.1)	(27.5)	(23.0)	(53.2)	(162.3)	(250.7)	(249.5)	(238.2)	(233.2)	(196.9)	(153.8)
49	Deferred Taxes on AFUDC Equity	-	-	(18.8)	(33.2)	(51.1)	(37.6)	(36.7)	(31.0)	(33.4)	(29.7)	(36.0)	(38.2)
50	Amortization of Deferred Taxes on AFUDC Equity	-	-	0.1	0.6	1.8	3.8	6.0	7.7	9.4	10.9	12.4	14.0
51	Deferred Taxes -- ITC Basis Adjustment	-	-	-	(16.6)	(21.4)	(13.1)	-	-	-	-	-	-
52	Deferred Taxes -- Other Adjustments	0.5	(0.4)	-	-	-	-	-	-	-	-	-	-
53	Deferred Tax Activity -- Plant	(52.8)	(42.6)	(46.3)	(72.3)	(123.8)	(209.2)	(281.5)	(272.8)	(262.2)	(252.0)	(220.5)	(178.0)
54	Composite Tax Rate	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%

55 **(Note 2)** -- Represents a manual adjustment to agree to prior year's return to accrual adjustment.

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Deferred Income Taxes and Tax Regulatory Assets and Liabilities
($ Millions, except where noted)

Case No.: U-21662
Exhibit: A-27
Witness: S. L. Wisniewski
Page: 2 of 2

Line No.	(a) Description	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040	(u) 2041	(v) 2042	(w) 2043	(x) 2044	(y) 2045
1	**Deferred Tax Asset -- PTC**												
2	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-
3	Generated	584.6	702.0	783.7	778.5	786.0	772.8	876.3	896.7	939.2	875.3	851.7	788.2
4	Transferred	(584.6)	(702.0)	(783.7)	(778.5)	(786.0)	(772.8)	(876.3)	(896.7)	(939.2)	(875.3)	(851.7)	(788.2)
5	Utilized	-	-	-	-	-	-	-	-	-	-	-	-
6	Cumulative True-Up to Prior Year Actuals **(Note 2)**												
7	Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-
8	Average Balance	-	-	-	-	-	-	-	-	-	-	-	-
9	**Deferred Tax Liability -- Plant**												
10	Beginning Balance	(2,311.4)	(2,490.1)	(2,673.1)	(2,855.6)	(3,039.5)	(3,221.8)	(3,394.3)	(3,554.7)	(3,694.7)	(3,801.9)	(3,822.9)	(3,707.5)
11	Book / Tax Timing Difference **(Note 1)**	(178.8)	(183.0)	(182.5)	(183.9)	(182.4)	(172.5)	(160.3)	(140.0)	(107.2)	(21.1)	115.4	198.9
12	Re-measurement Adjustment												
13	Ending Balance	(2,490.1)	(2,673.1)	(2,855.6)	(3,039.5)	(3,221.8)	(3,394.3)	(3,554.7)	(3,694.7)	(3,801.9)	(3,822.9)	(3,707.5)	(3,508.6)
14	Average Balance	(2,400.7)	(2,581.6)	(2,764.3)	(2,947.5)	(3,130.6)	(3,308.1)	(3,474.5)	(3,624.7)	(3,748.3)	(3,812.4)	(3,765.2)	(3,608.1)
15	**Deferred Tax Asset -- REP Reg. Liability**												
16	Beginning Balance	47.1	17.1	5.8	16.1	19.7	22.2	18.1	49.1	87.2	140.7	205.4	293.5
17	Reg Liability Activity	(30.0)	(11.3)	10.3	3.6	2.5	(4.1)	31.0	38.1	53.5	64.6	88.2	92.8
18	Re-measurement Adjustment												
19	Ending Balance	17.1	5.8	16.1	19.7	22.2	18.1	49.1	87.2	140.7	205.4	293.5	386.3
20	Average Balance	32.1	11.4	10.9	17.9	20.9	20.1	33.6	68.2	114.0	173.1	249.5	339.9
21	**Deferred Tax Asset -- Renewable Energy Credits**												
22	Beginning Balance	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
23	Renewable Energy Credit Activity	-	-	-	-	-	-	-	-	-	-	-	-
24	Re-measurement Adjustment												
25	Ending Balance	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
26	Average Balance	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
27	**AFUDC Equity Tax Regulatory Asset**												
28	Beginning Balance	281.3	305.6	328.9	350.7	371.0	389.6	406.1	418.0	415.9	389.3	357.4	325.3
29	Establish AFUDC Equity Tax Regulatory Asset	40.2	40.9	41.4	41.8	42.2	42.1	39.6	27.4	4.6	-	-	-
30	AFUDC Equity Tax Regulatory Asset Amortization	(15.8)	(17.7)	(19.6)	(21.6)	(23.6)	(25.6)	(27.6)	(29.6)	(31.2)	(32.0)	(32.1)	(32.1)
31	Ending Balance	305.6	328.9	350.7	371.0	389.6	406.1	418.0	415.9	389.3	357.4	325.3	293.2
32	Average Balance	293.4	317.3	339.8	360.8	380.3	397.8	412.1	417.0	402.6	373.3	341.3	309.2
33	**TCJA Tax Regulatory Liability**												
34	Beginning Balance	(48.3)	(44.0)	(39.5)	(35.1)	(30.6)	(26.0)	(21.5)	(17.0)	(12.4)	(8.4)	(4.3)	(0.2)
35	Amortization	4.3	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.1	4.1	4.1	0.2
36	Re-measurement Adjustment												
37	Ending Balance	(44.0)	(39.5)	(35.1)	(30.6)	(26.0)	(21.5)	(17.0)	(12.4)	(8.4)	(4.3)	(0.2)	0.0
38	Average Balance	(46.1)	(41.8)	(37.3)	(32.8)	(28.3)	(23.8)	(19.2)	(14.7)	(10.4)	(6.3)	(2.2)	(0.1)
39	**Total Deferred Taxes and Tax Regulatory Assets & Liabilities -- Ending Balance**	(2,211.6)	(2,378.2)	(2,524.1)	(2,679.6)	(2,836.3)	(2,991.9)	(3,104.7)	(3,204.3)	(3,280.4)	(3,264.7)	(3,089.1)	(2,829.3)
40	**Total Average Deferred Taxes and Tax Regulatory Assets & Liabilities -- Rate Base**	(2,121.6)	(2,294.9)	(2,451.2)	(2,601.9)	(2,758.0)	(2,914.1)	(3,048.3)	(3,154.5)	(3,242.3)	(3,272.6)	(3,176.9)	(2,959.2)
41	**(Note 1)**												
42	Tax Depreciation	(1,470.0)	(1,556.7)	(1,627.5)	(1,702.0)	(1,770.8)	(1,810.0)	(1,847.3)	(1,880.7)	(1,895.7)	(1,564.4)	(1,038.9)	(715.2)
43	Book Depreciation	830.6	895.9	962.3	1,025.0	1,093.2	1,162.0	1,231.7	1,302.2	1,374.2	1,359.7	1,360.7	1,359.4
44	AFUDC Debt -- Book	(49.4)	(50.4)	(50.9)	(51.5)	(52.0)	(51.8)	(48.7)	(33.7)	(5.7)	-	-	-
45	AFUDC Debt -- Tax	92.8	94.6	95.6	96.7	97.6	97.2	91.5	63.3	10.7	-	-	-
46	Difference	(596.0)	(616.6)	(620.5)	(631.8)	(632.0)	(602.6)	(572.8)	(548.9)	(516.5)	(204.7)	321.7	644.2
47	Effective Tax Rate	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%
48	Deferred Tax (Expense) / Income	(154.4)	(159.7)	(160.7)	(163.6)	(163.7)	(156.1)	(148.4)	(142.2)	(133.8)	(53.0)	83.3	166.8
49	Deferred Taxes on AFUDC Equity	(40.2)	(40.9)	(41.4)	(41.8)	(42.2)	(42.1)	(39.6)	(27.4)	(4.6)	-	-	-
50	Amortization of Deferred Taxes on AFUDC Equity	15.8	17.7	19.6	21.6	23.6	25.6	27.6	29.6	31.2	32.0	32.1	32.1
51	Deferred Taxes -- ITC Basis Adjustment	-	-	-	-	-	-	-	-	-	-	-	-
52	Deferred Taxes -- Other Adjustments	-	-	-	-	-	-	-	-	-	-	-	-
53	Deferred Tax Activity -- Plant	(178.8)	(183.0)	(182.5)	(183.9)	(182.4)	(172.5)	(160.3)	(140.0)	(107.2)	(21.1)	115.4	198.9
54	Composite Tax Rate	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%	25.9%

55 **(Note 2)** -- Represents a manual adjustment to agree to prior year's re

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

EMILY C. MELOCHE

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF EMILY C. MELOCHE

Line No

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

A1. My name is Emily C. Meloche (she/her/hers). My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company.

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 Commerce degree with concentrations in Finance and Strategy & Entrepreneurship from University of Windsor in 2018. 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. I joined the Company in May 2016 as an intern in Demand Response for DTE Electric. I transitioned to a co-op within the same group in September 2017. While in Demand Response I completed enrollments in the SmartCurrents program and tracked new equipment installations for the CoolCurrents program. In January 2019, I joined the Corporate Energy Forecasting team as an Associate Energy Analyst. In June 2021, I was promoted to Data Analyst within the same group.

Q5. What are your duties as Data Analyst, Corporate Energy Forecasting?

A5. I am responsible for the data collection, statistical analysis and interactions with other departments to create the long-term sales forecast (one year or greater) and short-term sales forecast (monthly)

Line
No

Purpose of Testimony

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to provide DTE Electric's current electric sales forecast for the period 2024-2045 and to explain the basis for this forecast. In addition, I am supporting the customer count projection for the period 2024-2045.

Q7. Are you sponsoring any exhibits?

A7. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-28	Annual Service Area Sales
A-29	Annual Bundled Sales
A-30	Annual Electric Choice Sales
A-31	Summary of Economic Outlook
A-32	Annual Customer Count

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 parts:

Part I: Economic Outlook

Part II: Forecast Development and Assumptions

Part III: Electric Load and System Output Forecast

Line No

Part I: Economic Outlook

Q10. What is the outlook for the national economy in 2024 compared to 2023?

A10. Real gross domestic product is expected to increase by 1.3%, real personal consumption expenditures by 1.2%, and real disposable personal income by 2.6%. The CPI-U is forecast to increase by 2.7%. Total light vehicle production in the United States is forecast to reach 10.66 million units, an increase of 5.6%.

Q11. What is the outlook for Southeast Michigan's economy in 2024 compared to 2023?

A11. Total non-farm employment is forecasted to decrease by 0.6%. Natural resources, mining, and construction employment is expected to decrease by 2.5%, manufacturing employment is expected to decrease by 4.3%, government employment is expected to increase by 0.7%, and total private non-manufacturing employment is forecasted to decrease by 0.2%. Southeast Michigan's automotive production is expected to reach a level of 1.46 million vehicles, an increase of 2.8%. Population is forecasted to increase by 0.1%.

Part II: Forecast Development and Assumptions

Q12. What is the general approach used in developing the forecast of DTE Electric's service area electric sales and system output?

A12. 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.

Line
No

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: S&P Global (formerly IHS Markit,) Moody's Analytics, and Polk Automotive
- The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2022 end-use intensity and end-use saturation estimates for the East North Central Census Division (modified for DTE Electric's end-use information)

- A workplace occupancy index sourced from Kastle to model the ongoing effects of work from home marketplace dynamics
- Historical weather data from the Detroit Metropolitan Airport, with normal weather assumptions in the forecast horizon
- DTE Electric's Energy Waste Reduction (EWR) targets
- DTE Electric's behind-the-meter distributed generation (DG) projections
- DTE Electric's electric vehicle (EV) forecast for light-duty and fleet vehicles
- Large customer load adjustments that would not be reflected in the historical data or economic projections

Q13. Can you describe the data used to construct the forecast models?

A13. Each model to forecast sales was estimated with monthly historical consumption data beginning in January 2006, with estimation ending in June 2023. Customer count forecast models were estimated with monthly historical customer count data beginning in January 2010, with estimation ending in June 2023.

Q14. How is weather applied in the load forecast?

A14. 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.

Q15. Please describe the HDD and CDD bases used in the forecast.

A15. 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 but 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. 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

Line
No

Figure 1 Figure 1: Residential Daily Use-Per-Customer vs Temperature

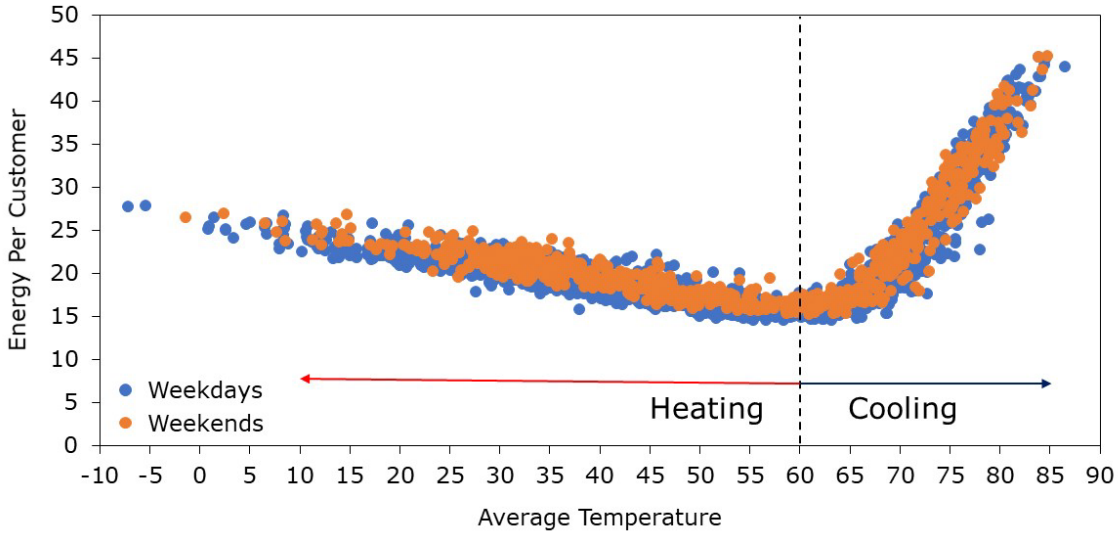
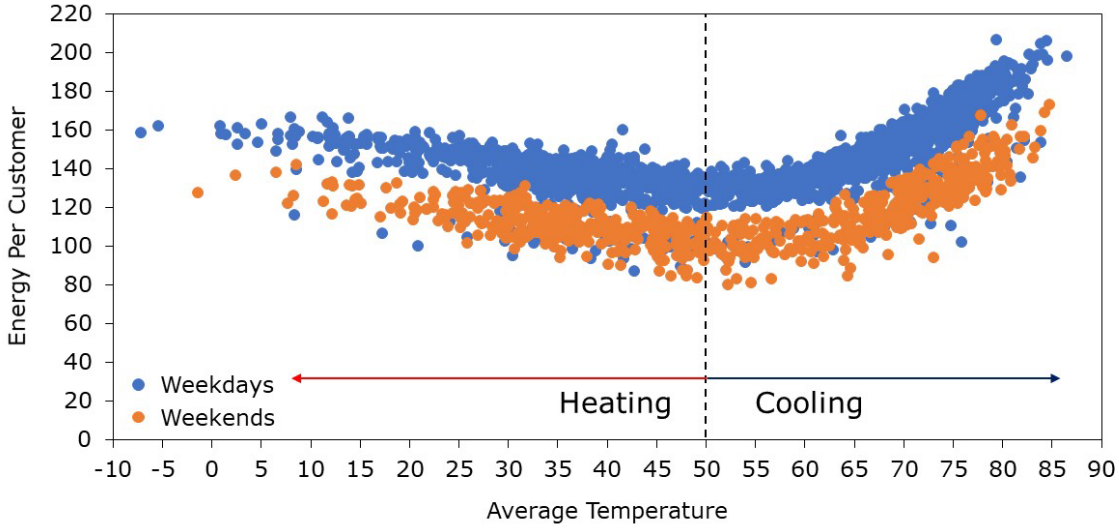


Figure 2 Small C&I Daily Use-Per-Customer vs Temperature



Q16. How does DTE Electric define normal weather?

A16. Normal weather is defined as a 15-year average of historical values, updated on an annual cadence. 2008-2022 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.

Q17. How was the residential class forecast developed?

A17. 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 begins 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 2022 for the East North Central region in which DTE Electric operates. Residential EWR programs are applied directly to the corresponding end-uses 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, workplace occupancy index data was integrated into the model due to the shift in electricity consumption patterns caused by work from home practices. The utilization variables are then combined with the end-use intensities to compute three explanatory variables that are:

Line No

- XHeat – An aggregated heating variable that captures changes in heating end-use saturation and efficiency, and combined with HDDs, economic, and other factors that impact the utilization of heating equipment
- XCool – An aggregated cooling variable that captures changes in cooling end-use saturation and efficiency, and combined with CDDs, economic, and other factors that impact the utilization of cooling equipment
- XOther – An aggregated base-load variable that captures changes in base-load end-use saturation and efficiency, and combined with number of days in a month, economic, and other factors that impact the utilization of base-load equipment

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 S&P Global. 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.

Q18. How was the small C&I forecast developed?

A18. 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,

Line
No

C&I EWR programs are incorporated directly into the SAE model. The small C&I sales forecast begins with a basic end-use model with saturation projections and average electricity usage per end-use derived from the EIA's AEO 2022 for the East North Central region in which DTE Electric operates. Since not all small C&I buildings within the DTE Electric service territory consume electricity the same, 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 weight 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 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 Small C&I explanatory variables that are XHeat, XCool, and XOther, similar to Residential as described above.

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.

Small C&I customers are modeled using a regression with households used 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.

Q19. How was the large C&I forecast developed?

A19. The large C&I forecast begins 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, transportation trade and utility (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 electric vehicles. 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 two post regression adjustments include EV electrification growth, and large customer projects that are informed by customer account managers.

Q20. What level of EWR is assumed in the forecast?

A20. The load forecast assumes EWR savings consistent with Case No. U-21322 and Case No. U-21193, the Company's most recent EWR Plan and Integrated Resource Plan filings respectively. For 2024, the Company plans to achieve 2% annual savings, made up of a 1.4% reduction in residential sales, and a 2.3% reduction in C&I sales.

Q21. What type of DG resources were included in the forecast?

A21. 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. The annual DG outflows are outlined in Exhibit A-29. For forecasting purposes, the projected additional DG resources were assumed to be solar photovoltaics (PV).

Q22. How was the DG outlook applied to the forecast?

A22. The DG outlook was developed utilizing the Company's residential and non-residential interconnection history. The forecast begins with a collection of historical and projected PV economics for both residential and non-residential customers. Variables such as, but not limited to, capital costs, operating and manufacturing costs, tax credit schedules, and electricity prices were used to determine the PV economics. These economics are used as the primary explanatory

variable in a regression model, with the Company's interconnection history as the dependent variable, to project the levels of DG expected in the future.

Two separate forecasts are produced for residential and non-residential. The historical and forecast DG is applied directly as an additional end-use into the models for residential and small C&I.

Q23. How was the EV outlook applied to the forecast?

A23. For the EV forecast, the Company utilized historical trends and other industry experts[1] 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 and large C&I models as a starting point. Over time, as EV adoption becomes more mainstream, the forecast assumes these dynamics will shift

1 BNEF (national), Goldman Sachs (national), EPRI (Michigan), International Council on Clean Transportation (non-zero emission vehicle states), Boston Consulting Group (national), and EIA (East North Central) were used for the updated forecast

in favor of more non-residential charging. As public infrastructure is built out to support direct current (DC) fast charging and consumers without access to home charging begin to adopt EVs, 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.

Q24. How was the Electric Choice sales forecast developed?

A24. 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.

Part III: Electric Load and System Output Forecast

Q25. What has been the compound annual growth rate of DTE Electric's service area sales over the last few years?

A25. As shown in Exhibit A-28, on a temperature-normalized basis, service area sales decreased from 45,442 GWh in 2021 to 44,713 GWh in 2023. This represents a compound annual growth rate (CAGR) of -0.8%. As shown in Exhibit A-29, bundled sales have decreased at a similar rate, from 41,107 GWh in 2021 to 40,315 GWh in 2023, representing a CAGR of -1.0%. As shown on Exhibit A-30, the electric choice sales increased from 4,334 GWh in 2021 to 4,398 GWh in 2023 by a CAGR of 0.7%. Refer to Exhibits A-28, A-29, and A-30 for additional detail regarding historical actual sales for service area, bundled and electric choice.

Line
No

Q26. What is the CAGR of DTE Electric's service area and bundled sales from 2023 through the forecast period?

A26. DTE Electric's service area sales are forecast to increase from temperature-normalized sales of 44,713 GWh in 2023 to 47,793 GWh in 2045. This represents a 0.3% CAGR. Similarly, bundled sales are forecast to increase from temperature-normalized sales of 40,315 GWh in 2023 to 43,025 GWh in 2045. This represents a 0.3% CAGR. The electric choice sales are forecast to increase from temperature-normalized sales of 4,398 GWh in 2023 to 4,768 GWh in 2045. This represents a 0.4% CAGR.

Q27. What is the outlook for Residential Class sales?

A27. DTE Electric's service area residential Class sales are forecasted to increase by 0.6% annually, on average between 2023 and 2045. Modest average annual growth of 0.2% in residential customer count is expected through 2045. Use-per-customer through 2045 is expected to increase by 0.3% annually on average. Growth in residential is attributed to adoption of other appliances, customer growth, and an uptick in electric vehicle adoption.

Q28. What is the outlook for Small C&I class sales?

A28. DTE Electric's service area small C&I class sales are forecasted to increase by 0.3% through 2045. Modest average annual growth of 0.2% in small C&I customer count is expected through 2045 due to modest economic growth. Use-per-customer through 2045 is expected to increase by 0.1% annually on average. Stagnant economic growth, combined with EWR efforts primarily targeting C&I customers is projected to sustain an ongoing declining trend.

Line
No

Q29. What is the outlook for the Large C&I class sales?

A29. DTE Electric's service area large C&I class sales are expected to increase by 0.1% annually, on average, from 2023 through 2045. As mentioned previously, large C&I class sales are allocated between seven supersector markets. Out of the seven supersectors, TTU, offices, automotive and other manufacturing are all declining due to any increases from economic growth being constrained by energy efficiency efforts. Education & health and other markets are projected to increase due to an expansion at a hospital and a new cryptocurrency facility, respectively. Steel is projected to remain relatively flat.

Q30. What is the outlook for Other Class sales?

A30. DTE Electric's service area Other Class sales are expected to decrease 0.1% annually, on average, from 2023 through 2045. 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.

Q31. Does this conclude your direct testimony?

A31. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

OF

EMILY C. MELOCHE

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Annual Service Area Sales
2018-2023 Historical; 2024-2045 Forecast

Case No.: U-21662
Exhibit: A-28
Witness: E. C. Meloche
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Annual Sales - GWh						
Line No.	Year	Residential	Small C&I	Large C&I	St Ltg	Pumping	Wholesale	Total
1	Actual							
2	2018	15,939	11,271	21,093	224	0	0	48,527
3	2019	15,066	10,948	20,382	226	0	0	46,623
4	2020	16,316	10,086	17,759	220	0	0	44,381
5	2021	16,387	10,768	18,469	216	0	0	45,839
6	2022	15,844	10,848	18,481	210	0	0	45,383
7	2023	14,452	10,559	18,271	204	0	0	43,485
8								
9	Temperature-Normalized (T-N) [1]							
10	2021 T-N	16,122	10,714	18,390	216	0	0	45,442
11	2022 T-N	15,647	10,791	18,434	210	0	0	45,081
12	2023 T-N	15,313	10,786	18,410	204	0	0	44,713
13								
14	Forecast							
15	2024	15,290	10,727	18,122	195	0	0	44,333
16	2025	15,274	10,678	18,044	193	0	0	44,189
17	2026	15,325	10,632	17,849	192	0	0	43,999
18	2027	15,402	10,604	17,632	191	0	0	43,830
19	2028	15,578	10,618	17,782	192	0	0	44,170
20	2029	15,679	10,606	17,748	194	0	0	44,227
21	2030	15,829	10,607	17,683	196	0	0	44,315
22	2031	15,983	10,627	17,685	198	0	0	44,492
23	2032	16,207	10,696	17,694	199	0	0	44,796
24	2033	16,347	10,731	17,718	201	0	0	44,997
25	2034	16,569	10,815	17,787	201	0	0	45,372
26	2035	16,782	10,900	17,851	201	0	0	45,734
27	2036	16,993	11,003	17,934	201	0	0	46,131
28	2037	17,070	11,040	18,018	201	0	0	46,328
29	2038	17,151	11,099	18,126	201	0	0	46,578
30	2039	17,201	11,145	18,237	201	0	0	46,784
31	2040	17,260	11,204	18,355	201	0	0	47,020
32	2041	17,205	11,206	18,457	201	0	0	47,069
33	2042	17,201	11,242	18,561	201	0	0	47,204
34	2043	17,229	11,295	18,664	201	0	0	47,390
35	2044	17,311	11,382	18,778	201	0	0	47,672
36	2045	17,294	11,422	18,876	201	0	0	47,793

1) Historical sales are weather-normalized based off the weather-normalization period used in that year. The forecast is weather normalized using years 2008-2022

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Annual Bundled Sales
2018-2023 Historical; 2024-2045 Forecast

Case No.: U-21662
Exhibit: A-29
Witness: E. C. Meloche
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
		Annual Sales - GWh									
Line No.	Year	Residential	Small C&I	Large C&I	St Ltg	Pumping	Wholesale	Total	Retail Sales (Total less Wholesale)	DG Outflows	Total Retail Sales with DG Outflows
1	Actual										
2	2018	15,939	10,343	17,284	224	0	0	43,789	43,789		
3	2019	15,066	10,083	16,698	226	0	0	42,073	42,073		
4	2020	16,315	9,329	14,765	220	0	0	40,629	40,629		
5	2021	16,386	9,938	14,943	216	0	0	41,482	41,482		
6	2022	15,844	10,014	14,830	210	0	0	40,898	40,898		
7	2023	14,452	9,766	14,701	204	0	0	39,122	39,122		
8											
9	Temperature-Normalized (T-N) [1]										
10	2021 T-N	16,121	9,890	14,881	216	0	0	41,107	41,107		
11	2022 T-N	15,647	9,962	14,791	210	0	0	40,610	40,610		
12	2023 T-N	15,313	9,981	14,817	204	0	0	40,315	40,315		
13											
14	Forecast										
15	2024	15,290	9,901	14,492	195	0	0	39,878	39,878	(36.18)	39,914
16	2025	15,274	9,856	14,432	193	0	0	39,756	39,756	(44.79)	39,800
17	2026	15,325	9,813	14,249	192	0	0	39,580	39,580	(55.36)	39,635
18	2027	15,402	9,789	14,048	191	0	0	39,430	39,430	(68.10)	39,498
19	2028	15,578	9,805	14,211	192	0	0	39,786	39,786	(83.17)	39,870
20	2029	15,679	9,787	14,150	194	0	0	39,810	39,810	(100.83)	39,911
21	2030	15,829	9,787	14,080	196	0	0	39,892	39,892	(121.20)	40,013
22	2031	15,983	9,805	14,075	198	0	0	40,061	40,061	(143.02)	40,204
23	2032	16,207	9,871	14,070	199	0	0	40,346	40,346	(164.70)	40,511
24	2033	16,347	9,900	14,068	201	0	0	40,517	40,517	(185.88)	40,703
25	2034	16,569	9,980	14,122	201	0	0	40,872	40,872	(204.72)	41,077
26	2035	16,782	10,059	14,155	201	0	0	41,197	41,197	(222.05)	41,419
27	2036	16,993	10,155	14,209	201	0	0	41,557	41,557	(239.75)	41,797
28	2037	17,070	10,184	14,260	201	0	0	41,715	41,715	(257.84)	41,972
29	2038	17,151	10,240	14,352	201	0	0	41,944	41,944	(276.31)	42,221
30	2039	17,201	10,282	14,442	201	0	0	42,126	42,126	(295.14)	42,421
31	2040	17,260	10,336	14,544	201	0	0	42,341	42,341	(313.92)	42,655
32	2041	17,205	10,334	14,626	201	0	0	42,367	42,367	(332.89)	42,700
33	2042	17,201	10,369	14,726	201	0	0	42,497	42,497	(352.79)	42,850
34	2043	17,229	10,420	14,818	201	0	0	42,669	42,669	(373.10)	43,042
35	2044	17,311	10,504	14,917	201	0	0	42,932	42,932	(393.67)	43,326
36	2045	17,294	10,537	14,993	201	0	0	43,025	43,025	(414.46)	43,440

1) Historical sales are weather-normalized based off the weather-normalization period used in that year. The forecast is weather normalized using years 2008-2022

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Annual Electric Choice Sales
2018-2023 Historical; 2024-2045 Forecast

Case No.: U-21662
Exhibit: A-30
Witness: E. C. Meloche
Page: 1 of 1

Line No.	(a) Year	(b) Annual Sales - GWh Residential	(c) Small C&I	(d) Large C&I	(e) Other	(f) Total
1	Actual					
2	2018	0	932	3,805	0	4,737
3	2019	1	866	3,684	0	4,550
4	2020	1	757	2,994	0	3,751
5	2021	1	830	3,526	0	4,357
6	2022	0	834	3,651	0	4,486
7	2023	0	793	3,569	0	4,363
8						
9	Temperature-Normalized (T-N) [1]					
10	2021 T-N	1	824	3,509	0	4,334
11	2022 T-N	0	829	3,643	0	4,472
12	2023 T-N	0	806	3,592	0	4,398
13						
14	Forecast					
15	2024	0	826	3,629	0	4,455
16	2025	0	822	3,612	0	4,434
17	2026	0	819	3,600	0	4,419
18	2027	0	816	3,584	0	4,400
19	2028	0	813	3,571	0	4,383
20	2029	0	819	3,598	0	4,417
21	2030	0	820	3,603	0	4,423
22	2031	0	822	3,610	0	4,432
23	2032	0	825	3,625	0	4,450
24	2033	0	831	3,649	0	4,480
25	2034	0	834	3,666	0	4,500
26	2035	0	841	3,696	0	4,538
27	2036	0	848	3,726	0	4,574
28	2037	0	855	3,758	0	4,613
29	2038	0	859	3,774	0	4,633
30	2039	0	864	3,794	0	4,658
31	2040	0	868	3,811	0	4,679
32	2041	0	872	3,830	0	4,702
33	2042	0	873	3,835	0	4,707
34	2043	0	875	3,846	0	4,721
35	2044	0	879	3,861	0	4,740
36	2045	0	884	3,884	0	4,768

1) Historical sales are weather-normalized based off the weather-normalization period used in that year. The forecast is weather normalized using years 2008-2022

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Summary of Economic Outlook
2018-2022 Historical; 2023-2045 Forecast

Case No.: U-21662
Exhibit: A-31
Witness: E. C. Meloche
Page: 1 of 1

Line No.	Year	Real Gross State Product (Billions $2012)	Real Personal Income (Billions $2012)	Consumer Price Index (1982-84=100)	Households (Thousands)	Population (Thousands)	U.S. Car & Truck Production Total (Th. Units)	Car & Truck Production Detroit Area (Th. Units)	U.S. Car & Truck Prod. Detroit 3 (Th. Units)	Manufacturing Employment (Thousands)
	(a) (b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	2018	466.4	467.6	251.1	4048.01	10071.16	11030.8	1557.2	5770.2	629.3
2	2019	467.8	472.6	255.7	4066.06	10078.08	10597.6	1553.4	5267.1	627.3
3	2020	447.9	519.2	258.8	4034.13	10061.78	8623.0	1073.7	4281.2	551.9
4	2021	483.9	516.0	271.0	4034.62	10035.31	8910.9	1312.5	4285.3	585.0
5	2022	490.4	492.4	292.7	4067.05	10036.59	9759.4	1365.0	4765.0	603.7
6										
7	2023	494.9	497.9	304.9	4100.72	10049.16	10096.9	1423.0	4727.1	608.2
8	2024	501.0	508.2	313.0	4130.49	10064.04	10661.9	1462.9	4709.8	592.0
9	2025	507.4	518.8	320.6	4151.95	10076.68	11083.0	1703.4	4904.4	575.9
10	2026	512.8	529.9	327.6	4171.19	10083.88	10762.1	1715.3	4683.2	563.9
11	2027	518.9	541.3	335.2	4190.15	10088.31	10783.8	1613.3	4481.0	557.3
12	2028	525.1	552.3	342.6	4208.6	10091.6	10961.9	1644.0	4700.2	551.1
13	2029	530.5	562.5	349.8	4225.0	10093.5	10956.3	1620.3	4665.8	544.4
14	2030	536.7	572.6	357.2	4239.0	10093.6	11029.4	1548.4	4721.1	538.3
15	2031	542.8	582.6	364.9	4252.6	10091.7	11052.5	1614.6	4725.6	533.4
16	2032	549.0	592.8	372.8	4266.7	10088.0	11075.6	1603.6	4731.0	528.3
17	2033	555.4	603.5	380.8	4279.9	10082.7	11098.8	1595.5	4745.7	523.5
18	2034	562.6	614.5	389.0	4290.4	10075.6	11122.0	1611.3	4753.9	523.7
19	2035	569.2	625.9	397.4	4299.6	10066.7	11145.2	1610.2	4763.4	524.7
20	2036	575.5	637.3	406.0	4308.6	10055.6	11168.5	1612.4	4774.2	525.4
21	2037	582.0	648.4	414.7	4317.1	10042.4	11191.9	1618.1	4783.8	527.0
22	2038	588.8	660.1	423.6	4325.2	10027.2	11215.3	1620.3	4793.8	528.7
23	2039	595.6	672.1	432.8	4332.6	10010.2	11238.8	1623.7	4803.9	530.5
24	2040	603.1	684.5	442.1	4339.9	9991.7	11262.3	1627.5	4813.9	531.4
25	2041	610.4	696.5	451.6	4347.1	9972.1	11285.8	1630.6	4824.0	531.4
26	2042	617.7	709.1	461.4	4354.1	9950.8	11309.4	1634.1	4834.1	530.9
27	2043	624.9	721.9	471.3	4361.2	9927.6	11333.1	1637.5	4844.2	528.9
28	2044	632.3	734.7	481.5	4369.2	9902.7	11356.8	1640.9	4854.3	527.9
29	2045	639.9	747.7	491.9	4377.4	9875.9	11380.5	1644.4	4864.4	528.4

Line No.	Year	Non-Manufacturing Employment (Thousands)	Educ & Health Employment (Thousands)	TTU[1] Employment (Thousands)	Financial Employment (Thousands)	Information Employment (Thousands)	Professional & Business Services Employment (Thousands)	Government Employment (Thousands)	Other Services Employment (Thousands)
30	2018	3797.8	685.99	791.59	221.0	56.0	659.4	609.0	166.0
31	2019	3816.8	690.60	796.72	225.8	55.5	655.7	615.8	167.3
32	2020	3482.5	636.52	741.66	224.2	50.2	596.4	576.0	142.1
33	2021	3614.8	652.22	782.76	232.7	52.8	633.2	573.9	155.1
34	2022	3759.8	662.97	805.95	231.6	56.6	658.5	591.4	162.9
35									
36	2023	3823.9	682.63	811.38	228.8	57.2	664.7	606.5	161.5
37	2024	3840.8	699.12	797.01	231.0	57.6	672.3	612.9	164.2
38	2025	3845.5	705.63	779.08	235.3	59.0	675.3	617.5	166.6
39	2026	3849.4	706.42	770.75	238.4	58.3	677.3	620.7	168.8
40	2027	3854.8	707.47	765.66	240.8	57.5	682.3	623.0	170.4
41	2028	3862.3	708.5	757.6	240.1	57.1	697.1	624.1	171.9
42	2029	3865.4	708.3	748.7	238.8	56.9	710.2	624.6	172.5
43	2030	3867.8	708.6	742.2	236.4	56.5	720.9	626.2	172.5
44	2031	3865.8	710.6	739.0	235.3	56.2	728.9	624.5	172.6
45	2032	3863.1	712.8	735.2	235.3	56.0	734.7	624.0	172.3
46	2033	3862.5	715.3	731.3	235.1	55.5	741.0	623.6	171.7
47	2034	3859.9	717.5	726.7	235.0	54.8	745.2	623.2	171.7
48	2035	3854.0	716.1	722.9	234.6	54.5	747.8	622.8	171.3
49	2036	3848.5	714.1	719.5	234.1	54.6	751.3	622.1	171.4
50	2037	3845.2	711.6	716.5	233.8	54.9	755.5	621.2	172.0
51	2038	3842.1	709.4	713.7	233.9	55.1	758.7	620.4	172.7
52	2039	3835.8	706.5	711.5	234.1	55.2	758.2	619.9	173.4
53	2040	3832.8	704.1	708.8	234.7	55.0	759.3	621.0	174.2
54	2041	3824.7	700.6	706.5	235.4	54.7	758.6	619.1	174.9
55	2042	3816.9	696.6	704.3	236.1	55.0	756.3	618.7	175.6
56	2043	3807.0	692.2	702.4	236.9	55.0	752.6	618.2	176.3
57	2044	3799.1	688.2	700.3	237.8	55.1	751.2	617.7	177.0
58	2045	3792.7	684.8	698.9	238.7	55.1	749.9	617.0	177.4

1) Transportation, trade & utilities

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Annual Customer Count
2018 -2023 Historical

Case No.: U-21662
Exhibit: A-32 pg. 1
Witness: E. C. Meloche
Page: 1 of 2

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Historical					
		2018	2019	2020	2021	2022	2023
1	SERVICE AREA						
2							
3	RESIDENTIAL	1,991,879	2,003,542	2,019,953	2,036,329	2,047,607	2,055,871
4							
5	SMALL C&I	204,955	205,744	206,701	208,957	210,158	210,829
6							
7	LARGE C&I	3,162	3,152	3,178	3,117	3,089	3,079
8							
9	STREET LIGHTING	1,068	1,057	1,058	1,056	1,049	1,044
10	PUMPING	0	0	0	0	0	0
11	WHOLESALE	0	0	0	0	0	0
12	TOTAL OTHER CLASS	1,068	1,057	1,058	1,056	1,049	1,044
13							
14	TOTAL	2,201,064	2,213,495	2,230,890	2,249,460	2,261,903	2,270,824
15							
16	ELECTRIC CHOICE						
17							
18	RESIDENTIAL	38	32	32	24	16	26
19							
20	SMALL C&I	3,840	3,730	3,658	3,755	3,729	3,587
21							
22	LARGE C&I	712	711	700	736	743	727
23							
24	STREET LIGHTING	0	0	0	0	0	0
25	PUMPING	0	0	0	0	0	0
26	WHOLESALE	0	0	0	0	0	0
27	TOTAL OTHER CLASS	0	0	0	0	0	0
28							
29	TOTAL	4,591	4,474	4,390	4,514	4,487	4,340
30							
31	BUNDLED						
32							
33	RESIDENTIAL	1,991,840	2,003,509	2,019,921	2,036,306	2,047,591	2,055,845
34							
35	SMALL C&I	201,115	202,014	203,043	205,203	206,429	207,242
36							
37	LARGE C&I	2,450	2,441	2,478	2,381	2,346	2,352
38							
39	STREET LIGHTING	1,068	1,057	1,058	1,056	1,049	1,044
40	PUMPING	0	0	0	0	0	0
41	WHOLESALE	0	0	0	0	0	0
42	TOTAL OTHER CLASS	1,068	1,057	1,058	1,056	1,049	1,044
43							
44	TOTAL	2,196,473	2,209,021	2,226,500	2,244,946	2,257,415	2,266,484

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Annual Customer Count
2024-2045 Forecast

Case No.: U-21662
Attachment: A-32 pg.2
Affiant: E. C. Meloche
Page: 2 of 2

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
		Forecast																					
		2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	SERVICE AREA																						
2																							
3	RESIDENTIAL	2,064,797	2,074,827	2,084,117	2,092,054	2,098,709	2,104,525	2,110,138	2,115,485	2,120,393	2,125,749	2,131,503	2,136,966	2,141,956	2,146,350	2,150,168	2,153,450	2,156,186	2,158,382	2,160,663	2,163,523	2,166,450	2,169,196
4																							
5	SMALL C&I	211,982	212,968	213,840	214,561	215,149	215,650	216,130	216,583	216,991	217,445	217,939	218,403	218,820	219,177	219,475	219,719	219,908	220,043	220,186	220,388	220,596	220,786
6																							
7	LARGE C&I	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075	3,075
8																							
9	STREET LIGHTING	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
10	PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	WHOLESALE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	TOTAL OTHER CLASS	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
13																							
14	TOTAL	2,280,897	2,291,913	2,302,075	2,310,733	2,317,976	2,324,292	2,330,385	2,336,185	2,341,502	2,347,311	2,353,560	2,359,487	2,364,894	2,369,644	2,373,761	2,377,287	2,380,212	2,382,542	2,384,967	2,388,029	2,391,164	2,394,100
15																							
16	ELECTRIC CHOICE																						
17																							
18	RESIDENTIAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19																							
20	SMALL C&I	3,470	3,383	3,295	3,208	3,121	3,033	2,946	2,859	2,771	2,684	2,597	2,509	2,422	2,335	2,247	2,160	2,073	1,985	1,898	1,811	1,723	1,636
21																							
22	LARGE C&I	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726	726
23																							
24	STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	WHOLESALE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	TOTAL OTHER CLASS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28																							
29	TOTAL	4,196	4,108	4,021	3,934	3,846	3,759	3,672	3,584	3,497	3,410	3,322	3,235	3,148	3,060	2,973	2,886	2,798	2,711	2,624	2,536	2,449	2,362
30																							
31	BUNDLED																						
32																							
33	RESIDENTIAL	2,064,797	2,074,827	2,084,117	2,092,054	2,098,709	2,104,525	2,110,138	2,115,485	2,120,393	2,125,749	2,131,503	2,136,966	2,141,956	2,146,350	2,150,168	2,153,450	2,156,186	2,158,382	2,160,663	2,163,523	2,166,450	2,169,196
34																							
35	SMALL C&I	208,512	209,586	210,545	211,354	212,028	212,617	213,184	213,724	214,220	214,761	215,342	215,894	216,398	216,842	217,228	217,559	217,836	218,058	218,288	218,577	218,873	219,150
36																							
37	LARGE C&I	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349	2,349
38																							
39	STREET LIGHTING	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
40	PUMPING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
41	WHOLESALE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
42	TOTAL OTHER CLASS	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043
43																							
44	TOTAL	2,276,701	2,287,804	2,298,054	2,306,800	2,314,129	2,320,533	2,326,714	2,332,600	2,338,005	2,343,901	2,350,237	2,356,252	2,361,746	2,366,584	2,370,787	2,374,401	2,377,413	2,379,831	2,382,343	2,385,492	2,388,715	2,391,738

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

EDDIE SMITH

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF EDDIE SMITH

Line No.

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

A1. My name is Carl E. Smith, "Eddie Smith" (he/him/his), Manager of Product Development and Residential Marketing for voluntary renewables at DTE Electric. My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from Ohio University in 2013 with a Bachelor of Arts (BA) degree in Sociology and in 2019 with a Master of Public Administration (MPA) degree. I am currently pursuing a Master of Business Administration (MBA) degree from the Ross School of Business at the University of Michigan.

Q4. What work experience do you have?

A4. I began my energy and utility career in 2016 managing a Community Choice Aggregation (CCA) program in Ohio known at the time as the Southeast Ohio Public Energy Council (SOPEC). SOPEC was established as a special purpose unit of local government that was authorized to manage opt-out governmental electric aggregation programming across multiple cities, villages, townships, and counties in the Southeast Ohio region. I joined SOPEC in 2016 as the Operations Coordinator and was later promoted to the role of Executive Director. In those roles, I was responsible for leading negotiations with alternative electric suppliers for

A5. program pricing, generation supply, and renewables content; overseeing the program's opt-out process; and leading the improvement of the program and its product's features, benefits, and user experience.

In 2019, I moved to Michigan where I began working for DTE Electric as a Sales Consultant selling the MIGreenPower program to DTE Electric's C&I customers. I remained a Sales Consultant until the COVID-19 work-from-home mandate began in Michigan, at which point I transitioned into a Strategist role on the voluntary renewables sales team and was later promoted to the role of Senior Strategist. In those roles, I was responsible for sales enablement, including training sales consultants on how various users could benefit from the product and how to discuss energy markets and credits, creating market and credit forecasts for sales consultants to share with prospects, segmenting customers in the market and identifying target segments, improving how leads are identified and qualified, aligning the customer relationship management (CRM) system with the sales process, and serving as a technical resource during sales meetings with large customers.

In 2022, I began working for Future Energy as the Director of Insight. Future Energy is a privately-owned company that provides consulting, project management, and vehicle charging software for clients exploring and implementing vehicle electrification. In this role, I was responsible for identifying client segments who would benefit from electrification incentives, training account executives on how various users could benefit from the product, coordinating with the company's Chief Strategy Officer to ensure that account executives complied with the consulting

program, identifying new product features and user experiences that would meet underserved client needs, and coordinating with the company's Chief Technology Officer and Chief Executive Officer on product strategy and product roadmap.

In 2023, I began working for Solutions for Energy Efficient Logistics (SEEL, LLC) as the Portfolio Director for DTE Electric's energy waste reduction (EWR) programming. SEEL is a privately-owned company that serves as an implementation contractor for energy efficiency programs for electric and gas utilities. In this role, I was responsible for overseeing the performance of the portfolio of DTE Electric's EWR programs that were being implemented by SEEL, including the Energy Efficiency Assistance (EEA) program, the Appliance Recycling Program (ARP), and the Energy Star Products marketplace program; aligning program designs and performance with DTE Electric's goals and identifying synergies where possible; and identifying key resource and capability needs across the portfolio for strategic investment.

I returned to DTE Electric in 2023 as the Manager of Product Development and Residential Marketing for voluntary renewables. In this role, I lead a team of product managers and residential marketing professionals for the MIGreenPower program.

In addition to these roles, I am a member of the international Association of Energy Engineers (AEE), a member of the East Michigan Chapter of the Association of Energy Engineers (AEE), and a member of the Midwest Renewable Energy Association (MREA). I am also a Certified Energy Manager (CEM), Certified Energy Auditor (CEA), and Renewable Energy Professional (REP) through the

Association of Energy Engineers (AEE). I also completed four in-person training events on Market Optimization, Power System Elements, Locational Marginal Pricing, and FTR/ARR Markets through the PJM training department. Additionally, I completed the 45th Eastern NARUC Public Utility Rate School, the 39th Grid School, and 14th Advanced Regulatory Studies Conference through the Institute for Public Utilities (IPU) at Michigan State University. I also completed the Product Management Program through the Center for Professional Development at Stanford University.

Q5. What is your current position and associated responsibilities?

A6. I currently serve as the Manager of Product Development and Residential Marketing for voluntary renewables at DTE Electric. In this role, I lead a team of product managers, solution architects, and residential sales professionals for the MIGreenPower program, and my team is responsible for identifying, developing, and bringing new products to market that advance DTE Electric's product strategy as well as planning and implementing a go-to-market strategy for acquiring residential subscribers.

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

A7. No. I have not previously sponsored testimony.

Q7. What is the purpose of your testimony?

A8. The purpose of my testimony is to provide details on key topics regarding DTE Electric's MIGPreenPower program in support of the Company's request for Commission approval on such topics. I will be providing testimony regarding:

1) The MIGreenPower Demand forecast;
2) The Company's request to increase the build plan for the MIGreenPower program;
3) The status of Community Solar and Solar For All;
4) The purchase of Renewable Energy Credits from Distributed Generation customers; and
5) The structure and terms of Special Contracts.

Q8. Are you sponsoring any exhibits in this proceeding?

A9. Yes. I am sponsoring the following exhibit(s):

Exhibit	Description
A-33	MIGreenPower Demand Forecast

Q9. Were these exhibit(s) prepared by you or under your direction?

A10. Yes, they were.

Q10. How is your testimony organized?

A11. My testimony consists of the following sections, which align with the aforementioned purpose.

Part I. Overview of the MIGreenPower Demand forecast

Part II. Request for approval to increase the build plan to support MIGreenPower

Part III. Community Solar and Solar for All

Part IV. Purchase of RECs from Distributed Generation Customers

Part V. MIGreenPower Special Contracts

PART I. OVERVIEW OF MIGREENPOWER DEMAND FORECAST

Q11. What is the forecasted sales demand for the MIGreenPower program?

A12. The forecasted sales demand for MIGreenPower is shown in Exhibit A-33 and is divided into three sections: 1) non-contract traditional, 2) contracted traditional, and 3) customer-requested. The non-contracted forecast covers customers subscribing less than 2,500 MWh, the contracted forecast is covers traditional MIGreenPower customers subscribing at least 2,500 MWh, and the customer requested covers all Special Contracts.

Q12. How did the Company establish the MIGreenPower forecast?

A13. 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 customer enrollment rates were based on historical customer acquisition rates. For contracted customers, the Company forecasted future enrollment levels by considering estimates of future loads and established enrollment levels for currently contracted customers, as well as any large customers the Company is currently in discussions with to enroll in the traditional MIGreenPower program or design and construct dedicated projects under a Special Contract.

Q13. Based on the subscription forecast that was provided in Exhibit A-33, does the Company believe there is enough renewable energy generation to support the future enrollments for MIGreenpower program?

A14. No. The Company believes the current portfolio of MIGreenPower projects is not adequate to support the program based on the forecasted demand.

PART II. REQUEST APPROVAL TO INCREASE THE MIGREENPOWER BUILD PLAN

Q14. How does the Company plan to meet the continued demand for the program?

A15. Due to the popularity of the MIGreenPower program, the program is fully subscribed as reported in the April 2024 semi-annual voluntary green pricing (VGP) report filed in Case No. U-18352. To meet demand for the program, the Company is pursuing both a short-term (through 2026) and long-term strategy (2027 and beyond). In the short-term, the Company is coordinating with large customers to see if any are willing to temporarily curtail their own subscriptions during years when there is insufficient generation so fulfill all subscriptions. Additionally, the Company will offer market-based renewable energy credits (RECs) through the REC-Only Option as approved in Case No. U-21172.

In the long-term, the Company is requesting approval to add an additional 930 MW to the MIGreenPower build plan; 300 MW in 2027, 500 MW in 2028, and 130 MW in 2029.

PART III. COMMUNITY SOLAR AND SOLAR FOR ALL

Q15. What is Solar for All?

A16. In June 2023, the U.S. Environmental Protection Agency (EPA) released a $7 billion Solar for All Funding opportunity to expand access to renewable energy. In April 2024, the State of Michigan was awarded $156 million for the MI Solar for All program[1] to support solar development for thousands of households in low-income and disadvantaged communities across Michigan through direct financial assistance for rooftop solar, community solar, and energy storage.

Q16. Will the Company pursue funding through Solar for All?

A17. Yes. The Company has identified two of its low-income solar pilots, Community Impact and Community Support, as possible programs that could be supported through Solar for All funding. The Company is monitoring the Department of Environment, Great Lakes, and Energy's (EGLE) Solar for All websites for updates and plans to apply for funding once applications are available, expected late 2025.

Q17. What will the funding be used towards?

A18. If chosen as a recipient by EGLE, the Company will use the funds to support two of the MIGreenPower low-income pilots. The Company's low-income pilots are focused in two areas: 1) Community Support: which allows DTE customers to make voluntary contributions to support MIGreenPower subscriptions for low-income subscribers, and 2) Community Impact: which develops community solar parks in the southeastern Michigan communities of Detroit, River Rouge, and

[1] MI Solar for All (michigan.gov)

Highland Park, and provides free subscriptions to those parks to low-income subscribers living in those communities.

Q18. Where will this matter be discussed?

A19. Updates on the low-income pilots and grant and funding opportunities will be discussed in the Company's next VGP program case planned for September 2024.

PART IV. PURCHASE OF RECS FROM DISTRIBUTED GENERATION CUSTOMERS

Q19. Is the Company evaluating the purchase of renewable energy credits (RECs) from Distributed Generation (DG) customers?

A20. Yes, as ordered in Case No. U-21172, the Company held an outreach session on June 20, 2024, with stakeholders regarding the purchase of RECs from DG customers and plans to include a proposal that comports with PA 235 in the next VGP program case, Case No. U-21375.

Q20. Where will this matter be discussed?

A21. As ordered in Case No. U-21172, a proposal for the purchase of RECs from DG customers will be discussed in the Company's next VGP program case planned for September 2024.

PART V. MIGREENPOWER SPECIAL CONTRACTS

Q21. What is the background of the Company's Special Contracts as it relates to MIGreenPower?

A22. The Company submitted within its VGP program, Case No. U-20713, application an offering for one-of-a-kind projects with unique design criteria based on customer input that do not fit within the Rider 17 and Rider 19 offerings, collectively now known as Rider 17. Through the customer-requested offering, the Company is ultimately selected to design and construct dedicated solar projects that support each respective customer's sustainability aspirations. Customers participating in this offering are required to subscribe to the output of the project(s) for the life of the project. The cost and credit structure of these projects align with Rider 17 methodology for determining the levelized cost of energy (LCOE) and the market-based credits. The Partial Settlement Agreement approved by the Commission in Case Nos. U-20713 & U-20851 details the approval to include a Customer-Requested offering in its VGP program and further includes terms to which it is to adhere.

Q22. How many customers are currently under a Special Contract?

A23. There are currently two large customers that have signed Special Contracts which were submitted to the Commission for review and approval in the Case No. U-21285 Amended REP filing and the Case No. U-21361 2023 Amended REP filing. Both Special Contracts were approved by the Commission and used the structure described in questions 23 through 25 below.

Q23. How are subscription fees determined for Special Contracts?

A24. As explained in Case No. U-20713 in Witness Calka's testimony on page 23 line No. 22 through 25, "When a DTE Electric customer proposes a project, the Company will consider the size and scope of the requested project(s) as well as the

ability and willingness of the requesting customer to subscribe to the project(s) for the life of the project(s)." Each Special Contract has the same cost-based fee and credit structure as Rider 17. For example, the Company utilizes the same LCOE model that is used for Company-owned assets, which estimates the levelized life-cycle cost per MWh of generation. The model uses the projected $/kW installed costs, net capacity factor, as well as proprietary assumptions that reflect the ongoing life-cycle costs such as financing, O&M, capital maintenance, taxes and insurance, on a net present value basis in order to determine the LCOE for a project. Furthermore, each project's costs will be allocated to the participating customer(s) for the life of the project, the costs and accounting will be transparent, and the projects' RECs will not be used for PA 342 compliance purposes. The Special Contract offering costs are structured and approved as a levelized subscription fee and corresponding credit that is reflective of the benefits of the project as described in the Partial Settlement Agreement, Section 9.1.3.4.1, approved via the Order in Case Nos. U-20173 & U-20851. Additionally, as detailed in the Partial Settlement Agreement Section 9.1.3.1 approved in Case Nos. U-20173 & U-20851, the Company is to bring Special Contracts for approval before the Commission on an ex parte basis along with ex parte amendment of the REP to add the contracts.

Q24. Are there any termination or default provisions?

A25. Yes, the Company details termination and default provisions within the Special Contract. The termination fee is equal to one year's subscription fees plus the cost of utilizing a levelized subscription fee. The default fee is equal to the remaining value of the agreement. Either fee may be waived if the Company determines there is an alternate need for the project, such as fulfilling additional customer demand.

The contract is structured so that it mitigates financial risk to the Company and its customers, including termination fees and standard protections including, for instance, liquidated damages provisions. If the customer elects to not pay the termination fee and thus breaches the contract, the Company will take all necessary legal actions required to recover its costs from the breaching party, as it would do with any breach of commercial contract. The Company would also seek to mitigate its damages by determining if there is an alternate need for the project, such as another special contract request, or whether sale of the asset would be possible.

Q25. Do Special Contracts require subscribers to pay for all of the associated costs from the renewable energy projects that supply their Special Contracts?

A26. Yes. All costs associated with the development of the renewable energy project(s) to supply Special Contracts are fully recovered through the subscription fees that are featured in the Special Contracts and are billed to the subscriber. Any early termination or default of the contract from the subscriber's actions or inactions results in a termination fee, designed so that all costs are ultimately bore by subscribers and that no costs are subsidized by non-subscribers.

Q26. Does this complete your direct testimony?

A27. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

EDDIE SMITH

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
MIGreenPower Demand Forecast
2024-2044 Forecast

Case No.: U-21662
Exhibit: A-33
Witness: E. Smith
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
													Annual Demand Forecast - GWh										
Line No.		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
1	Non-Contracted	265	320	375	430	485	540	540	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
2	Contracted	1,890	2,335	3,058	3,121	3,654	3,975	3,975	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600
3	Customer-Requested	-	-	762	1,794	2,552	2,542	2,542	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523	2,523
4	Total	2,155	2,655	4,195	5,345	6,690	7,057	7,057	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773
		2,155	2,655	4,195	5,345	6,690	7,057	7,057	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773	7,773
	Ren Sol WP	1,315.35	1,972.14	2,794.62	5,358.09	6,616.22	7,426.91	7,415.00	7,385.97	7,375.76	7,328.31	7,299.69	7,271.20	7,261.22	7,214.63	7,186.54	7,158.58	7,148.81	7,103.05	7,075.48	7,048.05	7,038.50	6,993.56
		(840.13)	(682.39)	(1,399.89)	12.90	(73.87)	369.60	357.69	(386.59)	(396.80)	(444.25)	(472.87)	(501.36)	(511.34)	(557.94)	(586.03)	(613.99)	(623.75)	(669.51)	(697.08)	(724.52)	(734.06)	(779.00)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

NATHAN D. BENNETT

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

A1. My name is Nathan D. Bennett (he/him/his). My business address is One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company.

Q2. On whose behalf are you testifying?

A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q3. What is your educational background?

A3. I graduated from the University of Michigan in 2009 with a Bachelor of Science in Nuclear Engineering and Radiological Sciences. In 2011, I received a Master of Engineering Degree in Energy Systems Engineering from the University of Michigan.

Q4. What work experience do you have?

A4. I began my professional career in 2011 as a nuclear engineer with Bechtel Power Corporation where I supported the design of small modular nuclear reactors and later the construction of a large U.S. nuclear power station. In 2013, I joined MCR Performance Solutions, a boutique management consultancy to the utility industry. There I supported nuclear utility clients in optimizing capital and O&M budgets to reduce cost while improving safety and reliability performance, rising to the role of Lead Consultant during my time with the firm. In 2016, I joined DTE Energy as a Senior Business Analyst in the Corporate Strategy team. I spent the next four years supporting a broad range of strategic projects, primarily focused on DTE Electric, rising to the role of Senior Associate. In 2020, I transitioned to a Strategy and Project Specialist role in DTE Electric's Wholesale Power Market Development

team. There I was responsible for representing DTE Electric in the Midcontinent Independent System Operator (MISO) stakeholder process, with a focus on market, resource adequacy, and distributed energy resource policies. In 2021, I transitioned to DTE Energy's Regulatory Affairs team as a Regulatory Strategy Consultant and was later promoted to Manager, Regulatory Affairs, supporting the Company's state regulatory strategy and engagement with the Michigan Public Service Commission (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2024, I transitioned to my current position of Manager, Clean Energy & Acquisitions within DTE Electric.

Q5. What are your current duties and responsibilities?

A5. My current responsibilities include the development of Company strategies related to energy storage and other clean energy technologies as well as the financial evaluation of those technologies.

Q6. Have you previously sponsored testimony before the Michigan Public Service Commission?

A6. No, I have not.

Purpose of Testimony

Q7. What is the purpose of your testimony?

A7. The purpose of my testimony is to:

- Support the Company's plans to deploy energy storage co-located with Company renewable facilities,

- Support the Company's request to recover its cost-share for a long duration energy storage (LDES) demonstration project at the Pine River wind park and solar array, which will be partially funded through a Department of Energy (DOE) grant under the Infrastructure Investment and Jobs Act (IIJA), and
- Propose a framework for recovering the costs of both Company-owned and third-party-owned storage co-located with renewable facilities, including the Company's share of the Pine River LDES demonstration project.

Q8. Are you sponsoring any exhibits in this proceeding?

A8. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-34	Illustrative REP impact from Pine River long duration energy storage demonstration project
A-35	MPSC Pilot Objective Criteria for Pine River long duration energy storage demonstration project

Overview of energy storage co-located with renewables

Q9. What benefits does energy storage provide?

A9. Energy storage can provide a range of services to the bulk electric system. These include the ability to serve as a capacity resource, provide ancillary services, and engage in energy arbitrage by charging during hours when MISO locational marginal prices (LMPs) are lower and discharging during hours when LMPs are higher. Energy storage may also provide other benefits, although these are typically location-specific.

Q10. What additional benefits can energy storage provide when co-located with existing renewables?

A10. Co-locating energy storage with existing renewables can provide additional benefits beyond the core bulk electric system benefits described above. These benefits may include:

- **Reduced development and installation costs:** Since the storage resource is utilizing an existing site, the Company and its customers may realize lower development and installation costs relative to a greenfield standalone site. For example, a storage project co-located with an existing site could leverage existing site infrastructure, such as transformers and substation equipment, as well as land and easements that are already under the control of the site owner.
- **Increased utilization of existing interconnection:** Co-locating energy storage with existing renewables may allow the Company to take advantage of an existing interconnection, avoiding the potential for costly transmission system upgrades that may be needed to interconnect a greenfield standalone site. The Midcontinent Independent System Operator surplus interconnection process also allows for new resources to be added to an existing interconnection and is much faster than the queue for a new interconnection, thus co-location avoids the need for the lengthier process.
- **Capture of otherwise curtailed energy from renewable facilities:** Curtailment is the reduction of a renewable facility energy generation output below what it would be otherwise be capable of, with a given wind speed or solar irradiance. Co-locating energy storage with existing renewables may

allow the Company to store some or all energy that would otherwise be lost due to curtailment of the renewable facility.

- **Capture of otherwise clipped energy from solar facilities:** Solar clipping occurs when solar panels provide more power than an inverter can manage. Co-locating energy storage with solar facilities may allow the Company to store clipped energy produced behind the solar farm's inverter in excess of the inverter's maximum rated capacity, which would otherwise be lost but for the ability to store it.

Q11. Why is renewable generation curtailed?

A11. The output of a renewable energy facility can be curtailed for a variety of reasons including:

- **Output greater than what is allowed by the Generator Interconnection Agreement (GIA):** The facility's GIA imposes a maximum amount of power that can be injected into the transmission system. If output from the facility exceeds what is allowed by the GIA, the Company must curtail that output to comply with the GIA.
- **Transmission network outages:** Outages on the transmission network are occasionally necessary to facilitate repair of existing network infrastructure or construction of new network infrastructure. This can impose limitations which are incremental to those in a facility's GIA, resulting in incremental curtailment.
- **Economic and reliability curtailments:** When LMPs at a renewable facility's pricing node are less than the marginal cost of the facility's energy

or when directed to by MISO for grid reliability, continuing to inject energy into the transmission system can incur additional costs and/or jeopardize the reliability of the grid. Therefore, it is necessary to curtail production during these times.

Q12. Why is solar generation clipped?

A12. For many solar farms, it is beneficial to overbuild the facility by installing panel capacity in excess of the inverter's rated power output. For example, a solar farm with 50 MW of rated inverter output (alternating current basis) may be overbuilt to have 60 MW of installed panel capacity (direct current basis). This allows the solar farm to maintain its maximum output as panel performance degrades over time and provides more output to the grid when there is sufficient solar irradiance and output is below the maximum rated output, potentially enhancing the farm's capacity value. However, absent any storage behind the inverter, any panel energy output in excess of the inverter's rated output is lost.

Q13. How does the capture of curtailment and/or solar clipping benefit customers?

A13. Storing energy which would otherwise be curtailed or clipped allows the Company to store energy that would otherwise be lost and use it during the most optimal times, providing an economic benefit to our customers. This also allows for the Company to generate renewable energy credits (RECs) and incentive RECs (IRECs) associated with storing the renewable energy, as prescribed by MCL 460.1039(2)(c), from the otherwise lost curtailment or clipped energy. These RECs and IRECs can be used to meet the 2023 PA 235 renewable energy requirements.

Q14. Has the Company quantified the potential benefits of co-locating energy storage with renewables?

A14. No. The cost savings of reduced development and installation costs and utilizing an existing interconnection is very site specific and will vary greatly by site. In order to quantify these savings, the Company would need to know the cost of any potential network upgrades associated with obtaining a new interconnection for a greenfield storage site that the Company would incur but for the ability to deploy storage at an existing interconnection.

Additionally, quantifying the potential benefits of curtailment capture is subject to significant uncertainty. While transmission investments are occurring across the MISO system, it is difficult to forecast when outages on certain parts of the system will take place and how they will affect the Company's renewable facilities. While increasing deployment of renewables on the transmission system may lead to increased prevalence of negative LMPs, the specific frequency of these occurrences is also difficult to forecast. Finally, quantifying the potential benefits of avoided solar clipping will depend on the site where the storage is to be located.

Q15. Absent a quantification of potential benefits, why is it beneficial to co-locate energy storage with existing renewable facilities?

A15. Co-locating energy storage with existing renewable facilities provides the Company's customers with a hedge against the risk of incurring certain costs as well as the risk of forgoing certain benefits. By utilizing an existing interconnection, the Company's customers avoid the potential cost of transmission upgrades to serve a new storage facility. By co-locating storage with existing

renewable facilities, the Company's customers avoid the potential for future curtailment and clipping and reap the benefits of increased output from the renewable facilities in the form of energy benefits, RECs, and IRECs. While the exact quantification of these benefits is difficult to estimate without detailed planning at a particular site, the potential to mitigate these risks is clear. All other factors being equal, if these risks do materialize, customers will be better off with co-located storage rather than greenfield standalone storage.

Q16. Does the Company have any plans to further explore and/or quantify these benefits?

A16. Yes. The Company intends to further explore and potentially quantify some of these benefits through the Pine River long duration energy storage (LDES) demonstration project, which I describe further in the next section of my testimony.

Pine River LDES demonstration project and DOE grant

Q17. Can you describe the Pine River LDES demonstration project?

A17. The Company has partnered with the Electric Power Research Institute (EPRI), Our Next Energy (ONE, a Michigan-based manufacturer of electric vehicle batteries), and Michigan Technological University (MTU) to pursue a grant from the DOE to support the demonstration of LDES. The grant would demonstrate the hybridization of wind and solar with a 10-hour, 1.4 MW (14 MWh) Lithium-Iron-Phosphate battery. The Company and its partners proposed the Pine River Wind Park as the site for this demonstration given that it would provide an opportunity to hybridize the storage facility with the currently operating 161 MW wind park and the future 80 MW solar array. The Company and its partners further proposed

utilizing second life electric vehicle batteries (SLBs) for augmentation as the performance of the initial installation degrades over time.

Q18. Why is it important to test LDES through this demonstration project?

A18. The Company, its partners, and the DOE recognize that LDES will play an important role in the nation's generation portfolio. This will be particularly important as the Company transitions toward net zero carbon emissions, while maintaining reliability and affordability. This demonstration project provides an opportunity to test the integration of LDES and renewables in firming variable renewable resources, ultimately supporting the Company's advancement toward net zero.

Q19. Why is it important to test the use of SLBs through this demonstration project?

A19. As the nation's vehicle fleet becomes increasingly electrified, the supply of EV batteries which have reached their end-of-life will also increase. However, these batteries can be repurposed to provide grid services. This demonstration project aims to utilize SLBs to "augment" the Pine River battery's storage capacity over time. Augmentation refers to the addition of more battery packs to maintain an energy storage facility's rated capacity as the performance of the older packs degrades. Utilizing SLBs avoids the need to manufacture new battery packs to support augmentation, diversifying the supply base, avoiding the environmental impacts of newly manufactured packs, and potentially resulting in lower costs.

Q20. What efforts have the Company and its partners undertaken to date to obtain funding for this demonstration project?

A20. On September 15, 2023, the Company submitted a concept paper to the DOE for a $5 million grant. On October 16, 2023, the DOE encouraged the Company's concept paper, and the Company submitted a full application on December 4, 2023.

Q21. What is the current status of the Company's grant application?

A21. On May 15, 2024, the DOE notified the Company that it had recommended the Company's application for negotiation of a financial award. While this notification does not guarantee Federal Government funding, it is an important milestone for the Company's and its partners' efforts as funding will be awarded upon successful completion of negotiations.

Q22. What is the total cost reflected in the Company's grant application?

A22. The total cost reflected in the Company's grant application is $10.1 million.

Q23. What is the Company's cost-share reflected in its grant application?

A23. The Company's cost-share reflected in its grant application is $5,114,175.

Q24. When will the Pine River LDES demonstration project enter commercial operation?

A24. The exact timing of commercial operation is uncertain as the timing for starting the project will depend on how award negotiations with the DOE proceed. However, the Company's application has proposed that construction would commence in the fourth quarter of 2025 and that commissioning would commence in the second quarter of 2026.

Q25. Will there be any activities related to the demonstration project after it enters commercial operation?

A25. Yes, for a period of two years, the system will undergo an independent evaluation by EPRI and MTU to assess system performance, including augmentation of the system with SLBs in year two.

Q26. How does the Company propose to recover the costs for its share of this demonstration project?

A26. In the event that the Company and the DOE are able to successfully negotiate an award, the Company proposes to recover the costs for its share of this demonstration project through the Renewable Energy Plan (REP) using the cost recovery framework I describe later in my testimony. In a subsequent Amended REP filing and reconciliation following the project's commercial operation date, the Company would include the costs of the project for recovery.

Q27. Why is the Company proposing to recover this cost through the REP?

A27. As I describe later in my testimony, energy storage co-located with renewables fits within the statutory definition of a "renewable energy system" and thus it is appropriate to recover its cost through the REP. Energy storage also ensures the reliability and quality of the renewable energy used to meet the Renewable Portfolio Standard.

Q28. Are there any secondary reasons the Company is proposing to recover this cost through the REP?

A28. Yes, projects selected by the DOE for funding are subject to a periodic project evaluation referred to as a "Go/No-Go Review." Go/No-Go decision points are included to demonstrate meaningful and measurable technical progress and provide justification for the continuance of the project. Based on the results of the Go/No-Go review, the DOE may elect to continue, redirect, place a hold on, or discontinue funding.

Obtaining favorable regulatory support in 2025 is a Go/No-Go decision point for the Pine River LDES demonstration project. In other words, if the Company is unable to obtain favorable regulatory support by year-end 2025, it is at risk of losing any funding it may have been awarded as part of this funding opportunity. Given that the Company has already filed a general electric rate case on March 28th of this year, the soonest it could file another rate case would be March 28th of 2025. Given the 10-month timeline for adjudicating a rate case, this would make receiving a rate case order in 2025 unlikely.

Q29. What would be the impact on the REP if the Company is awarded this grant?

A29. Exhibit A-34 provides an estimate of the impact to the REP if the Company is awarded this grant and the cost is recovered through the REP. Lines 1 through 7 provide key assumptions for estimating the project's impact on the REP. Line 14 provides an estimate of the incentive RECs that would be generated. Line 15 provides an estimate of the revenue requirement. Line 17 provides an estimate of the amount recovered through the PSCR. Line 18 provides an estimate of the incremental cost of compliance.

Q30. What would be the impact on the REP if the Company is not awarded a grant?

A30. In the event that the DOE does not award grant funding, the Company's intent is to abandon the project, and there would be no impact to the REP.

Q31. Does this demonstration project meet the Commission's definition of a pilot?

A31. Yes, it does. The February 4, 2021, Order in Case No. U-20645 established the following definition of a pilot: "A pilot is a limited duration experiment or program to determine the impact of a measure, integrated solution, or new business relationship on one or more outcomes of interest." This demonstration project, with its focus on testing LDES and SLBs complies with the Commission's definition of a pilot.

Q32. What additional requirements from the Commission apply to proposals meeting the Commission's pilot definition?

A32. The February 4, 2021, Order in Case No. U-20645 also established six objective criteria for utility pilots and found that all proposals meeting the Commission's pilot definition shall include these objective criteria for evaluation by the Commission. These objective criteria are reflected in Exhibit A-35.

Overview of the Company's plans and proposed cost recovery framework

Q33. Where does the Company intend to deploy co-located energy storage?

A33. In addition to the Pine River LDES demonstration project, the Company is considering its existing and near term-renewable facilities as potential candidate sites for co-located storage. This would potentially allow the Company to realize the benefits associated with reduced installation costs as well as utilization of an

existing interconnection and the other benefits described previously in my testimony. The Company is particularly focused on sites where wind and solar share a single point of interconnection given that the potential for GIA-based curtailment may be higher.

Q34. Does the Company plan to allow third parties to bid co-located renewable and storage projects?

A34. Yes. While the 2024 RFPs for Renewable Energy and Energy Storage were each for standalone projects[1], going forward the Company intends to solicit renewables, energy storage or co-located projects in future RFPs in part due to the benefits noted above.

Q35. When does the Company intend to deploy co-located energy storage?

A35. In addition to the Pine River LDES demonstration project, the Company may consider deployment of co-located energy storage with a commercial operation date of 2028 as part of the 275 MW of Company-owned IRP settlement energy storage allocations.

Q36. What does Michigan's energy law say with regard to recovering the costs of co-located energy storage through the REP?

A36. Michigan's energy law does not explicitly state whether the costs of co-located energy storage can be recovered through the REP. However, MCL 460.1011(i) defines "Renewable energy system" as "a facility, electricity generation system, or set of electricity generation systems that use 1 or more renewable energy resources

[1] The 2024 RFP will also allow for co-located storage at existing renewable sites where DTE-Electric is the market participant

to generate electricity or steam"[2]. MCL 460.1011(g) defines "Renewable energy resource" to include wind power and solar power.

Q37. Does energy storage co-located with renewables meet the definition of "Renewable energy system" in MCL 460.1011(i)?

A37. I am not an attorney; however, my lay interpretation is that co-located energy storage would "use 1 or more renewable energy resources to generate electricity," thus complying with the definition in the statute. More specifically, the energy storage would charge from the renewable energy facility whenever it is capturing otherwise curtailed or clipped energy. Additionally, during times when the renewable energy facility is generating and the co-located energy storage is charging, the co-located energy storage would effectively charge from the renewable energy facility given that they are at the same point of interconnection.

Q38. Are there other reasons that it is appropriate to recover the cost of co-located energy storage through the REP?

A38. Yes. In calculating the incremental cost of compliance under MCL 460.1047, the Company may include "any additional electric provider costs determined by the commission to be necessarily incurred to ensure the quality and reliability of renewable energy used to meet the renewable energy standards." As stated above, co-located energy storage will enhance the output of the Company's renewable facilities, producing both RECs and IRECs. Including investments in co-located energy storage through the REP will allow Staff, stakeholders, and the Commission to holistically consider the Company's investments within one proceeding,

[2] The definition in MCL 460.1011(i) goes on to exclude certain hydroelectric resources and incinerators from this definition.

providing a more complete view of the resources the Company is utilizing to meet the renewable energy and clean energy standard goals outlined in PA 235 of 2023 and allowing for approval of those resources within a single filing. Separating the costs of co-located energy storage to be recovered in a separate proceeding would be unnecessarily cumbersome, as it may require splitting a single project into two parts for evaluation in separate regulatory filings, which would complicate project financing, approval, and construction timelines for both utility-owned and non-utility-owned projects. A streamlined proceeding ensuring a more coordinated and timely path to construction and commissioning is imperative to fulfilling the requirements established in PA235 of 2023.

Q39. How does the Company propose recovering the cost of the co-located energy storage resource?

A39. The Company proposes that LMP-based charging costs and discharging benefits for co-located storage would flow through the Power Supply Cost Recovery (PSCR) mechanism as purchases and sales of energy. The Company further proposes that the levelized cost of the revenue requirement for the fixed costs of the co-located storage resource be recovered through the REP transfer price mechanism.

Q40. How does the Company propose to calculate the levelized cost for co-located energy storage?

A40. The Company's preferred approach to establishing a transfer price for co-located energy storage would be to use a capacity-based transfer price rather than an energy-based transfer price like those used in the REP today. A capacity-based

transfer price aligns with how the Company intends to contract for third party energy storage resources in the future (i.e., through tolling agreements with prices established in $/kW-month). However, the language in MCL 460.1047(2)(b)(iv) specifies that the transfer price be established as a "price per megawatt hour".

In order to align the cost of the co-located energy storage with the existing transfer price framework, the Company proposes that the fixed cost of the energy storage resource be levelized over the available energy (in megawatt hours) over the life of the project. The available energy is defined as the battery's maximum discharge capacity (in megawatts) multiplied by the number of hours that the battery is available. For a representative 100 MW battery with 95% availability over the course of a calendar year, the available energy would be equal to 100 MW multiplied by the 95% availability multiplied by the hours in the year.

Q41. What does the Company estimate for the levelized cost for co-located storage at the Pine River long duration energy storage demonstration project?

A41. The Company estimates that the levelized cost for co-located storage at the Pine River long duration energy storage demonstration project would be $24.05 per MWh available. This accounts for the Company's cost share and the energy storage Investment Tax Credit (ITC). The project is expected to qualify for the ITC's energy community adder, resulting in a total ITC of 40%, which is reflected in the Company's estimate of the levelized cost. If the project is deemed eligible for the ITC's domestic content adder, then the total ITC would increase to 50%. The ITC is assumed to be transferred to a third party at a 5% discount, which will reduce the Incremental Cost of Compliance in the year generated.

Recommendations for the instant case

Q42. What is your request to the Commission in the instant case?

A42. Given the benefits of co-located storage, the Company is requesting that the Commission approve the conceptual plan to co-locate energy storage with renewables and recover the fixed cost of the storage resource through the REP transfer price mechanism. Further, the Company is requesting that the Commission approve the inclusion of costs for the Pine River long duration energy storage demonstration project, conditional on the Company's successful negotiation of an award from the DOE. Although the levelized cost of the Pine River demonstration project is below the transfer price and would be collected through the PSCR, in the event that the levelized cost of a future storage project exceeds the transfer price, the Company would propose that recovery through the PSCR be capped at the transfer price.

Q43. Does this complete your direct testimony?

A43. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE ELECTRIC COMPANY to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

EXHIBITS

NATHAN D. BENNETT

Michigan Public Service Commission
DTE Electric Company
2024 Amended REP
Illustrative REP Impact from Pine River LDES Demonstration Project

U-21662
A-34
N. Bennett
1 of 1

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	Maximum Discharge Capacity (MW)	1.4																						
2	Discharge Duration (hours)	10																						
3	Maximum Energy Storage (MWh, line 1 * line 2)	14																						
4	System Availability (%)	97%																						
5	Roundtrip Efficiency (%)	89%																						
6	Annual Degradation (%)	2.4%																						
7	Levelized Cost of Available Energy ($/MWh)	$24.05																						
8																								
9		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
10																								
11	Available Energy (MWh, line 1 * line 4 * 8760)				11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896	11,896
12	Energy Discharged (MWh, line 3 * line 4 * 365 days less degradation starting in 2029)				4,957	4,957	4,838	4,722	4,608	4,498	4,390	4,284	4,182	4,081	3,983	3,888	3,794	3,703	3,614	3,528	3,443	3,360	3,280	3,201
13	Energy Charged (MWh, line 12 / line 5)				5,569	5,569	5,436	5,305	5,178	5,054	4,932	4,814	4,698	4,586	4,476	4,368	4,263	4,161	4,061	3,964	3,869	3,776	3,685	3,597
14	Incentive RECs Generated (line 13 / 5)				1,114	1,114	1,087	1,061	1,036	1,011	986	963	940	917	895	874	853	832	812	793	774	755	737	719
15	Revenue Requirement				(2,525,312)	845,281	790,153	735,434	686,064	643,176	611,503	586,341	560,648	536,895	512,217	488,484	464,761	441,984	415,478	245,360	71,724	54,399	51,805	52,411
16	Forecasted Transfer Price per Available MWh (line 7)				$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05	$24.05
17	Amount Recovered Through the PSCR (line 11 * line 16)				286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101	286,101
18	Incremental Cost of Compliance (line 15 - line 17)				(2,811,413)	559,180	504,052	449,333	399,963	357,075	325,402	300,241	274,548	250,795	226,116	202,383	178,661	155,884	129,377	(40,741)	(214,377)	(231,702)	(234,296)	(233,690)

DTE Pilot Informational Document

Project Name: **Pine River Long Duration Energy Storage (LDES) Demonstration Project**
Included with Case: **Case No. U-21662**
Sponsoring Witness: **Nathan Bennett**

(1) Pilot need and goals	

a. Need for the pilot is expressed. Results of similar pilots and findings are shared to justify the need for the proposed pilot.	• Longer duration storage technologies will become more important as more renewables are added to the grid over the next decade.
	• LDES will offer greater flexibility in providing reliable power supply over longer periods of time as renewable penetration on the grid increases.
	• Co-located LDES can also further enhance the value of renewables:
	  ○ Renewable generation is curtailed for many reasons including higher output than GIA maximum, transmission network outages and economic or reliability curtailments.
	  ○ This excess generation provides an opportunity for energy storage to play a complementary role.
	• Furthermore, the combination of wind, solar, and storage will result in a more uniform generation curve, bridging two, four, and six-hour peaks and troughs.
	• The Pine River LDES demonstration is a unique project as there are only five plants in the United States that have storage co-located or hybridized with both wind and solar generation assets, and the average storage duration for these existing plants is only 2 hours.
	• Additionally, second life electric vehicle batteries (SLBs) are a potential source of battery packs for augmenting utility-scale energy storage over time.
	• There are only two companies worldwide that are UL (United Laboratories) certified for repurposing batteries into second life applications, neither of which are U.S. companies. Novi-based project partner Our Next Energy plans to become the first U.S. company to become UL-certified under this project, closing a critical circularity gap between first-life EV battery deployment and battery recycling and strengthening the U.S. battery supply chain.

b. Pilot goals and desired learnings are detailed.	Pilot Goals: • The installation of a 1.4 MW energy storage system, hybridizing a Li-Ion LDES battery with wind and solar resources • Perform augmentation with SLBs Desired Learnings: • Test the integration of long duration storage and renewables in firming variable renewable resources • Test the use of SLBs for augmentation • Validate performance characteristics of long duration storage
c. Reference any pending applicable regulatory dockets, legislation, or other consideration relevant to the pilot project.	Selection of application for negotiation under Funding Opportunity Announcement Number DE-FOA-0003036: Energy Storage Demonstration and Validation, Topic Area 1

(2) Pilot design and evaluation plan designed and presented together	
a. Pilot design and evaluation plan designed and presented together.	Design: • Install a 10-hour 1.4 MW energy storage system co-located with Pine River's solar and wind renewable facilities • Perform augmentation by installing SLBs Evaluation: • The company will participate in data collection for the DOE's Rapid Operation Validation Initiative, and performance tests will be conducted every 6 months for 48 months from project start • Independent evaluation by EPRI and MTU for a period of two years after beginning commercial operation
b. If applicable, define target customer population, selection rationale, recruitment plans, and evaluation plans for customer adoption and satisfaction.	Not applicable
c. If statistical analysis will be conducted on pilot results, a statistically significant sample size	Statistical analysis will not be conducted. See (2) d. below.

must be selected, supported, and detailed. If a statistically significant sample size is not selected, justification must be provided.	
d. If statistical analysis will not be conducted, justification must be provided as well as an approach for evaluating pilot goals.	The project team will use a set of key performance indicators and targets to serve as quantitative metrics that will be used to evaluate the project's success: • Levelized cost of storage (LCOS): less than $0.05/kWh discharge • Cost of LDES augmentation using SLBs: <40% of cost of new modules • Site-level effective load carrying capability: 30% increase in ELCC over modeled increase with 4-hour system of same power capacity • System availability: >97% • AC roundtrip efficiency (excluding auxiliary load): 89% • Battery energy storage system state of health prediction accuracy at year 2 of operation: +/-1%

(3) Pilot project costs detailed	

a. Project costs are detailed by source and amount for all applicable periods.	Project cost by amount and source for duration of grant funding:
	• 01/01/2024 – 12/31/2024
	  ○ Federal – $222,961
	  ○ DTE Cost Share – $222,961
	  ○ Total - $445,922
	• 01/01/2025 – 12/31/2025
	  ○ Federal – $2,082,661
	  ○ DTE Cost Share - $2,082,661
	  ○ Total - $4,165,321
	• 01/01/2026 - 12/31/2026
	  ○ Federal - $2,180,109
	  ○ DTE Cost Share - $2,294,284
	  ○ Total - $4,474,392
	• 01/01/2027 - 12/31/2027
	  ○ Federal - $421,662
	  ○ DTE Cost Share - $421,662
	  ○ Total - $843,324
	• 01/01/2028 - 12/31/2028
	  ○ Federal - $92,607

	○ DTE Cost Share - $92,607 ○ Total - $185,215 Total Project Cost: • Federal - $5,000,000 • DTE Cost Share - $5,114,175 • Total - $10,114,175
b. Availability of non-utility funding and whether any was pursued (such as state or federal funding opportunities) described.	• Department of Energy cost share: $5M
c. Projected cost-effectiveness of piloted measure at scale over expected life described.	The DOE has defined cost competitive long duration energy storage as a system that has a levelized cost of storage of $0.05/kWh of discharged energy. ONE's projected cost for 2028 production achieves an all-in project cost of $0.057/kWh of discharged energy. Further product development may help drive the LCOS down below the DOE's threshold. Finding use cases that decrease the cost of charging energy (such as capturing otherwise curtailed or clipped renewable energy) may also help decrease the cost of discharged energy.

(4) Pilot timeline detailed	
a. Proposed timeline for the pilot project and any related reports or evaluations delineated.	Project timeline: • 2024 ○ DOE Review & Selection ○ DOE Award Negotiation ○ Commence engineering activities ○ Commence community benefits plan activities • 2025 ○ Obtain necessary modifications to MISO GIA ○ Obtain regulatory support ○ Commence procurement activities ○ Complete engineering activities ○ Commence construction activities ○ Commence data collection for DOE Rapid Operation Validation Initiative (ROVI) ○ Continue community benefits plan activities • 2026

	○ Complete procurement activities ○ Complete construction activities ○ Complete system commissioning and commence system operation ○ Continue data collection for DOE ROVI ○ Continue community benefits plan activities • 2027 ○ Complete augmentation with SLBs ○ Continue system operation ○ Continue data collection for DOE ROVI ○ Continue community benefits plan activities • 2028 ○ Complete data collection for DOE ROVI ○ Continue system operation ○ Continue community benefits plan activities Related reports or evaluations: • As part of the demonstration, DTE will participate in data collection for the DOE ROVI with technical support from EPRI. DTE will conduct a set of performance tests upon commissioning as well as every six months following commissioning for a period of 4 years post-commissioning. • Researchers from Michigan Technological University will perform a comparative life cycle analysis of using SLBs. Additionally, they will perform an evaluation to quantify the benefits this demonstration will bring to help drive the grid scale energy storage economy from linear to circular.

(5) Stakeholder engagement plan detailed	
a. Stakeholder engagement plan before, during, and after pilot takes place detailed.	• The Company will engage in regular meetings between all interested stakeholders. • The selected EPC contractor will coordinate with the local unions who provide workforce for the project • The company will issue reports, progress updates, and educational material as well as host sessions for stakeholders and provide opportunities for community feedback • Project updates to the community monthly, with potential increase of frequency as needed

b. Interim and final stakeholder reporting described.	Progress updates will be woven into stakeholder engagements described above
c. Expected publicly available data from pilot shared.	The company will participate in data collection for the DOE ROVI

(6) Public interest detailed	

a. Pilot support of the transition to clean, distributed energy resources, and its expected impacts described.	• Long duration energy storage will play important role in the transition due to the following attributes:
	  ○ Ability to serve as capacity resource
	  ○ Ability to provide ancillary services
	  ○ Ability to engage in energy arbitrage by charging during hours when locational marginal prices are lower and discharging during hours when locational marginal prices are higher
	• The pilot provides an opportunity to test the integration of long duration storage and renewables in firming variable renewable resources
	• The pilot provides an opportunity to test the utilization of second life electric vehicle batteries in long duration energy storage, avoiding the need to manufacture new battery packs to support augmentation
	• For additional detail, see (1) a. above.

b. Any added benefits to ratepayers or the energy delivery system, either due to proposed site selection or through other pilot variables, especially if any system weaknesses or forecasted needs are addressed, shared.	Proposed site selection and co-location with existing renewables provides benefits which include: • Reduced development installation costs • Increased utilization of existing interconnection • Ability to generate RECs for the otherwise curtailed energy and IRECs associated with storing renewable energy
c. Expected impacts of the piloted measure on reliability, resilience safety, and ratepayer bills detailed.	Hybridizing solar and wind renewable generation with long duration energy storage will smooth the variance of renewable generation across seasons, enhancing reliability.
d. Expected local or Michigan based employment and business	The Company has partnered with Novi-based Our Next Energy as the battery supplier for this project. The Company

opportunities created by pilot described.	will also utilize an engineering, procurement, and construction contractor, experienced in battery installation, who will be selected after the Company issues an RFP. The selected contractor will coordinate with all the local unions who will provide workforce for the project.
e. Any potential impacts or added benefits of the pilot on low-income customers, seniors or other vulnerable populations described.	The Pine River site is designated as an energy community by the Department of Energy, meaning it is a metropolitan statistical area" or "non-metropolitan statistical area" that has (or had at any time after 2009) 0.17% or greater direct employment or 25% or greater local tax revenues related to the extraction, processing, transport, or storage of coal, oil, or natural gas; and has an unemployment rate at or above the national average unemployment rate for the previous year. A Disadvantaged Community (DAC) is within a small section of St. Louis, MI within a three-mile radius of the project, according to the Climate and Economic Justice Screening Tool (CEJST). The EPA EJ Screen report states that 35% of the population is in the low-income bracket, the 62nd percentile in the U.S. This project location will provide members of the community with an opportunity to learn more about energy storage and clean energy.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for **DTE ELECTRIC COMPANY** to fully comply with Public Act 295 of 2008, as amended.	))))))	Case No. U-21662

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

CAITLIN D. MYERS states that on July 19, 2024, she served a copy of DTE Electric Company's Application, Direct Testimony and Exhibits of Witnesses, Kevin L. Bilyeu, Patrick D. Kauffman, Frank M. Kopinski, Kirk M. Vangilder, Sherri L. Wisniewski, Emily C. Meloche, Eddie Smith, and Nathan D. Bennett in the above captioned matter, via electronic mail, upon the persons listed on the attached service list.

Caitlin D. Myers

Digitally signed by Caitlin D. Myers
Date: 2024.07.19 13:53:36 -04'00'

CAITLIN D. MYERS

SERVICE LIST
MPSC Case No. U-21662

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