TROPOSPHERE LEGAL

August 23, 2024

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

Via E-File

RE: MPSC Case No. U-21534

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Revised Direct Testimony of Joshua Denzler on behalf of Citizens Utility Board of Michigan, Michigan Environmental Council, and Natural Resources Defense Council;
- Revised Direct Testimony of Douglas B. Jester on behalf of Citizens Utility Board of Michigan, Sierra Club, Michigan Environmental Council, and Natural Resources Defense Council;
- Correct Exhibit MEC-11 (adding a header); and
- Proof of Service.

Please note that there is a Confidential and Public Version of Mr. Denzler's testimony; the confidential version will only be served on those with a Nondisclosure Certificate on file in this case. There was previously a Confidential Version of Mr. Jester's testimony, however, with the revision, it is no longer confidential. Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Christopher Bzdok
DN: cn=Christopher Bzdok, o=Troposphere Legal, email=chris@tropospherelegal.com, c=US
Date: 2024.08.23 12:00:52 -04'00'

Christopher M. Bzdok
chris@tropospherelegal.com

CC: Parties to Case No. U-21534

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-21534

PUBLIC VERSION

REVISED DIRECT TESTIMONY OF JOSHUA W. DENZLER

ON BEHALF OF

CITIZENS UTILITY BOARD OF MICHIGAN,
MICHIGAN ENVIRONMENTAL COUNCIL,
AND NATURAL RESOURCES DEFENSE COUNCIL

August 23, 2024

TABLE OF CONTENTS

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Joshua W. Denzler. I am a Consultant at 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB), Michigan Environmental Council (MEC), Natural Resources Defense Council (NRDC).

Q. Please summarize your experience in the field of utility regulation.

A. My work experience is summarized in my resume, provided as Exhibit CUB-11. I have been in the utility industry since the summer of 2014, where I started my career at DTE Energy as a Summer Student (intern) working in continuous improvement for DTE Gas. After completing a second summer internship on the same team in the summer of 2015, I became a student co-op in Gas Construction and Planning.

I began my full-time career in 2017 when I became an Apprentice Planner in Electric Distribution Operations New Business Service Planning. In 2019, I became a Strategist in the Regional Customer Operations division of Electric Distribution Operations. I was promoted to Senior Strategist in this same organization in 2021. In late 2022, I became a Senior Strategist in Corporate Strategy supporting the Next Generation Utility effort before departing the company in early 2023. From that time until May 2024, I was employed by E Source Companies, LLC, as a Director of Sales Innovation responsible for marketing

advanced data science tools within the utility industry. I have been employed by 5 Lakes Energy since May 2024.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. I have not previously testified before the Michigan Public Service Commission or in any other similar proceeding.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of MNSC regarding the following topics:

1. The proposed Storm Recovery Cost Sharing Mechanism;
2. The Company's vegetation management risk prioritization model;
3. The proposed changes to Contribution in Aid of Construction (CIAC);
4. The Company's staffing baseline assumptions, particularly after their Voluntary Separation Incentive Package; and

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-11: Resume of Joshua W Denzler

Exhibit CUB-12: Case No. U-12270, June 14, 2024, DTE Electric Annual Report.

Exhibit CUB-13: Discovery Response MNSCDE-13.27

Exhibit CUB-14: Discovery Response MNSCDE-13.2b + *Confidential attachment* NDA_U-21534 MNSCDE-13.2b Preliminary Estimated Net VSIP O&M Savings

II. REQUESTED STORM RESTORATION COST SHARING MECHANISM

Q. Please summarize the Company's proposal for a Storm Restoration Cost Sharing Mechanism (SRCSM).

A. The Company is proposing that the current methodology for calculating projected storm restoration O&M costs remain consistent. However, the Company is proposing that, at the end of each year, the differences in actual incurred Storm costs versus projected costs, whether over or under the projection, would be split 50/50 between the Company and customers via regulatory asset or liability.[1]

Q. Is the Company's proposed SRCSM good for customers?

A. In general, no it is not. The proposal is likely to unduly skew the cost of Storms against customers and in favor to the Company and its shareholders. There are two main drivers of this imbalance inherent to the Company's proposal:

1. It skews the share of risk significantly in favor of the Company, at the expense of ratepayers.
2. It creates a strong misalignment of incentives, when the Company's historical storm performance is already very poor.

Q. How does the Company's proposed SCRSM create an imbalance of risk for customers?

A. The Company's proposal would reduce far more risk for the Company than it would for customers. If the increased storm severity projected by the Company are realized, it is much

[1] Revised Direct Testimony of Witness Foley, p. NTF-68.

more likely for costs to exceed projections than to be under projections. This means that cost collections from customers will be more likely than refunds to customers, resulting in a greater risk reduction for the Company than for customers.

Q. How has the Company's storm performance been in recent years?

A. The Company's overall storm performance can only be described as poor. Some of the most telling evidence of this comes from their SAIDI and SAIFI performance both in all-weather and excluding-Major Event Days (MED) conditions. The Company's all-weather SAIDI performance has been in the bottom quartile every year between 2017 and 2022, except for 2020. SAIDI Excluding MEDs has been mildly better comparatively, with 2020-2022 in third quartile while 2017-2019 is still in fourth quartile. A similar trend can be seen in the Company's SAIFI performance, where the Company generally ranks in lower quartiles for all-weather SAIFI as opposed to excluding-MED conditions.[2] For the Company's customers, this means that, while their overall reliability performance is rather poor when compared to other utilities, the Company's Storm performance is exceptionally poor in comparison to other utilities.

Further evidence to support the Company's poor Storm performance is found in the MPSC Service Quality and Reliability Standards for Electric Utilities Report Rule 460.731 for 2023.[3] This report shows that Company Storm response did not comply with the MPSC Annual Performance standards for Outage Restoration in All Conditions, Gray-Sky Conditions, and Catastrophic Conditions, among others.

[2] Direct Testimony of Kryscynski, pp. AJK-19-21, Figures 2-5.

[3] Ex CUB-12, Case No. U-12270, June 14, 2024, DTE Electric Annual Report.

As evidenced by both of these data sets, despite millions of dollars of investment, the Company's customers are receiving unduly long and more frequent outages during Storm events.

In addition to the Company's woeful underperformance in restoring Storm outages, their performance in communicating accurate restoration is also lacking. The Company stated that from 2018-2022, they did not even measure estimate accuracy outside of Blue-Sky days.[4] This shows a historic and systemic disregard for the impact of Storms and importance of accurate and timely communications with customers experiencing outages.

Continuing with this disregard is the fact that the Company only provides an estimated *day* of restoration during Storm events.[5] The wide potential for actual restoration across an entire day's time could make the difference on whether a customer will be able to work from home, if their food will spoil, and potentially even if they experience a medical emergency. Such a vague estimate leaves customers in a difficult position to properly respond to being without power.

While the broadness of these restoration estimates alone is far less than ratepayers deserve, the Company still underperforms in achieving them. The Company's Catastrophic Storm First Estimate accuracy was 46% in 2023 and the Non-Catastrophic Storm First Estimate accuracy was 60% in 2023.[6] The 2024 June YTD estimate accuracies are higher (70% for

[4] ExCUB-13, Discovery Response MNSCDE-13.27b.

[5] Ex CUB-13, Discovery Response MNSCDE-13.27a.

[6] Ex CUB-13, Discovery Response MNSCDE-13.27bi.

Catastrophic and 55% for non-catastrophic) but still represent a significant gap in the Company's service and communication to its customers.[7]

When the Company underperforms in restoring customers impacted by a Storm, those customers should at least have accurate information to respond accordingly to the overly frequent and unnecessarily long outages endure.

Q. Will the new proposal incentivize improvement in Storm spending and performance?

A. No, it will not. The Company states that the cost sharing proposal means the Company is "incentivized to control costs because it must absorb 50 cents of every incremental dollar that is spent."[8] If this were the case, the Company would be more incentivized to control costs if it had to absorb 100% of every incremental dollar that is spent. At bottom, the Company's proposal would mean that every incremental restoration dollar spent now would cost the Company only $0.50, when that dollar falls into the Storm category. This would create a financial incentive for the Company to extend the duration of Storms and perform additional work under the Storm umbrella as it would be 50% cheaper than if performed after Storm-close. Additionally, the Company has stated there is no current standard, other than field crew judgement, on when to repair versus replace field assets, and has not conducted a cost/benefit analysis to support any such decisions.[9] Particularly

[7] *Id.*

[8] Foley Revised Direct, p. NTF-71.

[9] Discovery Request MNSCDE-13.26a ("Refer to Hill p. BLH-17. Witness Hill discusses the downsides of deferring emergent replacement work. a. Please provide the company's processes and decision criteria for making decisions of repairing vs. replacing work and how it considered cost/benefit in developing these criteria. Answer: Field crews decide whether to repair or replace equipment based off their experience and judgment. For example, if a crew finds a broken wooden crossarm, they would not repair it but replace it

with the absence of any objective standard, the Company may alter Storm decision making to take advantage of this new cost share structure. Further misalignment of incentives would be driven by the fact that failure to keep storm restoration costs down would increase the size of the five-year trailing average storm cost projection that customers must pay. It is clear that the Company's proposal is not in the interest of ratepayers.

Q. If the Company's proposal is rejected, does that mean the Company has no other means to address the volatility from severe weather events?

A. Not, it does not. The Commission offers DTE an opportunity to earn a return on investment to compensate shareholders for risk. Earnings volatility, including earnings volatility due to storm cost recovery, is one of the risks the rate of return is intended to cover. From this perspective, DTE is already being compensated for storm recovery cost risk.

Q. What is your recommendation to address Storm cost recovery?

A. In light of the imbalance to the share of risk, the Company's poor Storm performance, and the likelihood for misaligned incentives, I recommend that the Commission reject the Company's SCRSM proposal. The Company's financial recovery from Storm should be tied to a balanced set of relevant performance metrics to ensure an alignment of incentives to the public interest. I recommend the Commission order DTE to develop Storm performance criteria that include outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to Storm scenarios and tie-bar financial recovery of excess Storm restoration costs to the Company's performance in these areas.

with a fiberglass crossarm. The Company has not done a formal cost/benefit analysis in determining these criteria.").

This would create an incentive for innovation and improvement so that customers receive the Storm restoration outcomes they deserve.

In light of the fact that the Company effectively receives compensation for weather volatility, should the Commission approve the Company's storm recovery cost sharing proposal despite my recommendation, I recommend the Commission reduce the rate of return it authorizes on these costs.

III. TREE TRIM RISK PRIORITIZATION MODEL

Q. How did the Company develop its Tree Trim risk prioritization model?

A. The Company implemented a risk prioritization model that leverages remote sensing data, advanced analytics, and machine learning to determine optimal trim cycles for their vegetation management work. This work was done with a combination of internal Company IT resources and an external consultant.[10]

Q. What should a risk prioritization model do?

A. There are two key objectives of a risk prioritization model when it comes to any utility program, including tree trim/vegetation management. The first objective is to accurately quantify the vegetation-related risk on a portion of the electric grid. The basic question it should answer is: "what is the risk of a tree related outage on this part of the grid, and how does it compare to the rest of the grid?" Ideally, this should be able to be done at sub-circuit resolutions, but at the very least it should be done at the circuit-level. Additionally, the risk

[10] Direct Testimony of Rachel C. Steudle, p. RCS-31.

of an outage should ideally be considered in conjunction with the expected customers impacted and the expected duration of the outage.

The second objective of the tool should be to accurately estimate the cost to mitigate the tree risk it identifies. This expected cost would likely be derived from expected labor hours and equipment needs based on the model's analysis of the necessary tree trim work. The purpose of this second objective is that it allows the utility to optimize its tree spend. A strong tree risk prioritization model will help the Company to estimate its cost per expected unit of reliability (i.e. SAIFI/SAIDI/CAIDI) avoided.

Q. How can the Company know if its risk prioritization model is effective?

A. When evaluating a vegetation management data modeling tool, utilities typically have two options: build the tool internally or purchase from an external vendor. While the Company did choose to build the tool internally, there exist many vendors in this space, from smaller start-ups to large and established corporate enterprises. A sample of key players includes: AIDash, Overstory, E Source, Hitachi, IBM, GE, Trimble, Leidos, and others.

In order to effectively evaluate the benefits of its risk prioritization model, the Company should evaluate its cost/benefit over time. The cost includes the cost to produce and maintain the model, but also the opportunity cost of what other models, internally or externally constructed, can be expected to do. The benefit can be measured by actual (for completed work) and projected expected (for future work) units of reliability avoided per dollars spent. This should be benchmarked against not only the Company's own baseline (i.e. what results they would see if they still used their previous planning methods) but

against the results seen by other utilities, both those with internally- and externally-constructed models.

Q. What is your recommendation as it relates to the tree trim risk prioritization model?

A. As this model is a new creation and previously untested, it is incredibly important to monitor its performance over time and ensure that tree trim resources are being deployed at absolute optimum. I recommend the Commission order an annual audit and evaluation into the Tree Trim planning and decision-making process, including the value of the risk prioritization model. As noted above, this evaluation should compare the Company's results to its previous baseline and the results seen by other utilities.

IV. PROPOSED CHANGES TO CONTRIBUTION IN AID OF CONSTRUCTION

Q. What are the Company's proposed changes for Contribution in Aid of Construction (CIAC)?

A. The Company is proposing substantial increases for thirteen different CIAC rate items. These increases are substantial with factors range from 2.4x - 6.1x the previous CIAC rate.[11]

The Company is taking a step forward by updating its CIAC rates – one that is long overdue as evidenced by the substantial amounts of proposed change. It is incredibly important that the Company ensure that CIAC stays accurate and relevant, so that new business customers pay their fair share of new business costs.

[11] Direct Testimony of Witness Brian L. Hill, pp. BLH-30-31, Table 5.

Q. What are your recommendations?

A. To ensure that implemented CIAC accurately reflects the current costs of construction and desired contributions, I recommend the Commission order a report in the next rate case proceeding detailing the impact of the CIAC changes. This should include a review of the new business construction costs and CIAC received, with comparison to historic and projections of future new business construction costs and CIAC received.

Additionally, the Commission should ensure that CIAC sees regular updates in the future so that it does not drift so far from actual costs again. To this end, I recommend the Commission order a regular review of CIAC costs. I recommend a review cadence of at least once every two years, but certainly no longer than once every five years.

V. COMPANY STAFFING BASELINE IN THE INSTANT CASE

Q. Please summarize the Company's Voluntary Separation Incentive Program.

A. On January 8, 2024, the Company offered a "Voluntary Separation Incentive Package (VSIP)" to 1,025 of its employees and 1,622 DTE Energy Corporate Services LLC employees.[12] This VSIP could otherwise be referred to or classified as a buyout. In discovery, the Company indicated 140 DTE Electric employees and 249 DTE Energy

[12] DTE Response to AGDE-1.23a ("A voluntary separation incentive package (VSIP) was offered to 1,025 DTE Electric employees and 1,622 DTE Energy Corporate Services, LLC employees (shared service employees) on January 8, 2024.").

Corporate Services, LLC employees accepted the VSIP, with projected costs of $30.6 million in 2024 and estimated savings of up to $20.2 million may materialize in 2025.[13]

Q. How is the Company treating the reduction in headcount post-VSIP in the instant case?

A. The Company has stated that any future savings are not embedded in the instant case and will instead be embedded into future rate cases.[14] In discovery response to MNSC, DTE provided an overview of the VSIP, which indicates [[ ]][15] DTE estimates the total projected savings of $20.2M in O&M savings in 2025.[16] This is subject to change based on potential future

[13] DTE Response to AGDE-1.23c ("140 DTE Electric employees and 249 DTE Energy Corporate Services, LLC employees accepted the VSIP. The package was not offered in 2023. There are no projected savings for 2024 due to DTE Electric's actual costs of the program (the accrued separation payments) of $30.6 million. A primary purpose of the VSIP was to realign the workforce to support the changing nature of the Company's work and how we do it, such as an increased focus on infrastructure investments, cybersecurity, and the clean energy transition.

Because of this, DTE Electric is still evaluating potential 2025 cost reductions due to the need to fill key roles so that we can continue our progress towards building more modern infrastructure and a future with lower carbon emissions. Currently, DTE Electric estimates that up to $20.2 million in expense reductions could materialize in 2025, inclusive of both labor and employee benefits. This estimate will continue to evolve due to the need to fill many key roles. This savings estimate also does not include any offset of the program costs. If actual savings are realized in 2025, they will be embedded in the Company's rates as actual costs in a future rate case.").

[14] Discovery Response AGDE-1.23c.

[15] Ex CUB-14C, Response to MNSCDE-13.2b, *Confidential Attachment* NDA_U-21534 MNSCDE-13.2b Preliminary Estimated Net VSIP O&M Savings.

[16]Ex CUB-14, Response to MNSCDE-13.2b; see also Discovery Response AGDE-1.23c.

hiring needs and does not include any costs associated with the program, which total $30.6M.[17]

Q. Is it reasonable for the Company to use pre-VSIP staffing levels as its baseline for cost recovery?

A. No, it is not. This is analogous to selling your home in June to move in rent-free with a relative, but still trying to deduct the mortgage interest for the whole year on your tax return. It does not make sense that the Company would include costs for employees that are no longer there. Since the Company elected to offer a buyout, it is reasonable to expect that staffing levels after that buyout should become the new budgetary norm. The Company should have to justify the expense of additional headcount above the VSIP-departures, not automatically receive those funds and then justify it down later.

Q. Why is it unreasonable for the Company to include backfilled positions in the instant case?

A. Essentially, the Company is asking the rate payers to bear the risk for the volatility of its staffing levels. The Company elected to do the buyout in 2024, and also chose to use 2025 as their projected test year, while still in the midst of significant staffing fluctuations. The Company has not properly justified its staffing baseline for 2025, as evidenced in their Discovery response to MNSC, where they stated "This estimate will continue to evolve..."[13]

[17] *Id.*

Q. What are your recommendations?

A. I recommend that the Commission establish the post-VSIP staffing cost as the baseline for the instant case for 2025 Total O&M Expense in Exhibit A-13 Schedule C5 based on VSIP departures to date, irrespective of any backfilling.

VI. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. On behalf of MNSC, I recommend that the Commission:

(1) Reject the Company's proposed Storm Restoration Cost Sharing Mechanism.

(2) Order the Company to develop a proposal to tie financial recovery from excess Storm spending to a balanced set of relevant performance metrics to ensure an alignment of incentives, using Storm performance criteria that include outage restoration, estimate accuracy, resource productivity, and financial responsibility specific to Storm scenarios.

(3) Order DTE to evaluate on an annual basis the Tree Trim planning and prioritization process, including the risk prioritization model, to ensure optimized deployment of those resources.

(4) Establish regular CIAC updates as a mandatory item in future rates.

(5) Establish the post-VSIP staffing costs as the baseline for the instant case, exclusive of any planned or completed backfills.

Q. Does that complete your testimony?

A. Yes.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-21534

PUBLIC VERSION

REVISED DIRECT TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

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

August 23, 2024

TABLE OF CONTENTS

REVISED DIRECT TESTIMONY OF DOUGLAS B. JESTER FOR MNSC
CASE NO. U-21534

I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am Managing Partner of 5 Lakes Energy, a Michigan limited liability corporation, located at Suite 218, 220 MAC Avenue, East Lansing, Michigan 48823.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Citizens Utility Board of Michigan (CUB), Sierra Club (SC), Michigan environmental Council (MEC), and Natural Resources Defense Council (NRDC).

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for more than 30 years in utility industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit CUB-17.

Q. Have you testified before this Commission or as an expert in any other proceedings?

A. I have previously testified before the Michigan Public Service Commission ("Commission") in the following cases:

- Case U-17473 (Consumers Energy Company Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);

- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);

- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18232 (DTE Renewable Energy Plan);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20072 UPPCO 2017 PSCR Reconciliation);
- Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- Case U-20134 (Consumers Energy General Rates);
- Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint);
- Case U-20162 (DTE General Rates);
- Case U-20165 (Consumers Energy Integrated Resource Plan);
- Case U-20229 (UPPCO 2019 PSCR Plan Case);
- Case U-20276 (UPPCO General Rates);
- Case U-20350 (UPPCO Integrated Resource Plan);
- Case U-20359 (I&M 2019 General Rate Case);
- Case U-20471 (DTE Integrated Resource Plan);
- Case U-20479 (SEMCO 2019 General Rate Case);
- Case U-20561 (DTE 2019 General Rate Case).;

- Case U-20591 (Indian Michigan Power Company IRP);
- Case U-20642 (DTE Gas 2020 General Rate Case).;
- Case U-20649 (Consumers Electric Voluntary Green Pricing).;
- Case U-20650 (Consumers Gas 2020 General Rate Case);
- Case U-20697 (Consumers Electric 2020 General Rate Case);
- Case U-20713 (DTE 2020 Voluntary Green Pricing);
- Case U-20836 (DTE Electric 2022 General Rate Case);
- Case U-20874 (Alpena Power 2022-23 EWR Plan Case);
- Case U-20875 (Consumers Energy 2022-23 EWR Plan Case);
- Case U-20876 (DTE Electric 2022-23 EWR Plan Case);
- Case U-20877 (Indiana Michigan 2022-23 EWR Plan Case);
- Case U-20878 (NSP 2022-23 EWR Plan Case);
- Case U-20879 (UPPCO 2022-23 EWR Plan Case);
- Case U-20880 (UMERC 2022-23 EWR Plan Case);
- Case U-20881 (DTE Gas 2022-23 EWR Plan Case);
- Case U-20882 (MGU Gas 2022-23 EWR Plan Case);
- Case U-20883 (SEMCO Gas 2022-23 EWR Plan Case);
- Case U-20889 (Consumers Karn Retirement Securitization);
- Case U-20963 (Consumers Energy Electric Rate Case);
- Case U-21015 (DTE Securitization Case);
- Case U-21048 (Consumers Energy 2022 PSCR Plan);
- Case U-21081 (UMERC 2021 IRP);
- Case U-21090 (Consumers Energy 2021 IRP);

- Case U-21189 (Indiana Michigan 2022 IRP);
- Case U-21193 (DTE Electric 2022 IRP);
- Case U-21224 (Consumers Energy 2022 Electric Rate Case);
- Case U-21297 (DTE Electric 2023 Rate Case);
- Case U-21377 (IM Renewable Acquisition);
- Case U-21389 (Consumers Energy 2023 Electric Rate Case);
- Case U-21540 (MGU 2024 Gas Rate Case); and
- Case U-21555 (UPPCO 2024 Rate Case).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource Plan of NV Energy; and before the Missouri Public Service Commission in Case Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities Commission, in case 4780, I testified concerning Advanced Metering Infrastructure and EV charging infrastructure. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in case 17-1094. I testified before the Georgia Public Service Commission in Case No. 4822 concerning PURPA avoided cost. I testified before the Colorado Public Utilities Commission in Cases No. 20A-

0204E and 20A-195E concerning cost recovery for EV charging infrastructure. I also testified before the Minnesota Public Utilities Commission in Case No. 22-432 regarding EV charging rate design.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-17:	Resume of Douglas B. Jester
Exhibit CUB-18:	*Reserved*
Exhibit CUB-19:	Electric Vehicle Charging Profiles

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. My testimony will address the following topics:

1. Rate recovery of outage bill credits;
2. Securitization of tree trimming surge costs;
3. Rate design issues;
4. Transportation electrification.

Q. Which Company witnesses' testimony do you discuss in your testimony?

A. I am addressing the testimony of Company witnesses Neal T. Foley, Habeeb J. Maroun, Aaron Willis, and Pina Bennett.

III. OVERVIEW OF DTE ELECTRIC'S APPLICATION

Q. Please summarize DTE Electric's rate request.

A. As presented in DTE Electric's Rate Case Summary, DTE Electric is proposing $456 million annual revenue increase, driven substantially ($285 million) by increases in rate base but with material increases due to cost of debt and capital structure ($36 million), increased return on equity ($63 million), and operating cost increases ($72 million). The rate base increase includes $927 million in utility plant additions. This revenue increase results in a 9.6% increase for residential customers, an 8.9% increase for secondary residential customers, a 4.3% increase for primary customers, a 2% reduction of rates for economic development customers (D13 XL), and 6% increase of lighting customers.

The underlying capital expenditures driving rate base increases are shown in Exhibit A-12 Schedule B5 and a substantial majority is to be spent on the DTE Electric's distribution system.

Q. How should the Commission approach this case?

A. DTE Electric's electricity costs are comparatively high for residential and commercial customers and average for industrial customers. DTE Electric's reliability is poor,

particularly when Major Event Days are included. The following table from CUB's annual utility performance report shows DTE Electric's comparative performance in 2021.[1]

2021 DTE Electric Company Performance Summary

Metric	Value	Michigan	US Average	IOU Rank
Number of Electricity Customers Across All Sectors	2249459	5014447		1
SAIDI with Major Event Days (Minutes)	927.4	873	440	7
SAIDI without Major Event Days (Minutes)	135.6	177.9	119.9	2
SAIFI with Major Event Days (# of Outages)	1.581	1.656	1.396	2
SAIFI without Major Event Days (# of Outages)	0.924	1.03	0.998	1
CAIDI with Major Event Days (Minutes)	586.6	527	315	7
CAIDI without Major Event Days (Minutes)	146.8	172.6	120.1	4
Residential Electricity Price ($)	0.17856	17.61	13.07	5
Commercial Electricity Price ($)	0.10519	11.69	9.81	1
Industrial Electricity Price ($)	0.06371	6.68	6.12	3
Residential Electricity Savings from Efficiency Programs as a % of Sales	1.747	1.405	0.846	3

In this case, DTE Electric proposes revenue increases well in excess of inflation rates. In general, and particularly when a utility has comparatively high rates, the Commission should be wary of rate increases that exceed general inflation. Generation fuel prices are volatile and technology mix is changing which can engender electricity price variation, but electricity generation, transmission, distribution, metering and utility operations are mature businesses that should show long-term trends of improving productivity and relative cost declines.[2]

[1] CUB Utility Performance Report 2023 Edition, p. 8. Data availability lags for some data used in the report cause a delay between the data year and the report year. The 2024 edition is currently in preparation.

[2] Direct testimony of Matthew Bandyk, pp. 3-4.

I therefore recommend that the Commission approach all rate cases from the perspective that a utility should be managing its operations to limit rate increases to the general inflation rate or less. At the same time, the Commission should be focused on ensuring that DTE Electric is accountable for improving distribution reliability.

IV. OUTAGE CREDIT RECOVERY

Q. What proposal is the Company making in this case with regard to outage credit recovery?

A. As described by DTE Electric witness Neal T. Foley,[3] the Company proposes that outage bill credits provided to customers pursuant to the Commission's Service Quality and Reliability Standards for Electric Distribution Systems (Mich Admin Code R460.701-752 that result from certain causes be deferred for subsequent recovery.

Q. For what causes of outages does DTE Electric propose to recover bill credits?

A. For bill credits paid when DTE Electric's restoration of service exceeds durations specified in the rules when the outage causes are:

- Transmission operator or other utility
- Public interference
- Animal interference

For bill credits paid when a DTE Electric customer experiences excessive outage frequency, the causes listed above for excessive outage duration and also outages caused by:

[3] Direct testimony of Neal T. Foley, NTF-30:12 through NTF-33:25.

- Ice
- Lightning
- Wind
- Other weather

Q. Do you agree with this proposal?

A. No. This proposal is reflective of DTE Electric's continuing resistance to accountability for its performance as owner and operator of its distribution system.

An outage attributable to a transmission operator or other utility must be fixed by that party. It is therefore reasonable to provide a limited recoverability of bill credits due to such outages, though the proper public policy would be that DTE Electric must recover that cost from the responsible party.

Aside from this limited exception, the Commission should reject this proposal. An outage duration exceeding the Commission's standards reflects DTE Electric's failure to timely repair the problem and restore service, even if the outage is caused by public interference or animal interference. If the outage is caused by public interference, DTE Electric can seek recourse from the responsible party and if that isn't possible, this is nonetheless a case in which DTE Electric should reasonably be expected to timely restore service. Animal interference is an event that DTE Electric and any other utility should expect to happen in its distribution system and which they should be prepared to timely repair.

The Commission's outage frequency limits, at 6 or more in a 12-month period, are already generous to the utility. DTE Electric's proposal to recover bill credits for weather

effectively excludes a majority of their outage occurrences and would completely undermine any accountability for ensuring that their distribution system is robust enough to provide satisfactory service. The Company's rationale "that the Company controls the restoration time when there is a weather event but not the frequency with which weather events occur"[4] is unavailing because the Company does control the vulnerability of its distribution system to weather.

Q. What other considerations apply to this proposal?

A. DTE Electric has persistently had amongst the worst reliability records of any investor-owned utility over several decades. The Commission has given considerable attention to this problem over those decades to little avail.[5] The rules in question are one of the few measures that the Commission has undertaken to hold utilities accountable for performance, albeit in a very modest way. The Commission has not reduced return on equity, held utility management to high standards, administered significant penalties for violation of the Service Quality Standards, nor taken any other actions to hold utilities accountable even as utilities spend billions on supposed distribution system improvements. For the Commission to grant this request by DTE Electric would demonstrate the Commission's abject inability to hold a utility accountable for its performance.

[4] Direct testimony of Neal T. Foley, NTF-32:15-19.

[5] See the presentation by Douglas Jester in the Commission's 2021 Technical Conference on Emergency Preparedness, Distribution Reliability, and Storm Response, available from https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/technical-conference/Session_2_Master_Slide_Deck_-_Tech_Conf_11-5-2021.pdf as of 20 July 2024.

V. TREE TRIMMING SURGE SECURITIZATION

Q. What proposals has DTE Electric made in this case regarding costs of its tree trimming surge?

A. DTE Electric has made two proposals. First, they propose that the Company be allowed a return on the tree trim regulatory asset accumulated as a result of the tree trim surge at the Company's long-term cost of permanent capital. MNSC Witness Paul Alvarez testifies in opposition to that proposal, and I endorse his testimony and recommendation.

Second, they describe their intent to securitize the costs of the tree trim surge after the surge program concludes, capturing all expenditures not previously securitized. I support that plan but strongly advise that DTE Electric assume that the same conditions will apply to this securitization as the Commission ordered in Case No. U-21015.

VI. RATE DESIGN

Q. Are there other considerations that the Commission should apply to changes in rate design?

A. Yes. As MNSC witness Graham Woolley shows, the effective capacity of the distribution system is seasonal. Currently aging of line transformers occurs almost exclusively occurs during Summer months June through August. As both he and MNSC witness David Gard show, utilization of the effective capacity of the distribution system is highly seasonal, both because nominal loads are lower in non-summer seasons but also because transformer effective rating is higher when ambient temperatures are lower. With capacity that varies seasonally, the proper basis for both cost of service and rate design of distribution costs is

the degree of capacity utilization, not nominal loading. On that basis, distribution system rates should be seasonal.

Additionally, I note that MNSC witness David Gard shows very clearly that the ratios of coincident and non-coincident peak demands to annual energy vary significantly within the broad residential class both as between single-family and multi-family dwelling types and according to the degree of electrification of buildings and automobiles. I reiterate and support his recommendation that these become the basis for separate residential customer rate classes in the future. In particular, I recommend that the Commission require DTE Electric to present in its next rate case a cost-of-service study and corresponding rates in which residential customers are divided into Multifamily, Single-Family with electric space heating, and Single-Family with fossil-fueled space heating. For these purposes, a Single-Family class should include duplexes and mobile homes since these appear to have similar load profiles. The Commission should also note that in addition to the load profile differences between Single-Family and Multi-Family dwellings, the infrastructure requirements in the form of utility-owned line transformers, service lines, etc., for a typical Multi-Family dwelling unit are often quite different from those for Single-Family buildings; it is therefore likely that there are material differences in distribution system costs caused by these two dwelling types.

I note that while this will add some complexity to the residential cost of service analysis, each of the resulting residential classes will be larger by both customer count and electricity demand than several of the commercial and industrial classes and all of the public lighting

classes. It would also be appropriate for the Commission to consider subdividing the Secondary Commercial General Service Rate class by space heating heat source.

Q. Witnesses David Gard and Graham Woolley present analyses focused on transformers. Does the argument apply to other elements of the distribution system?

A. Yes. We are presenting the transformer analysis to illustrate that this is a significant consideration, but ambient temperature is important to most elements of the distribution system and should be considered across all of those elements. For example, the current-carrying capacity (ampacity) of conductor is significantly influenced by ambient temperature as represented in the Neher-McGrath equation.[6] I have long found the ISO New England Capacity Rating Procedures document,[7] though old, a convenient reference to considerations of the effects of ambient temperature on transmission element ratings and those same considerations also apply to distribution systems as they are composed of similar but smaller elements.

Q. Doesn't DTE Electric already have separate rate schedules for both residential and commercial space heating?

A. Yes, but those rate schedules mostly require separate metering, which is an unnecessary expense to both DTE and the customer. Most are also interruptible, which may not appeal to all customers. Rate Schedule D1.7 is limited to geothermal (ground source) heating. Further, in the event that considerable building electrification occurs in future, as some

[6] Neher, J. H.; McGrath, M. H. (October 1957). "The Calculation of the Temperature Rise and Load Capability of Cable Systems". *AIEE Transactions*. **76** (III): 752–772.

[7] See capacity_rating_procedures.pdf (iso-ne.com).

current public policy favors, the aggregate of these excess metering and billing costs could become quite large. It will be less costly and more sustainable over the long term to simply treat customers with electric space heating as a separate class.

Q. What would be the benefits of the changes in rate design that you are recommending?

A. There are three principal benefits. First, both the use of seasonal rates and breaking up the residential class by dwelling type and space-heating technology will result in more accurate assignment of revenue responsibility to customers. At present, it is almost certainly the case that multi-family residential customers subsidize single-family residential customers and that customers that have electric space heating but do not have space heating separately metered are subsidizing customers that use fossil-fueled space heating. These overlap in that electric heating is a much larger share of Multi-Family housing than it is of Single-Family housing. An important consequence is likely that low-income households, who disproportionally occupy Multi-Family housing with electric heating are significantly subsidizing better-off households occupying Single-Family housing and using fossil-fueled heating. Appropriately separating these classes to determine cost of service and construct different rate schedules could significantly reduce current inequities in electric utility bills.

Second, such changes in rate design would provide price signals to residential customers that would guide equipment selection and other investments and energy consumption behavior that will, in the long run, reduce electric utility costs to society and individual customers.

Third, these changes in rate design will promote electrification by making electricity cheaper at the times space heating is needed, which will reduce pollution emissions and dilute utility fixed costs over higher sales.

Q. You did not recommend separate residential classes based on electric vehicle ownership or behind-the-meter generation. Why not?

A. With respect to electric vehicle ownership as a customer classifier, that is likely to change more quickly than home heating. Further, I recommend a different approach to managing electric vehicle charging in the portion of my testimony covering DTE Electric's Transportation Electrification Plan and electric vehicle charging programs.

With respect to behind-the-meter distributed generation, the Commission has already adopted the inflow-outflow framework and required a Rider for eligible customers that prescribes compensation for outflow. In the event that analysis shows that there should also be differences in inflow rates for such customers, that could also be done through the Rider as sur-credits on inflow rates. So, structurally it appears cleaner to not proliferate additional rate schedules to accommodate customer adoption of behind-the-meter distributed generation.

Q. Do you recommend that the Commission adopt these rate design changes in the present case?

A. No. Data are not available in this case for the full analysis of these recommendations. The analysis of rate designs based on these recommendations would be contingent on Commission decisions about cost-of-service treatment of Production Plant, seasonality of distribution system cost of service, classes to use in the analysis, and perhaps other things.

It would be more appropriate for the Commission to provide some guidance as to the rate design considerations that it would like to consider or adopt, and require DTE Electric to submit the requisite analyses and rate design recommendations in a future case.

Q. Please summarize your rate design recommendations to the Commission.

A. I recommend that the Commission require that DTE Electric file in its next rate case an analysis of the seasonality for cost causation of distribution costs and distribution rate designs consistent with that seasonality.

I recommend that the Commission require that DTE Electric file in its next rate case an alternative cost of service study that separates Residential customers into Multi-Family, Single-Family with electric space heating, and Single Family with fossil-fueled space heating, such that the Commission can decide in that case whether this approach should be adopted.

Finally, I recommend that the Commission encourage DTE Electric to engage with stakeholders in performing these analyses, rather than waiting until the next rate case is filed.

VII. TRANSPORTATION ELECTRIFICATION

Q. Please summarize DTE Electric's Transportation Electrification proposals in this case?

A. In this case, DTE Electric presents

- an analysis of cost of service and rate design if Direct Current ("DC") Fast Chargers are treated as a separate class, covered in the testimony of Habeeb Maroun[8] and Aaron Willis[9];
- its Transportation Electrification Plan ("TEP" or "Plan"), including background on the Company's development of the TEP;[10] DTE's proposed TEP program portfolio;[11] a benefit-cost analysis of the TEP;[12] and the proposed investments associated with the TEP.[13]

Within this presentation, DTE Electric proposes:

- To not implement a DC Fast Charging class in cost-of-service analysis or a distinct DC Fast Charging rate at this time, but to revisit these in the future when the DC Fast Charging customer base is larger and utilization is nearer market equilibrium;[14]
- To charge a customer installing electric vehicle charging Contribution in Aid of Construction ("CIAC") consistent with existing line extension policy with an allowance for expected revenue from that specific charger;[15]

[8] Direct Testimony of Habeeb J Maroun, HJM-27:9 through HJM-25:20.

[9] Direct Testimony of Aaron Willis, AW-34:15 through AW-36:17.

[10] Direct Testimony of Pina Bennett, PB-14:15 through PB-37:6.

[11] Direct Testimony of Pina Bennett, PB-37:8 through PB-52:17.

[12] Direct Testimony of Pina Bennett, PB 52:19 through PB-59:21.

[13] Direct Testimony of Pina Bennett, PB-59:23 through PB-62:15.

[14] Direct Testimony of Aaron Willis, AW-36:12-17.

[15] Direct Testimony of Pina Bennett, PB-35:3-4.

- To base its spending plans on its own forecast of electric vehicle adoption in its service territory;[16]
- To not include utility-owned pole-mounted chargers in this initial TEP;[17]
- To offer customers rebates for installing electric vehicle charging infrastructure as summarized in Table 9 of the testimony of Pina Bennett,[18] with rebate amounts set at levels intended to offset CIAC costs for program participants only in limited cases;[19]
- To require low-income customers obtaining a home charger rebate to use an ENERGY STAR or vehicle manufacturer charger less than 12 kW and enrollment in a Time-of-Day rate;[20]
- To require recipients of Business Charger rebates to use networked chargers, share data with DTE Electric, and maintain 97% charger uptime, with additional requirements for larger rebates available to businesses located in a disadvantaged community or in rural areas;[21]
- To require Multi-unit Dwelling installations to meet certain low-income/disadvantaged community criteria and to use a networked charger,

[16] Direct Testimony of Pin Bennett, PB-35:5-6.

[17] Direct Testimony of Pina Bennett, PB-35:7.

[18] Direct Testimony of Pina Bennett, PB-38, Table 9.

[19] See Direct Testimony of Pina Bennett, PB-42:19-25 (describing rebates for qualified low-income MUDs as intended to cover "the CIAC portion of the utility make-ready and the customer make-ready.").

[20] Direct Testimony of Pina Bennett, PB-41:11 through PB-42:3.

[21] Direct Testimony of Pina Bennett, PB-47:8-17.

authorize data sharing with DTE Electric, commit to 97% charger uptime, and have demonstrated tenant interest in installing electric vehicle chargers;[22]

- To require recipients of Fleet Charging rebates, including for transit bus and school bus charging, to install a qualified, networked charger, authorize data sharing with DTE Electric and commit to demand ceilings in constrained areas and for school bus chargers to include vehicle-to-grid chargers for a greater rebate;[23]
- To not support rebates for workplace charging on the basis that there is sufficient incentive for workplaces to install chargers to attract employees;[24]
- To discount rebates to Electric Choice customers.[25]

To implement the proposed TEP portfolio, DTE requests approval of approximately $25 million in the 2025 projected test year, of which about $1.6 million will be capital for Information Technology capabilities to support the Program, about $3.2 million will be expenses for program administration and education and outreach, and about $20.1 million of expenditures for customer rebates and an Emerging Technology Fund will be booked as a regulatory asset to defer cost recovery.

Q. What is your assessment of DTE Electric's proposed TEP?

A. DTE Electric's TEP is a positive development and I urge DTE Electric and the Commission to continue with periodic revisions and implementation of such plans. I have a few specific

[22] Direct Testimony of Pina Bennett, PB-44:4 through PB-45:3.

[23] Direct Testimony of Pina Bennett, PB-49:8-15.

[24] Direct Testimony of Pina Bennett, PB-50:16-18.

[25] Direct Testimony of Pina Bennett, PB-50:19-22.

concerns about this Plan, and find that the benefit-cost analysis is incorrect and should not be the basis for limits to this and future TEPs.

Q. What are your specific concerns about the Transportation Electrification Program?

A. My principal concern is DTE Electric's decision to apply CIAC practices to electric vehicle charging based on current line extension policy. I also find the decision not to support workplace charging to be blind to some specific circumstances in which support should be provided. The proposal to discount rebates to Electric Choice customers is based on incorrect premises. The Plan gives insufficient attention to the integration of vehicle charging into the grid as electric vehicle adoption reaches high levels, and likewise gives insufficient attention as to how TEP programs may support or complement federal funding for EV charging and transportation electrification initiatives.

Q. What is your concern about the application of line extension policy for installation of electric vehicle charging?

A. It is highly likely that this policy will create unwarranted inequities and barriers to electric vehicle adoption. Customers who happen to be located in places where distribution system infrastructure is saturated will pay to upgrade the distribution system while customers who happen to be located where there is surplus capacity will not. As electric vehicle adoption proceeds, early adopters in a residential or commercial neighborhood may not need to pay CIAC but at some point capacity limits will be reached and the unfortunate customer who happens to adopt an electric vehicle at the wrong time will be asked to pay CIAC, and the upgrade will then provide capacity for many subsequent adopters who will not have to pay CIAC. A similar pattern could occur with DC Fast Charging; for example, an area near a

highway exit could host a few DC Fast Chargers without expense then reach a capacity limit such that the next DC Fast Charger installation would incur significant CIAC. Word of mouth information about large utility upgrade costs for electric vehicle adoption will discourage people from adoption and discourage commercial installers from developing a sufficient network of public charging infrastructure, particularly DC Fast Charging, which DTE correctly assesses will fulfill the majority of public charging needs.[26]

DTE Electric's forecast of electric vehicle adoption is that it will be widespread and perhaps ubiquitous.[27] Under these circumstances, rather than randomly charge some customers CIAC while many others do not pay CIAC, based on conditions that are not under their control, it would be far better policy to socialize the costs of grid upgrades to accommodate electric vehicle charging. I therefore recommend that the Commission direct DTE to waive CIAC for all new residential and commercial installations of EV charging, whether installing customers are participants in DTE's TEP programs or not. This would extend and expand the Company's prior policy of waiving CIAC for participants in the Charging Forward programs.

By socializing the costs of grid upgrades, those costs can then be paid out of the aggregate new revenue that will be provided by electric vehicle charging across DTE's distribution system, rather than expecting that revenue from each individual charging location will cover the costs that happen to be incurred by that particular charging location at that particular time. The cost of such grid upgrades should be considered as part of any benefit-

[26] Direct Testimony of Pina Bennett, PB-26, Table 4.

[27] Direct Testimony of Pina Bennett, PB-23:5 through 25:4.

cost analysis or ratepayer impact analysis of the Company's transportation electrification programs and investments.

Q. In what circumstances might support for workplace charging be appropriate?

A. It is likely often the case that employers with private parking for employees will find it useful to provide electric vehicle charging for employees. However, workplace charging is not always privately held by the employer and may be shared (as at a shopping mall or multi-tenant office building), in common area parking in a downtown district, or in municipally owned parking. In these cases, employees seeking electric vehicle charging may encounter the same difficulties that DTE Electric recognizes for multi-unit dwellers. It would be appropriate to extend the rebate program to these circumstances.

Q. What is wrong with DTE's premises for discounting rebates to Electric Choice customers?

A. The stated premise is that Electric Choice customers contribute less revenue to DTE Electric than full-service customers, so a discount is appropriate. However, it is not gross revenue that supports electric vehicle charging programs, but net revenue where the principal cost that must be netted out is the cost of power supply. Net revenue is almost entirely attributable to paying full rates for charging while the utility does not incur corresponding costs for distribution system upgrades. Net revenue from charging at the premises of an Electric Choice customer is likely to be similar to net revenue from charging at the premises of a full-service customer.

Q. What more should DTE Electric do to address integration of vehicle charging into the

grid as electric vehicles reach higher levels of adoption?

A. DTE Electric has taken some reasonable first steps to integrate electric vehicle charging into the grid by encouraging or requiring customers participating in its Charging Forward programs to use Time-of-Day rates and by initiating the pilot DTE Smart Charge program. I generally support continuing to condition customers' participation in the Company's TEP programs on their agreement to manage their EV charging load.

To demonstrate that Time-of-Day rates are likely to be insufficient in the long run, I modeled load profiles in two scenarios using the National Renewable Energy Laboratory's EVI-Pro Lite tool.[28] In both cases, I used the Detroit urban area for the analysis and developed the load profile for charging 40,000 electric vehicles. The results are shown in Exhibit CUB-19. The specifications of each scenario are shown in the Exhibit next to the charging load profiles. In the first scenario, charging at home is assumed to be delayed until midnight, as someone might program their car or home charging station to do if they take service on a Time-of-Day rate in which the low-cost period begins at midnight. In the second scenario, charging at home is assumed to begin immediately after the car returns home from the last trip of the day but the charging is spread evenly as slowly as possible for readiness the next morning. It should be noted that the vertical axes have different scales in the two scenarios. The first scenario, which is very like DTE Electric's current approach to grid integration of electric vehicle charging, produces a very high demand immediately upon the start of the low-priced period at midnight, and then diminishes fairly quickly overnight and has comparatively low charging demand through the rest of the day. The

[28] Accessible at https://widgets.nrel.gov/eere/evi-pro-lite/#/load-profile.

second scenario has a much more even demand throughout the day and will be much easier to match to generation. Further, the second scenario would be much easier to accommodate in the distribution grid.

Additionally, DTE Electric has not compared charging profiles to the expected grid load net of renewables. As DTE Electric and other Michigan utilities increase their renewable energy portfolios to meet recently adopted renewable and clean energy standards, the best time of day to charge is likely to evolve and perhaps be seasonal. Flexibility to avoid charging during extended periods of low renewable generation and to fully charge during periods of high renewable generation, and especially if renewable curtailment will otherwise occur, will also be valuable. Such flexibility is difficult if not impossible to capture in a static rate design. DTE Electric's current Transportation Electrification Plan seems to assume that grid conditions will remain as they are now and does not account for dynamics due to transportation electrification and increasing renewable generation.

I recommend that the Commission require DTE Electric to provide 8760-hour annual load profiles in addition to the other metrics the Company proposes to track[29] to enable stakeholders to work on this problem.

I also recommend that the Commission require DTE Electric to prepare a supplement to its Transportation Electrification Plan that addresses grid integration of electric vehicle charging by providing a forecast of load profiles at line transformers, circuit feeder origination at the substation, and at generation when electric vehicle charging is combined

[29] Direct Testimony of Pina Bennett, PB-52:1-17.

with existing loads at various levels of electric vehicle adoption and by also providing an analysis of load net of renewable generation at various levels of electric vehicle adoption with Michigan attaining 50% renewables, 60% renewables, and 80% renewables. Challenges exposed by these analyses should then be addressed through plans or pilot projects, which may include managed charging programs and/or dynamic rate designs akin to those identified by the Company in its survey of sister utilities' TEPs.[30]

Q. What more should DTE Electric do to ensure its TEP programs support and complement federal funding and initiatives for transportation electrification?

A. DTE Electric's proposed TEP programs recognize some federal transportation electrification efforts. For example, the Company would require rebate recipients in the Business Charger and Multi-family programs to meet uptime standards aligned with federal standards for National Electric Vehicle Initiative. It also recognizes "support to on-route DCFCs not in DAC or rural areas" is "critical in the near-term to decrease range anxiety and to complement federal funding opportunities, such as the NEVI program."[31]

However, there is considerable room for improvement.

DTE Electric's proposed TEP programs partially recognize the value of alignment with some federal transportation electrification efforts. For example, the Company would require recipients of rebates for on-route charging as part of the Business Charger Rebates

[30] Direct Testimony of Pina Bennett, PB-16:3 through 23:3 (noting the prevalence of "requirements or incentives that support managed charging or Time of Day rates" in other utilities' TEPs).

[31] Direct Testimony of Pina Bennett, PB-46:22-25.

program to meet uptime standards[32] that are aligned with the federal standards for National Electric Vehicle Infrastructure ("NEVI") program. And, to qualify for higher rebate amounts for on-route charging, participants would need to locate charging in disadvantaged communities as defined by the Michigan State Plan for EV Infrastructure Deployment (a plan developed pursuant to the NEVI program) or a rural area as defined by the U.S. Department of Transportation.[33] DTE further recognizes that "support to on-route DCFCs not in DAC or rural areas" is "critical in the near-term to decrease range anxiety and to complement federal funding opportunities, such as the NEVI program."[34]

At the same time, there is room for greater coordination. First, DTE's Business Charger Rebate program for on-route charging directly overlaps with the market segment to be served by the state through its limited NEVI funding,[35] which, for select projects, provides support for up to 80% of the project cost. NEVI funds may not be used for major grid upgrades and federal guidance discourages use of funds for any utility-side costs, instead encouraging states to "explore whether they could be covered by electric utilities ... so as to minimize use of NEVI funds for grid upgrades where possible."[36] To connect these programs and stretch Michigan's limited NEVI funds further, DTE's rebates for on-route charging should be available for "utility make-ready," which the Company defines to include "upgrades on the utility side of the meter, from the line transformer to the meter,"

[32] Direct Testimony of Pina Bennet, PB-47:10-12.

[33] Direct Testimony of Pina Bennett, PB-47:14-17.

[34] Direct Testimony of Pina Bennett, PB-46:22-25.

[35] Michigan's funding is ~$110M. See https://www.ampeco.com/blog/nevi-program-faq/.

[36] https://www.ampeco.com/blog/nevi-program-faq/.

as well as "customer make-ready," which includes "upgrades on the customer side of the meter, from after the meter to the EV charger." Unfortunately, DTE's testimony does not specify whether the Business Charger Program rebates will be available for those cost categories or available only for the "EV Charger." I therefore recommend that DTE clarify that its Business Charger Rebates for on-route charging are available to defray utility make-ready, customer make-ready and EV charger costs as defined in Table 7 of Witness Bennett's testimony.[37]

Second, to the extent practical, DTE should prioritize Business Charger Rebate program applications from prospective participants that are also seeking (or have secured) funding through the state's NEVI program. Such coordination is consistent with the Commission's directive in U-21297 "requiring the [Business Charger Rebate] program [to] be coordinated with NEVI as ... that may enhance the program's goals."[38] Relatedly, DTE should work with prospective program participants to site EV charging stations within census tracts eligible for the Alternative Fuel Vehicle Refueling Property Tax Credit as extended and modified by the Inflation Reduction Act.

Third, with respect to the eFleet Charger Rebate for school and transit buses, the Company should similarly seek to prioritize applicants that are seeking (or have secured) funding through federal programs for zero-emission buses, like the Clean School Bus program and the Low or No Emissions Grant Program for transit buses. Through its education and outreach efforts, DTE should support transit agency or school districts' efforts to secure

[37] Direct Testimony of Pina Bennett, PB-36:1-4.

[38] Case No. U-21297, Dec. 1, 2023, Order, p. 266.

such grants through technical assistance and grant-writing support. DTE also should clarify that rebates are available for "utility make-ready" and "customer make-ready" in addition to EV Chargers, as some of these costs are not eligible expenses with federal grants and use of DTE rebates for those expenses can therefore help applicants access those grant funds and stretch those grant funds farther. Finally, DTE should work with prospective eFleet Charger Rebate program participants to site EV charging stations within census tracts eligible for the Alternative Fuel Vehicle Refueling Property Tax Credit.

Q. In what ways do you find DTE Electric's Benefit-Cost Analysis to be incorrect?

A. The analysis that DTE Electric presents as its benefit-cost analysis is essentially a rate-payer impact analysis and not a benefit-cost analysis. DTE counts as "benefits" the payments that electric vehicle drivers pay to DTE Electric and counts as "costs" the expenditures that DTE Electric must make to supply power for electric vehicle charging, to upgrade distribution systems, and to provide programs and rebates for electric vehicle charging. The difference between the incremental revenue to DTE Electric and costs will, in the normal course of utility regulation, accrue to DTE Electric's customers in the form of diluted rates for other uses of power. This is a ratepayer impact analysis. It is also a legitimate consideration, as the Commission should be wary of cross-subsidization of customers. However, it ignores that the electric vehicle charging revenue that exceeds the utility costs of electric vehicle charging support by the utility is a subsidy by electric vehicle drivers to other customers. From the perspective of benefit-cost analysis, it is a transfer payment between parties and is not a benefit. Similarly, rebates from the utility to electric vehicle drivers, paid for by other customers, are also a transfer payment and not a cost. DTE Electric's analysis simply demonstrates that even with the TEP programs it proposes,

there will be a net subsidy from electric vehicle drivers to other utility customers. This is a valuable demonstration that helps to justify the scale of DTE's proposed TEP and strongly supports its approval by the Commission, but it is not accurate to describe DTE's analysis as a "benefit-cost analysis" because it fails to consider the full range of costs and benefits associated with the TEP.

Q. What costs and benefits should be included in a benefit-cost analysis of DTE's TEP?

A. The National Standard Practice Manual produced by the National Energy Screening Project[39] is a good guide to benefit-cost analysis. Additionally, the Commission should note that it has long used reasonably sound benefit-cost analyses for Energy Waste Reduction or Energy Optimization programs and has recently required appropriate benefit analyses in support of its grants under the Low-Carbon Energy Infrastructure Grants program.

In essence, a sound benefit-cost analysis should identify for the whole of society and from the perspective of various stakeholders the costs of the proposed course of action and the avoided costs and externalities associated with the course of action. In the specific case of a Transportation Electrification Plan, the full list of costs and benefits would include the cost of the electric vehicle set against the avoided cost of the non-electric vehicle alternative, the utility's incremental cost of producing and distributing electricity for vehicle charging, the avoided cost of avoided fossil fuels, the change in maintenance costs of an electric vehicle versus the avoided maintenance of a traditional vehicle, the climate

[39] Which can be obtained from https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

costs of supplying power for electric vehicle charging offset by the avoided climate costs of fossil fuel for a traditional vehicle, the health costs of electricity supply for electric vehicle charging offset by the avoided health costs of avoided transportation fuel production and combustion, avoided economic and national security risks and readiness costs due to reduced dependence on volatile international oil markets, and any other cognizable costs and benefits.

Because the purchase of an electric vehicle by a DTE Electric customer would be voluntary on the part of that customer (albeit in the context of the market effects of current regulations), it would be reasonable to assume that the private benefits plus any rebates from the utility will exceed the private costs of that customer so that the utility analysis could focus on externalities and utility costs.

Q. What is the consequence of DTE Electric excluding the full range of costs and benefits from its analysis of the TEP?

A. DTE's limited analysis could lead the Company and Commission to incorrectly assess the proper level of funding for DTE Electric's TEP programs.

Q. Does DTE Electric's analysis of ratepayer impacts of its program have value to the Commission?

A. Yes, it is appropriate that the Commission consider the impacts of this program on non-participating customers and perhaps even to seek to ensure that there is not a net cost to those non-participating customers (though I note that this condition is not imposed on utility Energy Waste Reduction programs).

Q. Do you have any concerns about DTE Electric's analysis of ratepayer impacts of

electric vehicle adoption?

A. Yes. DTE attempts to attribute only a portion of electric vehicle adoption to its TEP, which I do not believe is appropriate for a ratepayer impact analysis. Instead, DTE should assess marginal revenues from EVs on a service territory and system-wide basis. This the most natural basis for assessing ratepayer impact and the most reasonable approach from a policy perspective because the total number of EVs and associated net revenue from EV charging can be reasonably calculated. This approach is also justified by analogy to line extensions, where current allowances for line extension recognize that a new customer provides revenue that will fund at least a portion of the capital expenditures that are incurred for line extension, without discounting that incremental revenue by excluding line extensions that would occur anyway without the utility allowance. I am certain that if utility allowances for line extensions were based on the percentage of line extensions that would not occur without DTE's utility allowances, there would be very little or no utility contribution to line extensions.

Q. What do you recommend the Commission decide in this case regarding Transportation Electrification?

A. I recommend that the Commission generally support DTE Electric's proposed spending, without endorsing the benefit-cost analysis as presented. I also strongly recommend that the Commission direct DTE Electric to exempt from CIAC all distribution upgrades for electric vehicle charging infrastructure. I further recommend that the Commission direct DTE Electric to include full 8760-hour annual load profiles for electric vehicle charging amongst the metrics that it will track and in future provide to the Commission and stakeholders, and to prepare and file a supplement to the Transportation Electrification Plan

that projects the combined effects of transportation electrification and compliance with Michigan's renewable and clean energy standards on grid balance, as described above.

VIII. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. On behalf of MNSC, I recommend that the Commission:

(1) Reject DTE Electric's request to recover some outage bill credits;

(2) Agree to DTE Electric's proposal to securitize tree trim surge expenses once the surge is complete, but limit return on the deferred costs to short-term debt rates;

(3) Direct DTE Electric to submit in its next rate case a seasonal approach to distribution rates reflecting that the relative utilization of its distribution system is seasonal;

(4) Direct DTE Electric to evaluate separating the residential customer class into Multi-Family, Single-Family with fossil-fueled heat, and Single Family with electric heat in both the cost-of-service study and rate design, through an alternate cost-of-service study.

(5) Approve DTE Electric's proposed spending to implement its Transportation Electrification Plan, including its proposal to defer recovery of rebates, without endorsing DTE Electric's benefit-cost analysis.

(6) Reject DTE Electric's proposal to subject utility make-ready costs to Contribution in Aid of Construction similar to line extensions.

(7) Accept DTE Electric's recommendation to not act in this case on a separate class for DC Fast Chargers.

(8) Direct DTE Electric to include full 8760-hour annual load profiles for electric vehicle charging amongst the metrics that it will track

(9) Direct DTE Electric to prepare and file a supplement to the Transportation Electrification Plan that projects the combined effects of transportation electrification and compliance with Michigan's renewable and clean energy standards on grid balance, and strategies to address any related challenges.

Q. Does that complete your testimony?

A. Yes, it does.

AG-MN 2024 / 2025 Test Year Reductions	($ in millions)	Reduction in 2024	Reduction in 2025 Test Year
4.8kV Hardening			
DTE Requested '24/ '25 Test Year		80.000	125.000
AG-MN Recommended Adjustment		(73.333)	(81.800)
AG-MN Recommended '24 / '25 Test Year Spend		6.667	43.200
Pole and Poletop Maintenance and Modernization			
DTE Requested '25		n/a	121.000
AG-MN Recommended Adjustment		n/a	(57.550)
AG-MN Recommended '25 Test Year Spend		n/a	63.450
Distribution Automation			
DTE Requested '25		n/a	125.625
AG-MN Recommended Adjustment		n/a	(101.176)
AG-MN Recommended '25 Test Year Spend		n/a	24.449
Strategic & Service Line OH to UG Pilots			
DTE Requested '24/ '25 Test Year		15.644	16.019
AG-MN Recommended Adjustment		(15.644)	(16.019)
AG-MN Recommended '24 / '25 Test Year Spend		0.000	0.000
Grid Automation Telecommunications			
DTE Requested '24/ '25 Test Year		16.900	15.000
AG-MN Recommended Adjustment		(16.900)	(15.000)
AG-MN Recommended '24 / '25 Test Year Spend		0.000	0.000
Subtransmission Redesign and Rebuild Disallowances			
Tie 4105 Phase 3 (projected to be in service in 2024)		(19.274)	0.000
Tie 4105 Phase 4 (projected to be in service in 2025)		0.000	(2.808)
Trunk 3509 (Projected to be in service 2024)		(6.062)	0.000
Total Subtransmission Redesign and Rebuild Disallowance		(25.336)	(2.808)

2024 /2025 Test Year Reduction Summary	**2024**	**2025**
4.8kV Hardening	(73.333)	(81.800)
Pole and Poletop Maintenance & Modernization	n/a	(57.550)
Distribution Automation	n/a	(101.176)
Strategic & Service Line OH to UG Pilots	(15.644)	(16.019)
Grid Automation Telecommunications	(16.900)	(15.000)
Subtransmission Redesign and Rebuild	(25.336)	(2.808)
TOTALS	**(131.213)**	**(274.353)**

Strategic Capital Programs AG-MN Disallowance Summary	**2024**	**2025**	
Infrastructure Resilience and Hardening			
4.8kV Hardening	(73.333)	(81.800)	Ex A-12 B5.4 p13 Infrastructure Resilience and Hardening line 12, col (d), (g)
Pole and Poletop Maintenance & Modernization	n/a	(57.550)	Ex A-12 B5.4 p13 Infrastructure Resilience and Hardening line 13, col (d), (g)
TOTAL Infrastructure Resilience and Hardening Disallowances	**(73.333)**	**(139.350)**	**Ex A-12 B5.4 p1 line 19 col (d), f)**
Infrastructure Redesign and Modernization			
Strategic & Service Line OH to UG Pilots	(15.644)	(16.019)	Ex A-12 B5.4 p15 Infrastructure Redesign & Modernization line 64, col (d), (g))
Subtransmission Redesign and Rebuild	(25.336)	(2.808)	Ex A-12 B5.4 p16 Infrastructure Redesign & Modernization line 114, col (d), (g))
TOTAL Infrastructure Redesign & Modernization Disallowances	**(40.980)**	**(18.827)**	**Ex A-12 B5.4 p1 line 20 col (d), f)**
Technology and Automation			
Distribution Automation	n/a	(101.176)	Ex A-12 B5.4 p17 Technology & Automation line 2, col (d), (g))
Grid Automation Telecommunications	(16.900)	(15.000)	Ex A-12 B5.4 p17 Technology & Automation line 6, col (d), (g))
TOTAL Technology and Automation Disallowances	**(16.900)**	**(116.176)**	**Ex A-12 B5.4 p1 line 21 col (d), f)**
TOTAL Strategic Capital Programs Disallowances	(131.213)	(274.353)	**Ex A-12 B5.4 p1 line 22 col (d), f)**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	Case No. U-21534

Proof of Service

On the date below, an electronic copy of **Revised Direct Testimony of Joshua W. Denzler and Douglas B. Jester, as well as Corrected Exhibit MEC-11** was served on the following:

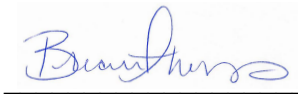
Name/Party	E-mail Address
Administrative Law Judge Hon. Sally Wallace	wallaces2@michigang.gov
DTE Electric Company Paula Johnson-Bacon Jon P. Christinidis John A. Janiszewski Breanne K. Reitzel Andrea E. Hayden	mpsc.filings@dteenergy.com paula.bacon@dteenergy.com jon.christinidis@dteenergy.com john.janiszewski@dteenergy.com Breanne.reitzel@dteenergy.com Andrea.hayden@dteenergy.com
Michigan Attorney General Joel B. King	ag-enra-spec-lit@michigan.gov kingj38@michigan.gov
Michigan Public Service Commission Staff Amit T. Singh Michael J. Orris Heather M.S. Durian Monica M. Stephens Lori Mayabb	singha9@michigan.gov orrism@michigan.gov durianh@michigan.gov stephensm11@michigan.gov mayabbl@michigan.gov
City of Ann Arbor and Michigan Municipal Association of Michigan Valerie J.M. Brader	ecf@rivenoak.com valerie@rivenoaklaw.com
Environmental Law & Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar Nicholas N. Wallace Daniel Abrams	nwallace@elpc.org dabrams@elpc.org
Utility Workers Union of America, Local 223 Benjamin L. King	bking@michworkerlaw.com

Michigan Energy Innovation Business Council, Institution for Energy Innovation, Foundry Association of Michigan, Advanced Energy United, and Energy Michigan Timothy J. Lundgren Laura A. Chappelle Justin K. Ooms	 tlundgren@potomaclaw.com lchappelle@potomaclaw.com jooms@potomaclaw.com
The Kroger Company Kurt J. Boehm Jody Kyler Cohn Justin Bieber	 kboehm@bkllawfirm.com jkylercohn@bkllawfirm.com jbieber@energystrat.com
Utility Workers Union of America, Local 223 Benjamin L. King	 bking@michworkerlaw.com
We Want Green, Too and Soulardarity Amanda Urban Mark Templeton Jacob Schuhardt Sam Heppel Madison S. Wilson	 t-9aurba@lawclinic.uchicago.edu templeton@uchicago.edu jschuhardt@uchicago.edu heppell@uchicago.edu madisonwilson@uchicago.edu
Great Lakes Renewable Energy Association Don L. Keskey Brian W. Coyer	 donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
Walmart, Inc. Melissa M. Horne	 mhorne@hcc-law.com
Association of Businesses Advocating Tariff Equity Michael J. Pattwell Stephen A. Campbell	 mpattwell@clarkhill.com scampbell@clarkhill.com
EVgo Services, LLC Nikhil Vijaykar	 nvijaykar@keyesfox.com
International Transmission Company (ITC) Richard J. Aaron Courtney F. Kissel Olivia R.C.A. Flower Hannah E. Buzolits	 raaron@dykema.com ckissel@dykema.com oflower@dykema.com hbuzolits@dykema.com
Michigan Cable Telecommunications Association Sean P. Gallagher	 sgallagher@fraserlawfirm.com
PROTEC (The Michigan Coalition to Protect the Public Rights of Way) Michael J. Watza	 mike.watza@kitch.com

{signature on following page}

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

Troposphere Legal, PLC
Counsel for MEC, NRDC, SC & CUB

Date: August 23, 2024 By: 

Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231-709-4000
Email: breanna@tropospherelegal.com